SCOMM

#16:1

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April 11, 1978

Ms. Elke Kallab, Project Officer
Alaska State Legislature
Division of Research Services
Pouch Y
Juneau, AK 99811

Dear Elke:

Enclosed are the answers to the challenging questions you sent to Battelle on March 8, 1978. We have answered questions 1a, b, & c, 2, 3a, b, & c, 4, 5, 7, & 9. In addition a discussion of "How are the entitlements regulations relevant to the ALPETCO refinery?" is included as question number ten. Questions numbered 6 & 8 were ommitted as we agreed via previous telephone conversations.

The proposed contract with ALPETCO is primarily a legal document but includes considerable technical and economic content. Our review has been limited to the latter aspects and thus our responses in no way should be considered as a legal opinion.

While formulating our answers, we observed that the impact of several of these potential issues will be dependent upon ALPETCO's success in the crude oil markets. Thus, we believe that additional information should be obtained regarding ALPETCO's planned marketing strategy for crude received prior to refinery operation. For example, as we point out in our answer to question Number 3, the weighted average netback value may decline dependent upon ALPETCO's success in the West Coast crude market.

We have enjoyed working for you, Mr. Erickson, and the State Legislators. Battelle hopes that we have fulfilled your request and that we have provided information useful for formulating state royalty oil policy. If you have any questions regarding this work or our previous royalty oil study, please call either of us. We hope that a mutual relationship has developed and that we can provide additional assistance in the future. In the meantime, we will keep our ears to the ground for new developments that may be relevant.

Sincerely,

M. Clement, Principal Investigator

W. H. Swift, Manager
Alaska Projects

Attachments

AGO 545433

QUESTION 1a

How likely is it for ALPETCO to be able to adhere to the time tables set out in Article 10.2.

ANSWER

Article 10.2 of the proposed contract with ALPETCO lists nine major milestone dates extending from the contract effective date over a period of 72 months (6 years). Construction is to be initiated by Milestone 5 or 30 months (2.5 years) from the contract effective date. The wording of Article 10.2 includes reference to apparently non-cumulative 6 to 12 month time extensions so the longest extension period (12 months) controls at Milestone 9. Most of the milestones gage performance based on ". . . expend or commit to expend . . . .". There is no specific milestone for actual refinery startup so the construction period can exceed 3.5 years. Given the scale of the endeavor, we believe more than 3.5 years for the construction period will be required.

Although it is impossible to estimate the likelihood for ALPETCO to be able to adhere to the time table in any quantitative sense, it is possible to make observations regarding each of the milestones and some of the factors that will influence their being met on schedule.

Milestone 3 (18 months)

The most difficult aspects of this milestone refer to (1) entering into contracts for sale of 70% of the product output, (2) obtaining commitments for $1.5 billion in loans or equity, and (3) completing and filing an Environmental Impact Assessment on the facility. Product sales contracts and financial commitments must to some extent be developed concurrently. This will require an intense marketing and management effort in an arena dominated by very large and experienced firms with worldwide operations. Success will depend on ALPETCO's being able to assemble a very strong team.

The completion and filing of an Environmental Impact Assessment is possible within this time period. Note however that this document would be in partial support of Environmental Impact Statements that will very likely have to be prepared by federal permitting agencies. It is these latter documents that may control timing.

Milestone 5 (30 months)

This milestone calls for definitive documentation of long-term funding and initiation of construction. Only one year is allowed from the filing of construction permit applications in Milestone 3. Since it appears likely that a number of federal permits, in addition to state permits, will be necessary, there is a strong possibility that NEPA procedures would have to be followed. These procedures call for agency preparation of draft Environmental Impact Statements and time for public comment. There is some potential vulnerability for ALPETCO in the NEPA process steming from the need to evaluate the environmental impacts of alternatives. In addition, opponents to projects have increasingly used the argument that a project must justify the "need"--the need for electric power as an example. In recent years this argument has resulted in extensive and time consuming litigation.

Milestone 9 (72 months)

This milestone as worded does not actually commit ALPETCO to complete construction of the refinery by a certain date. However, if it is assumed that this is the intent, only 3.5 years are allowed for construction. Assuming modular construction techniques are employed to the maximum extent possible this may be feasible. However the risk of delay can be substantial considering the length of the construction season available.

QUESTION 1b

In your best judgment, what affect will the lack of assured supply of 150,000 bbl/day have on the implementation and successful completion of the contract?

ANSWER

It is apparent from most forecasts, that North Slope field (as presently known) production will be peaking and possibly on the decline at about the time the proposed refinery could reasonably be expected to come on-stream. If the proposed ALPETCO project is to be totally dependent upon proven North Slope royalty crude reserves, we believe investors would be extremely reluctant to commit funds according to the milestone schedules. The question then becomes one of judging what other sources of crude supply ALPETCO may be able to contract for or at least be able to point to with the degree of assurance necessary to satisfy investing financial interests.

Another complicating factor is the possibility of a decline in the surplus crude supply on the West Coast after 1985. If this surplus were to persist, ALPETCO presumably could purchase crude from SOHIO or other North Slope producers but probably under contracts with recall provisions. The other alternatives are reserves elsewhere in Alaska but yet to be discovered. Since an Alaskan refinery is out of the mainstream, it is unlikely that non-Alaskan crudes could be economically processed.

ALPETCO could argue that, under the Emergency Petroleum Allocation Act of 1973, the federal government could assure a supply. Whether this argument would carry any weight with the banking community is conjectural.

QUESTION 1c

What possible detrimental implications exist for the State if the construction and completion of the project were substantially delayed, particularly after initiation of interim crude shipments?

ANSWER

Two potential problems will probably occur if the completion of the project is substantially delayed. (1) The first will be additional costs in the form of financing charges or interest on construction loans. (2) The second could be an inability to honor sales contracts which were entered into prior to the completion of the refinery.

(1) All delays will add to the cost of the refinery as the cost of capital (interest charges) is proportional to time. For example, assuming the refinery is financed with loans, the interest charges begin to accumulate as soon as the project is begun. In this case, interest charges began to accumulate with the proposal preparation. Each delay in the program will extend the time which these interest charges must be paid, prolongs the startup of the plant, and delays the recovery of all previous investments.

The time when the delay in the schedule occurs is also important. Early delays are not nearly as costly per unit of time because usually only a small fraction of the total investment is committed. Delays which occur later in the project will probably be more significant because a larger fraction of the total investment will have been made. At the same time these early delays may not be insignificant as interest on previous investments must be paid until the investment can be recovered via future cash flows.

These interest charges will not be insignificant. For example, assuming capital costs 10% and investments of $1 billion, (estimated total project costs range from $1.5 to $2.5 billion) annual and daily interest charges will be $100 million and $274,000, respectively. Thus, a two day delay could increase the total project cost by a half million dollars. In summary, the result of these delays is twofold. Added interest costs increase the total investment and each delay in construction delays the opportunity to recover previously invested capital.

From the State's reference, the resulting problem associated with these delays is that each delay and added cost will diminish the competitiveness of the ALPETCO plant. Eventually, the delays and additional costs will become so great the plant will not be competitive without some form of subsidy. Thus, the State may find itself in a position where it will have to grant a price reduction for crude sold to ALPETCO or some other form of subsidy, or standby and watch the plant be closed.

(2) Project delays could also affect ALPECTO's ability to honor sales contracts; ie, deliver product as scheduled in sales contracts. Most sales contracts will probably have a date for product delivery and the first delivery should be as close to the plant completion date as possible.

These product delivery dates will be important to any sales contract entered into by ALPETCO or other petrochemical producers. ALPETCO's refinery will produce several basic chemical building blocks (benzene, tolene and zylene). These products will be incorporated into intermediate and finished products by plants operating downstream in the production process. Thus, the production schedule and sales contracts of ALPETCO's and their customers must be carefully coordinated as the downstream plant's production will be dependent upon ALPETCO's production or one of their competitors. Thus, ALPETCO will be forced to commit to delivery dates if they wish to enter into any meaningful sales contracts. Project delays which affects the delivery of these products could, therefore, be critical to ALPETCO's marketing plans.

No additional significant problems associated with delays after interim crude shipments are apparent; that is, shipments to ALPETCO prior to their completion of their refinery. Article VIII seems to provide the State with adequate protection and assurance that they will receive the same revenue per barrel as if they had elected the in-value option.

NOTE: Please see the answer to question 3 also for further information.

QUESTION 2

What hazard, if any, exists that the royalty oil which may be taken by ALPETCO prior to plant startup may disrupt the West Coast oil market?

ANSWER

The issue of whether ALPETCO could undercut the price of the North Slope producers marketing crude on the West Coast has been raised based on the observation of 1) the surplus of crude in PADD V and 2) the position of SOHIO in having to market a substantial fraction of this crude in the Gulf Coast market. The suggestion has been made that since ALPETCO will receive royalty oil at the weighted average price of the producers netbacked to the lease, theoretically, ALPETCO could undercut SOHIO on the West Coast down to $10.72/bbl and bring all prices down in the process. Should this occur, there would be a substantial loss of royalty and severance tax revenues to the State.

A number of factors lead us to believe that although this outcome is theoretically possible, there a number of factors that suggest the likelihood is very low.

1. ALPETCO conceivably has two distinct West Coast markets for its oil. These are the independent refiners on the West Coast and Hawaii (671,000 bbl/day out of a total of 2,854,000 bbl/day capacity) and the major integrated oil companies.
2. The independent refiners are in general not equipped physically to process a major fraction of North Slope crude due to its higher yield of less desirable heavy products and higher sulfur content. Since their financial viability is marginal at best, capital improvement projects are unlikely. The independent refiners' very existence is largely due to the small refiners bias in the federal entitlements program.

   In addition, the small refiners are dependent upon maintaining good buyer/seller relationships with existing producers and the major oil companies. (An example of this effect has been evident in recent past sales where only the larger (126,000 bbl/day

Martinez Refining) Lion Oil Company, an independent, was a purchaser of ANS crude (19,000 bbl/day). Thus, even if the independent refiners were capable of processing additional ANS crude, it seems unlikely that they would endanger relationships.

3. The on-shore pipeline systems for moving crude oil in California are owned and operated by the major companies and do not operate as common carriers. The industry has developed a policy, however, of allowing other firms to utilize the pipeline on an exchange basis. ALPETCO will, therefore, probably be allowed to use the pipeline system, but it will require a contractual arrangement with mutual benefits.
4. For the above three reasons, we conclude that the PADD V independent refiners are not a likely market for ALPETCO's crude.
5. The motivations of the major oil companies are quite different. As integrated oil companies, they will resist any action that would destabilize the crude market and lead to price cutting. This is apparent in the recent market behavior as SOHIO has been burdened with the costly transport of ANS crude to the Gulf Coast and resisted measurable price shaving. In addition, they are probably not motivated to assist entry of a new West Coast refinery through their actions.

7 Sohio

6. Unlike the major oil companies, ALPETCO lacks the crude and product exchange flexibility that apparently is assisting marketing of ANS crude to the major refiners on the West Coast; e.g., Chevron's (minor North Slope interest) recent purchases displacing foreign imports to the Gulf Coast. In this regard, ALPETCO would be in the same position as the State were the latter to take its royalty in-kind and attempt to market it.
7. In summary, it appears that ALPETCO will be forced into the Gulf Coast and interior markets with little opportunity for price cutting occurring on the West Coast.

In addition, if ALPETCO assumes the burden of marketing the royalty fraction and must do so east of the Rockies, this reduces some of the burden on SOHIO for clearing the surplus. The net effect would be an increase in the net back for SOHIO and hence, the weighted average net back for purposes of computing royalty and severance revenues.

As will be pointed out in the answer to question 3, ALPETCO's entry into the West Coast market could reduce the netback price for at least some of the producers. Therefore, it seems unlikely that they will enthusiastically welcome ALPETCO on the West Coast.

The question raised by Dr. Arlon Tussing in his testimony before the Special Committee on Royalty Oil and Gas can be approached in another way. Dr. Tussing suggests that the producers of North Slope crude are exercising market power. The pricing behavior of SOHIO and Exxon is consistent with the monopoly hypothesis. Combined, Exxon and SOHIO control 73% of the Prudhoe Bay productions. ARCO has another 20% which it uses in its own refineries on the West Coast. Thus, nearly all of the North Slope sold on the open market is produced by two firms. The overall market price is determined by OPEC; however, within this pricing limit there is the potential for market power. This, as Dr. Tussing points out, may not be contrary to the best interest of the State of Alaska.

SOHIO and Exxon are selling ANS crude in California and in the Gulf Coast markets at substantially different "netback" prices. To the extent that the market continues to perform in this fashion, the State of Alaska royalty income will be greater by virtue of the higher prices on sale made in California or in any other location where the price is above the marginal cost of production and transportation.

The question then becomes whether ALPETCO will break the monopoly position of the current producers. It is doubtful that ALPETCO's entrance would do this for two reasons. First, the amount of oil involved in reality is quite small; second, it is not clear that ALPETCO has a strong incentive to engage in a price war. One must remember that ALPETCO's entrance into the West Coast oil market will not increase the supply of oil available. It will simply redistribute it from the present producers to ALPETCO. Most of the oil ALPETCO receives could, in theory, be sold to the same parties with whom the present producers are now dealing. Their relative inability to make exchanges would limit this to some extent.

The cost of the oil to ALPETCO will be greater than the netback price on sales to the Gulf Coast as long as the producers are selling to the California market at a higher price. If the price in both markets were driven to the same level, then ALPETCO could no longer operate as a broker for the royalty oil as its acquisition cost of crude would be the same as the going market price and ALPETCO would be unable to recover any of its marketing costs. Thus, ALPETCO can only make interim crude oil sales if the California netback price remains above the Gulf Coast price. Further ALPETCO's motives are no different than those of SOHIO or Exxon -- they will attempt to maximize their profits. To do this ALPETCO must avoid triggering a "price war" in the West Coast market.

While it is possible that ALPETCO's interim oil sales could force the West Coast netback price down to Gulf Coast netback price, it is unlikely to happen. ALPETCO in the near term has little incentive to break the price structure on the West Coast. However, any oil previously sold by the producers on the West Coast, which would be forced into the Gulf Coast market, will reduce the average netback price as calculated in the contract. (For a discussion of this point, see question 3.)

QUESTION 3

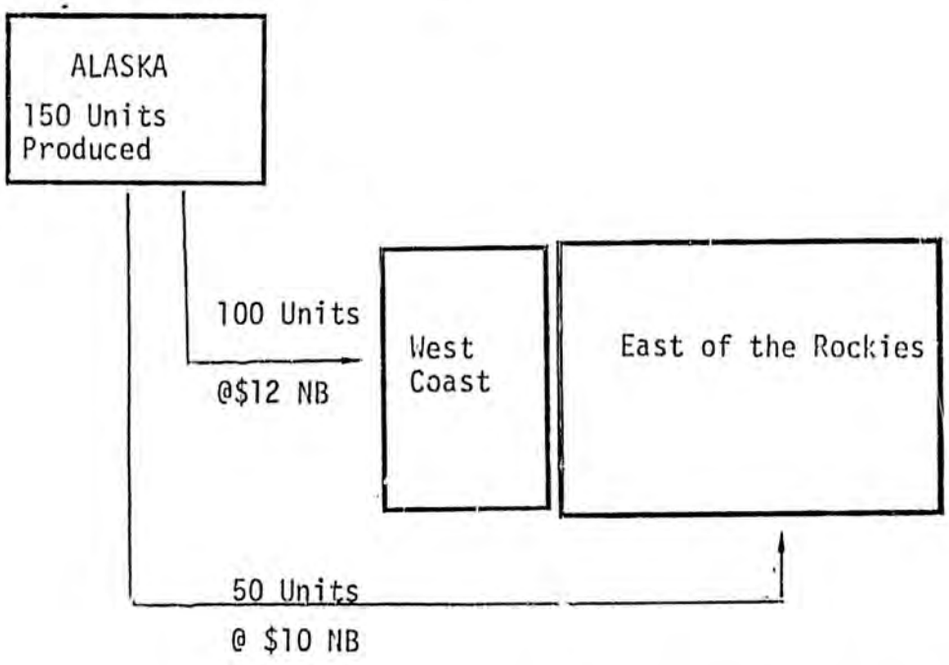
Please review the provisions governing the price to be paid by ALPETCO (Article VIII), and comment on the actual effect of the calculation method contained in Exhibit "B".

ANSWER

The pricing provisions of Article VIII and Exhibit B call for calculation of a net back price based on evaluation of all producers prices. ALPETCO must pay the State the highest price calculated using the sequence exampled in Exhibit B.

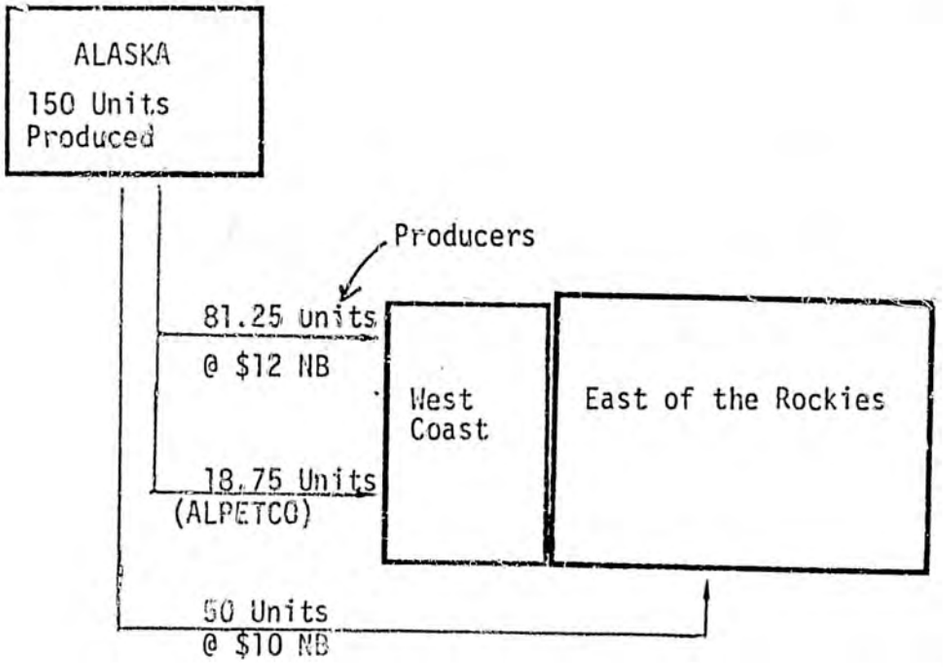
As discussed in the answer to Question 2, we do not feel that ALPETCO will be able to market crude oil received prior to plant startup on the West Coast. However, if they are able to do so, the net effect will be to reduce the net back price paid the State under Exhibit B. This situation arises from the limited ability of the West Coast refineries to absorb additional North Slope crude. If ALPETCO succeeds in marketing one-eighth of the production on the West Coast, the overflow burden to the producers will be increased by their need to market a larger quantity east of the Rockies. This situation is diagramed in the following two cases using arbitrary values.

CASE A: ALPETCO Not Marketing Crude on West Coast



Weighted Average Net Back $11.33

CASE 8: ALPETCO Markets One-Eighth of Production on West Coast



Weighted Average Net Back $11.23

reduced

Although the above cases are hypothetical, it is apparent that ALPETCO's marketing situation can significantly impact the State's revenue. The potential effect is also significant in regard to Question 1-c.

QUESTION 3a

Under what circumstances can you envision the State offering future royalty oil for less than what ALPETCO is required to pay for Prudhoe Bay royalty oil as covered in Article 2.3 and is it likely to happen? (This, of course, assumes such royalty oil becomes available for sale.)

ANSWER

Presumably the State could offer future royalty oil for less than what ALPETCO is required to pay for Prudhoe oil if such future royalty oil had an in-value price less than that for Prudhoe Bay oil. This condition would occur for new oil discovered, produced, and taken in-kind in ~~more~~ less remote regions than the North Slope resulting in a lower point of delivery price. However, ALPETCO would be interested only if their net refinery gate price would be lower taking into account additional transportation costs and any differential entitlements treatment. Such oil might be from new discoveries on the North Slope with additional transportation costs to TAPS Inlet and would, most likely, be priced under conditions similar to Prudhoe Bay oil. In this case, ALPETCO would be indifferent as long as 145,000 B/D of the latter oil is available as royalty.

Another circumstance could occur, say for a discovery in Bristol Bay, on state leases and under federal new oil price regulations. Under these conditions, ALPETCO might be able to receive oil at its refinery at a cost less than Prudhoe. (See answers to 3b and 3c.)

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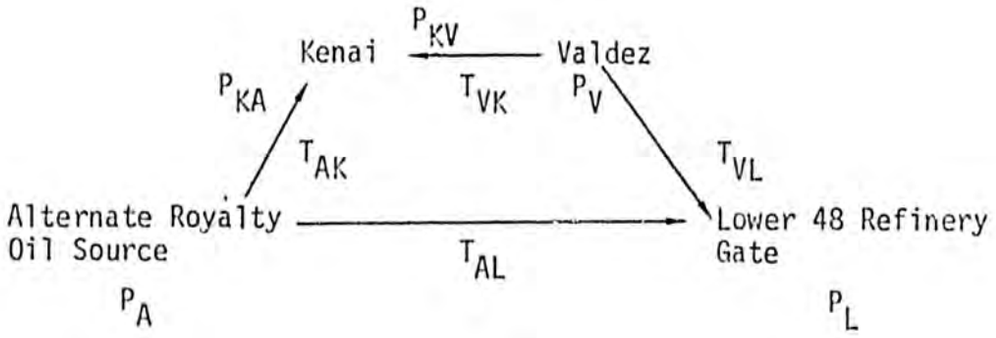
QUESTION 3b

Article 2.3 of the contract gives ALPETCO an option to purchase up to 90% of any oil that is sold or offered by the State at a price lower (taking account of transportation costs) than the price paid by ALPETCO under this contract. Given your knowledge of Alaska's oil markets, what is your assessment of the probability that circumstances which would bring this section of the contract into effect will actually occur?

ANSWER

Article 2.3 refers to royalty oil (taken in kind) other than that produced from the existing Prudhoe Bay leases. Presumably additional royalty oil could come from new leases on the North Slope, other state lands, and from the inner continental shelf. The article contains provisions relating to adjustment for transportation costs from the Prudhoe lease and the alternative sources of royalty oil.

Several circumstances could develop that would result in Article 2.3 coming into play. The first circumstance can be diagrammed as shown below and the conditions developed through the following calculation:



In the above diagram

P_L = the lower 48 refinery gate price of ANS crude
T_{VL} = transportation cost from Valdez to lower 48 refinery
T_{VK} = transportation cost from Valdez to Kenai
T_{AK} = transportation cost from alternate source to Kenai

T_{AL} = transportation cost from alternate source to lower 48 refinery

P_V = price at Valdez = $P_L - T_{VL}$

P_A = price at alternative = $P_L - T_{AL}$

P_{KV} = price at Kenai from Valdez = $P_V + T_{AK}$

P_{KA} = price at Kenai from alternate = $P_A + T_{AK}$

If P_{KA} falls below P_{KV}, ALPETCO could invoke Article 2.3: i.e., if

$$P_{KA} < P_{KV}$$

or

$$T_{AL} - T_{AK} < T_{VL} - T_{VK}$$

This situation could readily come about if

1) another source of royalty oil became available with favorable transportation costs (a new state Cook Inlet lease for example),
2) the State chose to take the royalty in kind.

(2) A second circumstance would arise for sale of royalty oil taken in kind that falls in the federal lower tier regulated category; e.g., Cook Inlet oil. An exception is for the current contract with Tesoro and renewals of that contract.

(3) A third circumstance could arise if other new discoveries made in Alaska are not allowed the special pricing treatment given the North Slope oil under federal price regulation; e.g., a new discovery might be limited to the upper tier price.

QUESTION 3c

Article 2.3 allows ALPETCO to reduce their purchases from Prudhoe Bay by the amounts purchased (presumably at lower cost) under Article 2.3. One implication of this provision may be that the State, at a future date, may be able to grant a subsidy to ALPETCO merely by offering oil from sources outside of Prudhoe Bay at prices below market value. What other implications, if any do you see in the operation of 2.3?

ANSWER

Conditions can be hypothesized such that the State of Alaska might be willing to accept less than market value for their royalty oil. For example, if the State desired to stimulate economic development with low cost energy (crude oil), then royalty crude oil might be offered at less than market value. (At the same time, it should be pointed out that the State always has the option of accepting their royalty "in-value" and therefore, does not need to accept less than fair market value for their royalty oil if revenue is their major objective).

Given that the State elects to sell their oil at less than market value, then all firms (third parties) would be offered the oil at the reduced price. ALPETCO could then gain access to this lower priced oil by exercising their option according to Article 2.3. ALPETCO would probably then reduce their purchase of Prudhoe Bay crude and replace it with oil outside of Prudhoe Bay if the delivered price (including transportation costs, etc.) for this crude were less than the price for Prudhoe Bay oil. (ALPETCO would also have access to the oil outside of Prudhoe Bay if the Prudhoe Bay oil deliveries fall below 145,000 bbl/day via Article 2.4.)

A significant point of this discussion is that State revenues from oil sales should be the same independent of ALPETCO's action with respect to Article 2.3. Once the State makes the decision to reduce the price of its oil, the State will receive less revenue per barrel. The revenue will, however, be the same if ALPETCO buys the crude at the lower price or a third party buys the oil. Thus, it seems the State should look upon the reduced price as a subsidy to all potential purchasers and not just ALPETCO. The reduced price can be interpreted as a subsidy, however, as the State could receive the market value by accepting their royalty in-value.

The review of potential subsidies via Article 2.3 has revealed one broader implication. Once the price reduction for non-Prudhoe Bay oil is in place, other pressures will probably result. For example, if the State reduces the price of any royalty oil to sitmulate economic growth, one can hypothesize that pressure will build encouraging the State to take all its royalty oil in-kind and sell it at a reduced price. After all, if it's good to sell some of the State's oil at a reduced price and offer some firms a subsidy, the State should be better off if it sold all its oil at a reduced price, including Prudhoe Bay oil. Alternatively, the State might be pressured to reduce the price of all oil slightly as opposed to granting a larger reduction on its oil outside of Prudhoe Bay. The smaller price reduction would seem to be more palatable as no one would find themselves in a relatively worse position because of the State's actions; ie, that is, all consumers of the State's royalty crude would receive an equal subsidy. ALPETCO would then not be as concerned about non-Prudhoe Bay oil if the price of all State royalty oil were reduced equally.

? that's not rational

? why not?

The impact of any price reduction has to be a reduction in State revenues assuming no increase in sales volume. ALPETCO's utilization of Article 2.3, however, should not change the State's revenues once the price concession has been granted. The State will receive the same revenue per barrel from ALPETCO as it would from any third party if ALPETCO did not exercise Article 2.3. Thus, the total revenue will be less because of the reduction in price, but the revenue should be the same if ALPETCO exercises its option according to Article 2.3. The only difference in revenue will occur if the State cannot find a new market for any Prudhoe Bay royalty oil turned back by ALPETCO. This may indeed present a problem for the State as the Prudhoe Bay oil will be higher priced and probably available in only small quantities. Of course, the State always has the option of taking its royalty in-value which eliminates the need to market the Prudhoe Bay royalty oil not taken by ALPETCO.

? why a problem?

In summary, Article 2.~~4~~ 3 appears to provide ALPETCO with some reasonable protection while probably resulting in no loss in State revenue. Basically, the clause will prevent a competing firm from moving into Alaska and obtaining royalty crude at a wellhead price less than ALPETCO is paying. This type of clause, a right of first refusal, is only prudent business practice on ALPETCO's part and is usually desired by most firms.

Furthermore, ALPETCO will maintain they took the initial risks and, therefore, should have the first chance at any future opportunities that become available; e.g., lower priced crude oil. At a minimum, they will expect some benefit from being the State's first customer and certainly not compromise their position relative to future competition. It is rather apparent that any price concession to a third party not available to ALPETCO would result in penalizing ALPETCO. Thus, they desire the right of first refusal or Article 2.3.

QUESTION NO. 4

Will the power requirements of the facility (assuming it is located on the Kenai Peninsula) create any spillover costs or benefits to other power users in southcentral Alaska?

ANSWER

ALPETCO, in their October 15, 1977 proposal, does not explicitly state the power requirements for the refinery except by the reference: ". . . . The power generation facilities alone would supply a normal city of 60,000 . . ." Assuming Alaska conditions, we estimate this amounts to a power plant capacity of about 80 MW. This value is comparable to one that can be derived from Alaska Petrofining Corporation's proposal and appears reasonable.

ALPETCO'S proposal (Section 7.3) states that "Power requirements for construction and the operation of the refinery will be self-generated with backup emergency facilities provided. ALPETCO will be able to supply emergency power to the community through a tie-in to the local power company if necessary . . ."

At the present time the Kenai Peninsula has 67.11 MW of installed capacity of which 5.8 MW are standby internal combustion units and 9.7 MW is industrial self-generation (Collier-Kenai). A 115 kV transmission line ties the Kenai system to the Anchorage area and at maximum conductor size could deliver ~50 MW.

Assuming ALPETCO proceeds with its plan to provide its own generating capacity and an emergency intertie to the Homer Electric Association system, it appears that some reliability benefits would accrue to the southcentral power system.

ALPETCO's proposal implies that refinery fuel will be self-produced as is common practice. However, under the coal conversion provisions of the probable national energy policy, this may not be possible. The alternatives are coal by rail (extension required) from the Nenana field or by barge from a newly opened Beluga field. Steam requirements for process heat and power generation are indicated by ALPETCO to be 5.5 million lbs/hr. The coal requirements at this level amount to 3-4 million tons/year. This rate is probably in excess of a feasible mining rate in the Nenana Field but approaching the mining rate necessary to support a major export mine at the Beluga Capps Field with associated railway to tidewater and loading pier.

A substantial development at Beluga would be required over and above the possible 2-200 MW CEA plants under consideration for 1984 and 1986. The State may wish to question ALPETCO as to their refinery fuel plans.

QUESTION 5

Under Article 2.4 of the contract, the state will be committing up to 70% of otherwise uncommitted non-Prudhoe Bay royalty oil to fill out any shortfalls in the 150,000 barrels per day which ALPETCO needs. Since it is almost certain that royalty oil from Prudhoe Bay will fall far short of the 150,000 barrels per day, this provision seems to sharply reduce our options with respect to disposal of any royalty oil which might become available in the future. Presumably, market conditions and other factors may change substantially between now and the time that this option is exercised. Taking into account the pricing provisions in Article 8.1 (and exhibit "B"), what is the likelihood that we would be able to get a better deal in the future if we weren't bound by this option?

ANSWER

Clause 2.4 of the contract will probably reduce the State's options regarding royalty oil which might become available in the future. The reduction in the State's flexibility may occur, if other royalty oil becomes available, when the North Slope royalty oil is less than ALPETCO's requirements and if a third party desires the new royalty oil; this also assumes ALPETCO constructs and operates its proposed plant. The real question is to what degree will the State's options be diminished and what opportunities will be foregone because of Clause 2.4? In terms of lost or foregone revenue, we believe very little, if any, will be lost. The primary potential loss will be the freedom to enter into unconstrained marketing contracts, but these future contracts will only be needed if several conditions occur (e.g., new large discoveries of crude and rapid growth in petrochemicals markets which could support a second Alaskan plant).

Similarly, market conditions will change with time and possibly the State may be able to arrange a "better deal" in the future if the State were not bound by Clause 2.4; e.g., attract a second plant. The probability, however, that a significantly better deal could be arranged seems slight. The contract has several clauses to protect the State's interests and to assure that the State does not forego any potential revenue. (Admittedly, a second plant will provide benefits in addition to revenues, but consideration of these benefits is beyond this work.) Specific reasons to support these conclusions are provided below.

The primary loss or opportunity cost associated with Clause 2.4 may be the potential loss of an opportunity to lure a second firm to Alaska. This assumes the State would be able to attract a second firm with their crude oil supply, but will not have a sufficient supply to satisfy ALPETCO's needs and at least partially satisfy the needs of a second firm. Given the experience associated with attracting the first firm (ALPETCO) and uncertain petrochemical market conditions, the probability of attracting a second firm to Alaska seems rather low at this time. On the other hand, if there is a need for two refineries and the economics prove attractive, the producers could build the second plant, produce the desired products in Alaska, and ship less of their crude to the West Coast of the lower 48 where a significant surplus will prevail at least through 1985 and probably beyond.

ALPETCO will probably exercise their option and request that the State allow them to purchase royalty oil in addition to the Prudhoe Bay royalty oil, assuming additional State royalty oil is available. This contractual option (to fill out any shortfalls in ALPETCO's need of 150,000 B/D) will definitely limit the State's options for disposing any royalty oil which may become available in the future. Again, the question is a matter of degree, ie, will the State be severely limited, and if so, how? For example, the State will not be able to offer an assured supply to another firm unless a substantial new oil discovery occurs on State lands. At the same time, the State's revenue should be essentially the same regardless of whether ALPETCO exercises its option regarding "otherwise uncommitted non-Prudhoe Bay royalty oil to fill out any shortfalls in the 150,000 B/D" potentially required by ALPETCO. Several clauses in the contract were identified which should protect the State's future revenue and assure that it will be essentially the same whether ALPETCO exercises its options, buys other royalty oil, or a third party buys the State's royalty oil. The clauses (8.1.3) are:

> "The price of oil sold pursuant to the provisions of Article 2.4 shall be the greater of: (i) the best and highest price offered by a bona fide offerer for a like quality and quantity of crude oil to be produced from such lease out of which oil is being delivered; or (ii) a price equal to the sum seller would have received from its lessee or lessees had seller received its royalty in value instead of taking the quantity of royalty oil delivered hereunder as its royalty in-kind (amounts)."

where does the quote end?

In addition, the price shall be computed in accordance with Exhibit B. The Buyer will also reimburse "Seller's pro rata share of (i) any basic sediment and water removal cost if seller is required to pay such cost as a result of seller's election to take its royalty oil in-kind; and (ii) any other direct cost reasonably incurred by seller had the seller taken its royalty in-value rather than in-kind." These clauses apply to ALPETCO and any third party and seem to give the State reasonable assurance that it will receive the same revenue whether or not ALPETCO exercises its option for non-Prudhoe royalty oil. In addition, analysis completed in Battelle's Royalty Oil Market Study found that the State's revenue was always greater with the in-value option than the in-kind option for oil marketed outside of the State. The previous two clauses regarding highest offer or revenue equal to in-value revenue seem to assure that the State will not lose any potential revenue as a result of contractual clauses granting ALPETCO the previously described option. Any loss incurred is more one of control and influence over future marketing contracts while the opportunity costs seem negligible if any occur. The loss in control and influence are essentially intangible and cannot be measured against the benefits of a potential in-State sale to ALPETCO. (The in-State sale will increase the State's revenue by $0.90 to $3.00 per barrel dependent upon where the oil would have to be marketed and the associated transportation costs.) Assuming the oil is not sold to ALPETCO, the clause providing them the option to purchase non-Prudhoe royalty oil should give ALPETCO a more assured supply and inturn aid them in obtaining financing. Also these options are frequently offered to the firm which incurs the initial risk. This "right of first refusal" provides them with an incentive to begin the project and also to protect them from future competition in a market that may not be able to support two large firms.

QUESTION 7

Under Article 4.3, ALPETCO is required to construct a facility that will be capable of producing 30,000 bbl/day of energy fuels for "intra-state domestic and industrial needs". In light of the probability that the full 150,000 bbl/day of royalty crude will not be available, what is the likelihood that ALPETCO would leave this capacity idle in order to maximize petrochemical product output? (Presumably ALPETCO could conceivably devote all production to petrochemicals even if they did get the full 150,000 bbl/day of royalty or other source oil.)

ANSWER

ALPETCO should not prefer to have any portion of their plant idle. After they have made the investment in the facility, they should attempt to operate at full capacity; ie, 150,000 bbl/day of crude. If ALPETCO cannot obtain the full 150,000 bbl/day of crude from the State, then they will have a strong incentive to buy crude from other suppliers. Crude should be available from producers such as SOHIO. The product from this production should be petrochemicals equivalent to 120,000 bbl/day and energy fuels equivalent to 30,000 bbl/day for a total of 150,000 bbl/day of crude oil requirements.

Given a case where ALPETCO may not be able to obtain the full 150,000 bbl/day of crude oil requirements, ALPETCO may still wish to produce the energy fuels for the instate market as opposed to maximizing production of petrochemicals at the expense of energy fuels. Two reasons for this are that (1) energy fuels will probably be consumed within the State and, therefore, less transportation costs will be incurred. (2) The second reason is that production of energy fuels via the ALPETCO plant should be considerably less costly than petrochemicals. The result of this is that energy fuels should be at least as profitable, if not more so, than petrochemicals. (Of course, the absolute profits for each product will be dependent upon the allocation of cost between the two plants, the operating efficiencies of each plant, the eventual price for each product produced, etc. None of this data is available now, so a precise evaluation is not possible.) Given the assumption that energy fuels are at least as profitable, then ALPETCO should maximize production of energy fuels and produce up to an equivalent of 30,000 bbl/day of crude assuming they can market their products.

Assuming ALPETCO constructs a 30,000 bbl/day energy fuels plant, they will probably produce all the energy fuels they can market. Based upon the straight-run design specified in their proposal, ALPETCO's energy fuels plant should be competitive in Alaska. Even if the plant is not profitable in Alaska, ALPETCO will probably produce as much as they can market after the plant is constructed. Once the plant is constructed, their investment is a sunk cost and the only way they can recover their investment is to operate the fuels plant. They should operate the plant as long as they can sell their product at a price which is greater than their variable costs; this will allow them to recover a portion of their investment each time they produce and sell another unit of energy fuel.

In evaluating ALPETCO's option, Alaska's future demand for energy fuels and current production capacity was examined. Existing refineries can produce 82,600 bbl/day; ie, Chevron at 22,000, Tesoro at 38,000, and North Pole at 22,600 (excluding the ARCO North Slope refinery of 13,000 bbl/day). After the ALPETCO plant is completed, the State will have a refining capacity of 112,600 bbl/day. A forecast of demand prepared by the Institute of Social and Economic Research, University of Alaska, February 1978, provides a liberal projection for petroleum liquids. The demand in 1976 was equivalent to 62,100 bbl/day (see Table 1). This demand is projected to grow to 112,600 bbl/day in about 1987 which is equivalent to ALaksa's refining capacity assuming the ALPETCO plant is constructed. Thus, some of ALPETCO's production may be surplus to the State's needs and have to be exported to the lower 48 during the early years of ALPETCO's plant, if the projected demand for product turns out to be overestimated.

? Why? need not operate at 30M; rather put it into petro-Chemical production! Cheaper to market fuel via export?

TABLE 1. Demand for Petroleum Liquids[1/]

	1976	1980	1985	1987	1990	2000
Million Barrels of Crude Oil Equivalent per Year	22.7	28.5	35.2	41.1	46.9	81.2
Thousand Barrels of Crude Oil Equivalent per Day	62.2	78.1	96.4	112.1	128.5	222.5

1/ Institute of Social and Economic Research, University of Alaska, Energy Intensive Industry for Alaska - Phase I, pp. D22 & D36, February 1978.

ALPETCO will probably never devote all production (150,000 bbl/day of crude) to petrochemicals assuming they receive the 150,000 bbl/day of crude from the State. The basic reason for this is a design constraints. The design of the ALPETCO plant specifies crude requirements of 150,000 bbl/day and energy fuel production of 30,000 bbl/day leaving an equivalent of 120,000 bbl/day for petrochemicals production. This essentially fixes the maximum equivalent daily production of petrochemicals at 120,000 bbl/day of crude. Additional capacity would have to be designed into the plant if production is to be significantly greater than 120,000 bbl/day. This additional capacity is too costly to include, or at least not a good allocation of funds, if it is not to be utilized routinely; i.e., if they plan to produce 150,000 bbl/day of petrochemicals per day they need a plant of this capacity and not a plant with 120,000 bbl/day capacity. Similarly, they would attempt to secure an appropriate volume of crude oil as feedstock.

QUESTION 9

What are the implications of requiring all future contracts to contain a provision which gives ALPETCO the paramount right to receive up to 70% of available royalty oil which is or could be taken in kind as far as volume and financing is concerned?

ANSWER

The apparent implication of Article 2.4 is that all other crude oil purchase contracts between the State and third parties will be subservient to ALPETCO's needs. According to this Article the State must allow ALPETCO to receive up to 150,000 barrels per day. Only after the State has satisfied ALPETCO's crude oil requirements is it free to supply royalty crude to third parties. Thus, supply contracts, if they exist, will be dependent upon ALPETCO's needs and also interruptable if necessary to satisfy ALPETCO's needs. The apparent result is that contracts of this nature will be somewhat less attractive to third parties.

This right in the proposed contract (Article 2.4) is intended to strengthen ALPETCO's position in seeking financing for the project and hence, strengthening the probability of success of the project. However, the clause does appear to restrict the flexibility the State would have to react to possible future changes in the crude oil market situation. An example (and possibly an extreme one) would be a lift of the prohibition on the export to Japan.

Reviewing the contract today, however, indicates that Article 2.4 is only a potential limitation and is perhaps a small concession to assure the consummation of a contract with ALPETCO. For example, before Article 2.4 limits the State in anyway, numerous events must occur. Some of these are:

- ALPETCO must build and operate its refinery,
- Oil must be discovered and produced on State lands outside of Prudhoe Bay, and
- A third party must desire the State's royalty oil outside of Prudhoe Bay.

In addition, the State has restrictions limiting ALPETCO's purchases of State crude to 150,000 barrels per day. They must also pay a price equivalent to the in-value price or the best and highest price approved by a bona fide offerer for a like quality and quantity of crude oil as dictated by Article 8.1.3. These conditions will temper the apparent impacts of Article 2.4 and insure that the State receives essentially the same revenue independent of the purchaser.

QUESTION 10

How are the entitlements regulations relevant to the ALPETCO refinery?

ANSWER

If the ALPETCO refinery were operating today, all North Slope crude it processed would receive an "entitlements benefit" amounting to $2.01/bbl. This amount does not include any special entitlements treatment such as the small refinery bias since the Economic Regulatory Administration (ERA) must make an individual determination of eligibility. If the 30,000 bbl/day fuels refinery were treated separately from the rest of the facility, the small refinery bias would be significantly greater for the ALPETCO plant. The per barrel value of the small refinery bias for a 30,000 bbl/day refinery is approximately $0.90 and $0.10 for a 120,000 bbl/day refinery as opposed to $0.05 for a 150,000 bbl/day refinery. Under the prevailing rules, separate treatment of each facility would produce incremental refinery revenues of $31,500/day when operating at full capacity.

Presently, no refined product exports are being made; thus, there have been no ERA rules established on the right of a refiner to earn entitlements credits on crude refined for export. The current situation in California with respect to the excess supply of residual fuel oils has prompted the ERA to investigate the ramifications of exporting refined products. In that process, a precedent will be established regarding the entitlements treatment of crude refined for export.

The last entitlements regulation, which is uncertain at this point, is the special provision for California refineries. At the present time each barrel of ANS crude refined in California receives an entitlement credit valued at $1.34; that is, $0.67 less than the credit to ANS crude refined outside California. However, the ERA is in the process of changing the California provisions. One likely outcome will be to spread the special lower tier California oil credit over all imported and ANS oil refined in the U.S. rather than just the foreign and ANS crude processed in California. This will give an equal credit to ANS crude refined in the Gulf Coast States and in California.

One should keep in mind that the entitlements program may be phased out by some form of a Crude Oil Equalization Tax. But given the large subsidy to small refineries present in the entitlements program, it is highly probable that a small refinery subsidy will be continued even after the entitlements program is dismantled. Whether it will be as extensive as the current program remains to be seen.

STATE OF ALASKA
THE LEGISLATURE

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907 465-3800

You have asked that we prepare a memorandum for you outlining the possible subsidies/liabilities contained in the ALPETCO contract as they have been raised in public hearings to date.

I. Subsidies

Essentially, the administration is correct when it maintains that the contract is free of subsidies. Items which could be considered subsidies--in the broadest sense of the word--are listed below.

A. Price Reduction

A potential subsidy exists under Article 22, which allows Article 8 (Price) to be amended by reducing the in-value price ALPETCO has to pay the State. This is a potential subsidy, which several witnesses felt would come to pass.

B. Breaking of West Coast Pricing Mechanism

Arlon Tussing testified at length how ALPETCO could obtain a price "subsidy" for Prudhoe Bay royalty oil. He outlined how ALPETCO could break the West Coast market by selling the interim crude to which they become entitled on the West Coast at a substantially lower price than the established West Coast price, thereby reducing the value the State would be receiving for its royalty share. Furthermore, this subsidy could be prolonged and intensified by ALPETCO if ALPETCO continued to market part or all of the Prudhoe Bay royalty oil on the West Coast after the petrochemical facility comes on stream, instead of using it as feedstock. Even if ALPETCO were to utilize its supply of royalty oil in the petrochemical facility after it becomes operational, Mr. Tussing felt that it would be very difficult to return the price of crude oil on the West Coast

to its former high level. Again, the State would grant ALPETCO a subsidy, since the value of the oil on which the State receives its royalty would be reduced.

C. Pipeline Fill

You already pointed out that a subsidy of sorts exists under Article 2.6 by virtue of the State agreeing to provide ALPETCO with pipeline fill and storage tank bottom requirements for the life of the contract at no cost to ALPETCO until the expiration of the contract. The amount of money involved has been estimated to amount to approximately $9,000,000.

D. Article 2.3

The question has been raised repeatedly if Article 2.3 constituted a subsidy. A subsidy would exist if the price of future royalty oil, which would be made available by the State, would be ~~offered for~~ less than ALPETCO would be required to pay under Article 8.1, and ALPETCO were to exercise its option under Article 2.3 and purchase up to 90 percent of such crude. However, it should be noted that this subsidy would apply equally to all bidders, not just ALPETCO, although ALPETCO would have first option. If the State refrained from offering future royalty oil for less than in-value price, it is unlikely that this option could ever come into effect.

E. Costs to the State

Commissioner LeResche listed several costs which would be imposed on the State as a result of approval of the ALPETCO contract. Whether they should be included as subsidies is questionable, but they do represent costs the State would not have to incur if the State were to continue to take its Prudhoe Bay crude in value.

The added administrative costs listed by Commissioner LeResche included:

1. Monitoring the contract.
2. Helping in the site selection.
3. Added accounting work as a result of taking our royalty share in-kind.
4. Litigating the question of free storage rights under the leases.
5. Processing and approving permit applications.
6. Measuring and testing of crude oil.
7. Obtaining crude assays.
8. Helping in designing the training and resident hire programs set out in the contract.
9. Implementing and monitoring those programs.

In addition, we would add the costs incurred by State personnel under Articles 5.3, 5.4, and 8.2. While litigation under Articles 5.3 and 8.2 may be at ALPETCO's cost, there could be considerable indirect expenses incurred over and above the costs covered in the contract as a result of State employees devoting time and effort to the litigation, costs which are very difficult to quantify. Article 5.4 provides for an appointed State official "who shall act as Seller's coordinator for the purpose of facilitating the granting of permits by Seller and to act as a liaison officer for Buyer and Seller with the federal government." Since there is no provision in the contract as to who pays for this effort, it is assumed that the State will absorb this cost. These as well as other work which the State will be called upon to perform are costs for which no reimbursement provision exists unlike the situation which existed with the TAPS project and unlike the present agreement in principle for reimbursement of State incurred costs during the construction of the Alcan pipeline.

II. Liabilities

There are numerous instances which might be labelled liabilities to the State if the ALPETCO contract were approved. However, we believe that some of these liabilities are more perceptual than factual. Nevertheless, we are listing them here as they have emerged in public hearings for your review.

A. Performance Bench Marks

Some people feel that the so-called performance bench marks under Article 10 are inadequate to assure the State that ALPETCO will actually have to complete the envisioned petrochemical facility and bring it on stream, since the commitment of money to the project rather than an enforceable construction timetable seems to be the overriding factor in judging ALPETCO's performance. This concern is further accentuated by--

(1) the delays and extensions which can be granted to ALPETCO, and

(2) the fact that ALPETCO would be allowed to continue to take oil during this period, precluding the State to do anything else with its Prudhoe Bay royalty share.

Along similar lines, Mr. Lipton noted that if ALPETCO could not meet the bench mark dates set out in Article 10, it would be unlikely that the State would cancel the contract, because "as long as things continue to look prospective, one goes along."

B. Processing of Oil in Petrochemical Facility

The contract does not provide that the Prudhoe Bay royalty oil must be processed in the envisioned petrochemical facility

(4.2.1), nor is ALPETCO required to process 30,000 b/d at the proposed refinery for in-state use (4.3).

C. "Brokering" of Oil

Concern has been expressed that there is nothing in the contract which could prevent ALPETCO from continuing to "broker" a certain amount of Prudhoe Bay royalty crude or, for that matter, all of their entitlement after the petrochemical facility comes on stream (13.1).

D. Size of Petrochemical Facility

The contract only requires ALPETCO to expend an aggregate amount of $1.5 billion. Yet, all presentations by ALPETCO claim that the contemplated facility will cost $2.5 billion or more, and all the benefits which have been cited by ALPETCO are based on a $2.5 billion facility. If the project came in at $1.5 billion, the promised benefits to Alaska would be diminished.

E. Article 2.4

Aside from the 70 percent option of future royalty oil, which might become available for in-kind taking, to which ALPETCO is entitled under the contract, this article provides that all future contracts "shall contain a provision that Buyer shall possess a paramount right to call for and receive such royalty oil in the event deliveries to Seller from the Leases and available for sale and delivery to Buyer fall below 145,000 barrels per day...." This requirement might prevent the State from entering into any meaningful, realistic, or competitive long-term contracts with other parties, since the State cannot assure supply.

III. Other Points Which Have Been Raised

Messrs. Lipton and Tussing pointed out that--

A. The major oil and chemical companies did not bid on Prudhoe Bay royalty oil which made the sale contingent on the construction of a petrochemical facility in Alaska. Conversely, it has been pointed out that ALPETCO has limited marketing and financing capabilities.

B. The Japanese market, on which ALPETCO relies so heavily, can be supplied more advantageously from other places than Alaska, and representations by ALPETCO about Japanese interest appear inflated.

C. The project could get financing, even be on stream, and not be profitable. The likelihood that the State would let the project flounder or go under is unthinkable. Mr. Lipton

stated that the State would feel responsible to help ALPETCO, since--

(1) it would be the only major project in Alaska, and

(2) if the State did not come to the aid of ALPETCO during a difficult time, it may be viewed by others as the State not seriously considering development.

We believe the above points fairly summarize potential liabilities to the State which have surfaced to date. Questions which Battelle Northwest and ISER have been asked to address have not been touched upon in this memorandum. We hope you find the information useful.

EK:jm

P.S. We are enclosing a copy of a memorandum from Randy Berry which addresses several legal questions previously raised regarding the ALPETCO contract.

(Enclosure)

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

MEMORANDUM

April 5, 1978

SUBJECT: Questions regarding ALPETCO contract

TO: Elke Kallab

FROM: Randolph Berry
Revisor of Statutes

The three questions which I will attempt to deal with in this memorandum are the adequacy of the security provisions, the article relating to successors and assignees, and the effect of the use of the term "commit to expend" in Article 10.3 relating to time periods for performance by the buyer.

(1) With regard to the security provisions of the contract, Article 12.1, as discussed by Mr. Rogers, is an attempt by the parties to solve the problem resulting from the prohibition by certain owners of the TAPS pipeline on carriage of oil on which a lien exists. The language is intended to result in the release of the purchase money security interest at the time the oil enters the pipeline and its reattachment when the oil emerges from the pipeline at Valdez. The provision imposes certain obligations on the buyer to prevent the attachment of other liens at this point, and to the extent that the buyer complies with these obligations, the provision seems reasonably workable. In the event that the buyer does not comply with his obligations, the state would be in a position to hold the buyer in default but could find itself without the priority lien which the provision envisions as protecting the state. However, Article 12.2, with its alternate security provisions, would appear to adequately protect the state if it was actually put into effect.

(2) As to the provision relating to assignment of and succession, written approval by the state is required prior to the voluntary assignment by ALPETCO of its interest in the contract to a trustee or lender as security for bonds or indebtedness. Further approval by the state is not required in the event of foreclosure or other assumption of ownership

AGO 545468

rights by the trustee or lender but the state would retain all its security interests until all sums owed to the state under the agreement were paid. Although it is possible for the agreement to be assigned by the trustee or lender to a third party without approval by the state, this could only be done if that third party assumed all the obligations and liabilities of the buyer under the agreement.

(3) The term "commit to expend" used in Article 10.2, was explained by Mr. Rogers as meaning entering into a binding contract for construction or purchase of materials or equipment relating to the petrochemical facility, but without any requirement in Article 10.2 as to time for performance of these contracts. While it is understandable that the buyer would prefer not to have time limits for completion of the facility specified in the agreement, since the agreement does not give the state any right to review or approve the terms of the construction contracts, the state is left somewhat at the mercy of ALPETCO as to the timetable for the actual construction of the petrochemical facility.

RB:jpd

STATE OF ALASKA
THE LEGISLATURE

LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

MEMORANDUM

March 27, 1978

SUBJECT: Entitlements - ALPETCO Contract

TO: The Honorable Bill Miles

FROM: Elke Kallab
Research Analyst

I have received your note regarding the entitlements program and how ALPETCO might or could use it.

I have spoken to the administrator of the Entitlements Program in ERA and he told me that presently ALPETCO's entitlements would amount to $2.07/bl, plus roughly 5¢ under the small refiner bias. These entitlements would most likely be applicable to the total 150,000 bbl/d petrochemical facility capacity, not just the 30,000 bbl/d energy fuels refinery capacity.

The entitlements ($2.07/bl) would be applicable during the interim taking of crude as well, since the entitlements accrue to the refiner.

Unlike what the attached letter from Bonner and Moore seems to indicate, the ERA felt that crude oil used to make products intended for export by the petrochemical facility would be subject to the entitlements.

The above information was offered in a telephone conversation, and specifics might have to be modified if the subject is thoroughly investigated. However, I believe the information might provide you with some idea about the size of the entitlement available to ALPETCO.

We have also asked Battelle to look at your question and to respond to it along with the other questions which they are addressing.

answered as Question #10.

EK:jm
Attachment

cc: Marv Clement, Battelle

AGO 545470

Copy given to Ward Swift 2/16/78

Bonner & Moore Associates, Inc.

500 Jefferson | Cullen Center
Houston Texas 77002
Area Code 713 659-1871
Cable: BONMOR

February 10, 1978

RECEIVED
FEB 11 1978
Department of
Natural Resources

Dr. Robert E. LeResche, Commissioner
State of Alaska
Department of Natural Resources
11th Floor, State Office Building
Pouch M.
Juneau, Alaska 99811

Dear Commissioner LeResche:

I am writing to comment on two recent developments that favorably affect the evaluation that we made of the Alaska Petrochemical Company (Alpetco) project. The first development is the conditional agreement of Mr. Gordon Caine to join Alpetco as Chief Executive Officer. The second pertains to a re-examination of Alpetco's economics. Mr. Caine, now Chairman of Petrotex Chemical Corporation, is personally and professionally known to me. He has industry experience and stature that will add greatly to the credibility and competence of any future Alpetco project implementation. While this development doesn't equate with the existence of a major petrochemical line and staff management organization it definitely would eliminate the strong negative rating that was given Alpetco in the management area. My management rankings would not change but Mr. Caine's presence and the continued use of Chem Systems as Consultants would more closely equate the management resources of Alpetco and Alaska Oil & Chemical Company.

It has also been brought to my attention that representatives of Alpetco have questioned our economic evaluation of their proposed royalty oil project. Specifically, an objection has been raised that no crude oil entitlement credit was included in our evaluation. After discussions with Mr. Willard Hanzlik of Alaska Interstate I now believe that the Alpetco project should properly be credited with some crude oil entitlement.

The crude oil entitlement program is designed to equalize the cost advantage among US refiners of purchasing price controlled domestic crude oil. Crude oil processed to produce material for export is specifically excluded from consideration in determining the degree of crude cost equalization due a refiner.

In the Alpetco economic calculations submitted as an Appendix to their proposal to the Royalty Board no credit was taken for a crude oil entitlement. Because of this curious omission the Alpetco spokesman was specifically questioned on the point during the November public hearings in Valdez. At that time it was stated that Alpetco had investigated the matter and concluded no entitlement credit would be available for their project. Since reference was also made to supplying export markets from the proposed Alpetco plant the omission of entitlement credits appeared to be correct.

After discussing this matter with Mr. Hanzlik, I am convinced that Mr. Barbour's Valdez statement was incorrect or does not properly reflect the current project realities. If our evaluation is not constrained by the record of Alpetco's proposal and prior public testimony then my judgment would be that a crude oil entitlement ranging from $1.15 to $2.30 should be credited to the Alpetco evaluation.

The lower figure would correspond to a case where half the plant output were petrochemicals and were exported. The remaining half would then be fuel products and be sold domestically. In the case where all products were sold domestically the higher entitlement would apply. These cases, in our judgment, bracket all real situations that might apply to Alpetco. Since the matter of Alpetco's exports seems so uncertain it is difficult to be more definitive.

The critical table that should reflect this change in our evaluation is Table 8, Page 3-13. A revised table is attached.

Section 4, Conclusions should be modified consequently. Our ranking, A. Economic Viability, would now list:

1. Alpetco
2. Alaska Petrofining
3. Alaska Petroleum Co.

Our commentary would state: The element of uncertainty in the Alpetco economic projections would suggest that both the Alpetco and Alaska Petrofining proposals should be viewed as substantially and comparably viable. The Alaska Petroleum proposal is somewhat less attractive, economically, but still fully qualified.

Comments about Alpetco in the report Summary do not warrant changing. In that section we cited only the uncertain business prospects. It has been my judgment that Alpetco was content with the project's economics and their determination to go forward was not qualified in our evaluation. The business uncertainties surrounding both the Alpetco and Alaska Oil & Chemical projects remain substantial, compared to the refinery projects.

Very truly yours,

Joe F. Moore
President

JFM:me
Attachment

cc: Mr. Don Wold
Mr. Charles Honig
Mr. Willard M. Hanzlik

TABLE 8

ALPETCO CRUDE PRICE COMPARISONS

	BONNER & MOORE ($/B)
In-Value Price Range Excluding Field Costs	6.04 - 6.33
In-Value Price Range Including Field Costs	5.41 - 5.76
Deemed Economic Price Range	5.95 - 7.10
Deemed Economic Price Range Using Alpetco's Average Product Price of $30.33/B	7.63 - 8.78

What Entitlements would accrue to ALPETCO

Now!

Under Proposed Amendments!

- 150MB/d Petrochemical facility
- 30M B/d energy fuels refinery capacity for in-State use

- Interim taking of crude, roughly from 1979 through 1983 or longer.

- Products to be marketed on W. C and ~~Pacific Rim~~ Japan.

Alaska oil in the rule
is treated as if it
were not for entitlement
purposes

get entitlement

Net effect → 2.07/b Jan. '78
↓
reduce the cost to a
refiner by that amt

ALPETCO – precedents that
Petrochem – treated as refinery

Entitlements accrue to refiner
not ALPETCO
↓
indirect benefit to ALPETCO

Mont Clemens 509 946-2270

~~Rulemaking~~

Small refiner ~~[illegible]~~ bias

100 11¢

150M b/d ——————> 5¢/b (rough)

175M 0¢

~~[illegible]~~

AGO 545477

DOE

Entitlements Program

(1) Stan Mills - audit + Enforcement
202 254 3070

- March Hearing
Entitlement Hearings

(2) Doug McIver - Econ. Reg. adm. ERA
adm. - Entitlements Program
202 254-8660

Attorney
General Counsel
(3) Margaret Dinneen
202 566-9565

Proposed Amendments to Entitlements Program Chei

State Representative
→ Written Testimony - Tom Williams
North Pole Refinery
GVEA
ARCO
Rice - Center of Environment
ALPETCO

AGO 545478

Sunday

Elke:

What can we find out about Now Alpetro can/plans/may use the ~~entitlements~~ program?

B. Nile

AGO 545479

Elke - Reveal

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

MEMORANDUM

March 20, 1978

SUBJECT: ALPETCO Sales Contract (W.O. #5141)

TO: Representative Bill Miles

FROM: Randolph Berry, Revisor of Statutes

The purpose of this memorandum is to answer and discuss the questions developed by Elke Kallab regarding the proposed ALPETCO contract. These questions will be responded to in the order presented in the request.

1. (a) Article 2.3 prevents the state from entering into any long term sale of royalty oil at a "lower price" than that of the royalty oil sold to ALPETCO. The state can sell royalty oil for a lower price for a short term (up until the petrochemical facility is operational), but could not enter into a long term contract for sale at a lower price which would extend beyond the date the facility is operational. Use of the effective date of the contract appears to immediately guarantee ALPETCO the protection of this section, but in fact makes little or no difference, since the critical factor is not whether the state enters into a contract with a third party, but whether the state ceases sales at the lower price on the date that the petrochemical facility begins processing crude oil.

(b) Article 10.2(3)(d) does not prevent ALPETCO from receiving royalty oil prior to the end of the 18-month period; the 18-month time frame is the period within which ALPETCO must comply with the requirements of Art. 10.2(3). If ALPETCO has obtained the financing commitment contained in Art. 10.2(3)(d) in a lesser period of time, then it would be eligible to call for initiation of delivery under Art. 2.2 at that time. Although Art. 2.3 would already be in effect, it would only apply if the offer to a third party at a lower price extends beyond the initiation of processing by the petrochemical facility.

2. Although the contract document is dated February 22, 1978, the actual date of execution for the purposes of Art. 2.4 would be the date of final signing of the contract, rather than the February 22, 1978 date reflected on the first page of the contract document.

AGO 545480 +

3. Article 4.2.2 provides that the commissioner, in deciding whether to approve or disapprove a proposed site, "shall consider the desires of the people who live in the immediate surroundings of any proposed site." This does not require the commissioner's decision to be controlled by the objection. However, the approval or disapproval of a site for the facility under Art. 4.2.2 only is relevant to compliance with the contract, and does not give ALPETCO any additional rights to build the facility in a particular location. ALPETCO would still be subject to any local or state zoning or other land use restrictions to the same extent as any other private company.

4. Art. 4.3 does not actually require ALPETCO to produce energy fuel for in-state use. ALPETCO is required to build into the petrochemical facility the capacity to process 30,000 barrels of crude oils per day into energy fuels. Although ALPETCO does not appear under the contract terms to be required to actually utilize the specified capacity to produce that quantity of energy fuel, in this and other instances in the contract it seems to be assumed that the required investment will operate as sufficient economic incentive to bring about the desired performance by ALPETCO. The provision contains the additional requirement that if ALPETCO does not use the royalty oil in its petrochemical facility, then it shall utilize its "best effort" to assure that 30,000 barrels per day be processed in-state into energy fuels. Presumably this would be applicable should ALPETCO begin to take delivery of royalty oil under the contract prior to the completion of the petrochemical facility. In this context, "best effort" would mean that ALPETCO would be required to take all reasonable steps to achieve in-state processing; although what is reasonable in a particular situation may be open to differences of opinion, it is a commonly used judicial concept.

5. Although study of the language of the provisions of Art. 10.2 relating to extensions of the time limits for contract performance by ALPETCO leads me to the conclusion that total extensions are limited to the single longest extension and do not cumulate, (and this interpretation is supported by comments by the Commissioner of the Department of Natural Resources), the manner in which the contract was drafted with repeated reference to a six month extension after each time limit could lead to confusion, and in my view, a written agreement by the department and ALPETCO as to the meaning of the extension provision would be helpful.

6. No. It would perhaps be helpful to one not familiar with the contract, but it is not necessary.

7. Although Articles 15.2(vii) and (viii) are comparatively broad in their scope, presumably the particular language of these provisions was the result of contract negotiations, and the advisability of the language used is a policy rather than a legal question.

8. Although the legislature cannot itself amend the contract, any of the contract provisions would be open to amendment if the department and ALPETCO agreed to the amendment prior to approval by the legislature.

Additional questions:

9. Article 12:

The question raised is whether the provision requiring voter approval of contract amendments resulting in a reduction of the price paid to the state could cause timing problems. The answer is yes; however, it appears that this provision would be more likely to work to the detriment of ALPETCO than the state, since it would delay the effect of a price reduction.

10. Article 2.3 and 2.4:

Does the legislature forego the opportunity to vote on any future sales contracts which may be executed by the administration by virtue of Articles 2.3 and 2.4?

Any offer of sale made under Art. 2.3 would be a new offer for sale of royalty oil for purposes of AS 38.05.183 and AS 38.06 and would be subject to royalty board and legislative approval. However, the operation of Art. 2.4 would not appear to be a new sale, and royalty board and legislative approval of the current ALPETCO contract would appear to be sufficient to allow Art. 2.4 to come into operation without further approval.

RB:hjd

Elke

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y · STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

MEMORANDUM March 20, 1978

SUBJECT: ALPETCO Sales Contract (W.O. #5141)

TO: Representative Bill Miles

FROM: Randolph Berry, Revisor of Statutes

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1. (a) Article 2.3 prevents the state from entering into any long term sale of royalty oil at a "lower price" than that of the royalty oil sold to ALPETCO. The state can sell royalty oil for a lower price for a short term (up until the petrochemical facility is operational), but could not enter into a long term contract for sale at a lower price which would extend beyond the date the facility is operational. Use of the effective date of the contract appears to immediately guarantee ALPETCO the protection of this section, but in fact makes little or no difference, since the critical factor is not whether the state enters into a contract with a third party, but whether the state ceases sales at the lower price on the date that the petrochemical facility begins processing crude oil.

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2. Although the contract document is dated February 22, 1978, the actual date of execution for the purposes of Art. 2.4 would be the date of final signing of the contract, rather than the February 22, 1978 date reflected on the first page of the contract document.

✓ ?

I believe the contract has been signed! / wrong

AGO 545483

3. Article 4.2.2 provides that the commissioner, in deciding whether to approve or disapprove a proposed site, "shall consider the desires of the people who live in the immediate surroundings of any proposed site." This does not require the commissioner's decision to be controlled by the objection. However, the approval or disapproval of a site for the facility under Art. 4.2.2 only is relevant to compliance with the contract, and does not give ALPETCO any additional rights to build the facility in a particular location. ALPETCO would still be subject to any local or state zoning or other land use restrictions to the same extent as any other private company.

4. Art. 4.3 does not actually require ALPETCO to produce energy fuel for in-state use. ALPETCO is required to build into the petrochemical facility the capacity to process 30,000 barrels of crude oils per day into energy fuels. Although ALPETCO does not appear under the contract terms to be required to actually utilize the specified capacity to produce that quantity of energy fuel, in this and other instances in the contract it seems to be assumed that the required investment will operate as sufficient economic incentive to bring about the desired performance by ALPETCO. The provision contains the additional requirement that if ALPETCO does not use the royalty oil in its petrochemical facility, then it shall utilize its "best effort" to assure that 30,000 barrels per day be processed in-state into energy fuels. Presumably this would be applicable should ALPETCO begin to take delivery of royalty oil under the contract prior to the completion of the petrochemical facility. In this context, "best effort" would mean that ALPETCO would be required to take all reasonable steps to achieve in-state processing; although what is reasonable in a particular situation may be open to differences of opinion, it is a commonly used judicial concept.

5. Although study of the language of the provisions of Art. 10.2 relating to extensions of the time limits for contract performance by ALPETCO leads me to the conclusion that total extensions are limited to six months, (and this interpretation is supported by comments by the Commissioner of the Department of Natural Resources), the manner in which the contract was drafted with repeated reference to a six month extension after each time limit could lead to confusion, and in my view, a written agreement by the department and ALPETCO as to the meaning of the extension provision would be helpful.

6. No. It would perhaps be helpful to one not familiar with the contract, but it is not necessary.

7. Although Articles 15.2(vii) and (viii) are comparatively broad in their scope, presumably the particular language of these provisions was the result of contract negotiations, and the advisability of the language used is a policy rather than a legal question.

8. Although the legislature cannot itself amend the contract, any of the contract provisions would be open to amendment if the department and ALPETCO agreed to the amendment prior to approval by the legislature.

RB:hjd

For Randy Berry - 3/20/78

Questions raised--

By Battelle: Article 10

"Expend or commit to expend or cause contractually bound parties to expend or commit to expend..." means very little in terms of actual performance or completion of such commitments. (Jerry McCutcheon hinted at this as well).

By Rep. Chat Chatterton: Article 14.3

What does "material or substantial" mean in this context. Suppose the State incurred no financial loss; would a court still find ALPETCO in default, breach or failure of performance? When is it material or substantial?

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

MEMORANDUM

March 16, 1978

SUBJECT: ALPETCO Contract - W.O. #5141

TO: Randy Berry
Staff Attorney

FROM: Elke Kallab Elk
Research Analyst

Rep. Joe McKinnon has asked that we look at the section of Article 2.3 which requires the State to "first offer to Buyer the opportunity to purchase ninety percent of the royalty oil proposed to be offered. Said oil shall be offered to Buyer at the same price, and on the same terms and conditions, as offered to third parties." Mr. McKinnon's concern is that under this provision the State could get locked into a long-term contract with ALPETCO way beyond the termination date of the ALPETCO contract now before the legislature. We discussed this same section of Article 2.3 with Fred Boness on Tuesday, although in a different context, and were told by him that "opportunity to purchase" means that a new contract would have to be submitted each time Article 2.3 is exercised, which would have to have Royalty Board and legislative approval before it could become effective.

What Mr. McKinnon would like to have is your written confirmation that any volumes acquired by Article 2.3 would require individual contracts, necessitating legislative approvals.

EK:jm

cc: Hon. Joe McKinnon
Hon. Bill Miles

AGO 545487 +

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

MEMORANDUM

March 14, 1978

SUBJECT: ALPETCO Contract - W.O. #5141

TO: Randy Berry
Staff Attorney

FROM: Elke Kallab Elk
Research Analyst

An additional question has been raised with regard to articles 2.3 and 2.4, and we would appreciate your comments.

> Does the legislature forego the opportunity to vote on any future sales contracts which may be executed by the Administration by virtue of articles 2.3 and 2.4?

Thank you!

EK:jm

AGO 545488

STATE OF ALASKA
THE LEGISLATURE

LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

March 10, 1978

MEMORANDUM

SUBJECT: Legal and Research Division Activities Related to Royalty Oil Studies.

TO: The Honorable John Rader
The Honorable Mike Colletta
The Honorable Kay Poland
The Honorable John Sackett
The Honorable Hugh Malone
The Honorable Bill Miles

FROM: Gregg K. Erickson
Director of Research

The purpose of this memo is to bring you up to date on what the agency is doing with respect to the administration's proposed sale of North Slope royalty oil to ALPETCO. We would appreciate any comments you might have on our current efforts, or other questions you believe might be appropriate for us to look at.

1. We have had underway since December of last year a study by Battelle Northwest evaluating the U.S. and worldwide markets for Alaska royalty crude, particularly in relation to the possible sale that crude under a long term, no strings attached, contract. This study has already produced some very valuable and useful information, and will be presented in its entirety to the legislature on March 16.

2. The Institute of Social and Economic Research at the University of Alaska is doing, under contract to the agency, an economic impact analysis of the proposed ALPETCO facility. The initial output of the study will be available April 7, and additional work will continue on it until the funds allocated ($18,000) are exhausted, or the legislature acts on the contract, whichever occurs first. This study will particularly look at the population effects of the construction and operation of the ALPETCO facility, changes in personal income, overall impact on state revenues from sources other than proceeds of royalty oil sale, and related matters. This is primarily in an econometric study and will be under the supervision of Scott Goldsmith.

AGO 545489

3. In addition to the contract noted above in (1), Battelle Northwest is also addressing some specific questions which have been raised by the ALPETCO contract. A list of these questions is attached. We would be particularly interested in any additions which you might suggest. So far we have allocated $10,000 of agency funds for this project. We hope to have responses to most or all of these questions before April 15.

4. The agency's legal staff is investigating whether the procedures followed by the administration in negotiating the ALPETCO contract were in conformance with state law, and the question of whether the commitment of undeveloped and undiscovered royalty oil is consistent with the statute. We hope to have preliminary answers to these questions by March 15, and a final report by the end of the month. Attached is a list of other questions being addressed by the agency's legal staff.

5. In addition to administering the contract work under (1-3) above, the research staff is looking into the pricing provisions contained in the ALPETCO contract. Further, we have prepared, and are adding to as we go along, a list of questions that the legislature itself may wish to address.

Attachments:
1. ISER Contract
2. List of questions for Battelle
3. List of questions for agency legal staff
4. List of other questions

GKE:dh

AGO 545490

CONTRACT BETWEEN

STATE OF ALASKA

LEGISLATIVE AFFAIRS AGENCY

AND

UNIVERSITY OF ALASKA

INSTITUTE OF SOCIAL AND ECONOMIC RESEARCH

The parties of this agreement are the LEGISLATIVE AFFAIRS AGENCY, on behalf of the Alaska State Legislature, hereinafter referred to as the "Agency", and the UNIVERSITY OF ALASKA, INSTITUTE OF SOCIAL AND ECONOMIC RESEARCH, hereinafter referred to as the "Contractor".

THE PURPOSE OF THIS AGREEMENT is to provide the Legislature and the State with expert economic information on the expected effects of a proposed petrochemical processing facility.

IT IS THEREFORE MUTUALLY AGREED THAT:

CLAUSE I. - STATEMENT OF WORK

(A) (PHASE I) - The Contractor shall prepare estimates of the economic impact of the petrochemical manufacturing facility proposed to be built by Alaska Petrochemical Company, with particular attention to changes in employment levels, personal income, state and local taxes, and population. The Contractor shall assume that the proposed facility will be sited in the vicinity of the city of Kenai. The estimates shall be conducted using the Contractor's MAP model of the Alaska economy.

(B) (PHASE II) - The Contractor shall conduct such further analysis of the benefits and costs of proposed sale of royalty hydrocarbons as the Agency may from time to time request. Requests shall be submitted in writing.

CLAUSE II. - CONTRACTOR'S STAFF

The Contractor's principal investigator for work under this agreement will be Dr. Scott Goldsmith. The Contractor may assign other members of its staff to this project as it considers appropriate.

AGO 545491

CLAUSE III. - PERIOD OF PERFORMANCE

(A) Work under Clause I(A)(Phase I) of this contract shall be performed between 15 January 1978 and 7 April 1978. The Contractor recognizes that time is of the essence in completion of this phase of the work, and that the work product may be of no value to the Agency if delivered after 7 April 1978.

(B) Work under Clause II(B)(Phase II) shall be conducted prior to 30 June 1978. Individual tasks shall be completed by the dates specified in the written requests for such work.

(C) This contract may be terminated after 7 April 1978 by written notice of either party to the other.

CLAUSE IV. - PROJECT DIRECTOR

The Project Director shall be Gregg Erickson, Director of Research, Legislative Affairs Agency.

CLAUSE V. - COMPENSATION AND METHOD OF PAYMENT

(A) Contractor's compensation for the work specified in Clause I(A) shall be , payable on completion of Phase I.

(b) Contractor shall be compensated for the work done under Clause I(B) at the Contractor's published daily rates, a copy of which is attached to and made a part of this contract.

(C) Expenses incurred by the Contractor in the completion of the work set forth in Clause I(A) shall be borne by the Contractor. Expenses incurred by the Contractor in completion of the work set forth in Clause I(B) shall be reimbursable by the Agency. Costs of travel approved in advance in writing by the Project Director shall be reimbursable to the Contractor on the basis of state per diem rates and coach class air fare.

(D) Total compensation under this contract, including expenses, may not exceed $18,000.

CLAUSE VI. - IN-CASH CONTRIBUTION

The Agency understands that the Contractor intends to apply the payment made under this contract to the "in-cash" and "overhead" contribution required in support of the "Research Proposal to Environmental Management Program, the Ford Foundation". The Agency neither endorses nor objects to this procedure.

CLAUSE VII. - RECORDS, DOCUMENTS, AUDIT

(A) The Contractor shall maintain accurate records as may be required by the Project Director. The records are subject to inspection by the Agency or the Project Director at all reasonable times.

AGO 545492

(B) All documents, reports and writings generated as a consequence of work done under this contract shall become the property of the State of Alaska, and on completion of the work or at the termination of this contract shall be delivered to the Agency.

CLAUSE VIII. - REPORTS

The Contractor shall keep the Project Director informed as to the progress of the work performed under this agreement and shall provide progress reports as specified by him.

CLAUSE IX. - ALL WRITINGS CONTAINED HEREIN

This agreement contains all the terms and conditions agreed upon by the parties. No other understandings, oral or otherwise, regarding the subject matter of this agreement shall be deemed to exist or to bind either of the parties of this agreement.

IN WITNESS WHEREOF, the parties have executed this agreement on the dates noted.

UNIVERSITY OF ALASKA, INSTITUTE OF SOCIAL AND ECONOMIC RESEARCH		LEGISLATIVE AFFAIRS AGENCY	
E. LEE GORSUCH	Date	GREGG K. ERICKSON	Date
Accepted: UNIVERSITY OF ALASKA		Approved as to form:	
HOWARD A. CUTLER Chancellor	Date	AGENCY LEGAL COUNSEL	

Attachment

AGO 545493

Nine Questions

Priorities	Question #	
(1)	2.	2 pp.
(2)	1.	
(3)	5.	
(4)	7.	
(5)	3.	
(6)	9.	
(7)	4.	
(8) + (9)	6. and 8. will not be addressed by Battelle	

LEGISLATIVE AFFAIRS AGENCY

March 8, 1978

Questions for Ward Swift, Battelle Northwest (as per letter of 3/8/78)

1. What overall probability would you assign to the likelihood that the ALPETCO project will actually come to fruition in the manner contemplated in the contract?

a point out pitfalls! and reasons which might be causes of delay!

a. How likely is it for ALPETCO to be able to adhere to the time tables set out in article 10.2? (~~We have asked our legal~~ people to seek clarification concerning ~~the extensions~~ of the various phases, since ~~it is not~~ clear whether the possible extensions are ~~cumulative~~ over the six years [10.2(1) to 10.2(10)]. They could extend the time table by an additional ~~52 months plus, if all extensions were granted to the maximum.)~~

b. In your best judgement, what affect will the lack of an assured supply of 150,000 b/d have on the implementation and successful completion of the contract?

problem with ALPETCO delivering the oil

c. What possible detrimental implications exist for the state if the construction and completion of the project were substantially delayed, particularly after the initiation of interim crude shipments?

2. What hazard, if any, exists that the royalty oil which may be taken by ALPETCO prior to plant start-up may disrupt the west coast oil market? Gulf Coast not W.C where oil will wind up.

not disrupt! not ~~[illegible]~~ able to mkt it!

3. Please review the provisions governing the price to be paid by ALPETCO (Article VIII), and comment on the actual effect of the calculation method contained in Exhibit "B".

a. Under what circumstances can you envision the state offering future royalty oil for less than what ALPETCO is required to pay for Prudhoe Bay royalty oil as covered in article 2.3, [redacted] (~~[illegible]~~)

low

same

b. ~~([illegible], sent yesterday). Article 2.3 of the contract gives ALPETCO an option to purchase up to 90% of any oil that is sold [illegible] by the state at a price [illegible] account of transportation costs) than the price paid by ALPETCO [illegible]~~ Given your knowledge of Alaska's oil market's, what is your assessment of the probability that circumstances which would bring this section of the contract into effect will actually occur?

c. Article 2.3 allows ALPETCO to reduce their purchases from Prudhoe Bay by the amounts purchased (~~presumably at lower cost~~) under article 2.3. One implication of this provision may be that the state, at a future date, may be able to grant a subsidy to ALPETCO merely by offering oil from sources outside of Prudhoe Bay at prices below market value. What other implications, if any do you see in the operation of 2.3?

AGO 545495

4. Will the power requirements of the facility (assuming it is located on the Kenai Penninsula) create any spillover costs or benefits to other power users in southcentral Alaska?

~~5. Under article 2.4 of the contract, the state will be committing up to 50% of otherwise uncommitted non-Prudhoe Bay royalty oil to fill out any shortfalls in the 150,000 barrels per day which ALPETCO needs. Since it is almost certain that royalty oil from Prudhoe Bay will fall far short of the 150,000 barrels per day, this provision seems to sharply reduce our options with respect to disposal of any royalty oil which might become available in the future.~~ Presumably, market conditions and other factors may change substantially between now and the time that this option is exercised. Taking into account the pricing provisions in article 8.1 (and Exhibit "B"), what is the likelihood that we would be able to get a better deal in the future if we weren't bound by this option?

~~6. The administration maintains that there are no risks or subsidies involved in this contract. Do you agree?~~

7. Under article 4.3 ALPETCO is required to construct a facility that will be capable of producing 30,000 barrels per day of energy fuels for "intra-state domestic and industrial needs". In light of the probability that the full 150,000 barrels per day of royalty crude will not be available, what is the likelihood that ALPETCO would leave this capacity idle in order to maximize petrochemical product output? (Presumably ALPETCO could conceivably devote all production to petrochemicals even if they did get the full 150,000 barrels per day of royalty or other source oil.)

8. Some observers have claimed that Alaska's negotiating stance, both with respect to the now cancelled royalty gas contracts and with respect to this contract, has created an impression "outside" that Alaska is not really serious about developing industry in the state. Do you have any information that would tend to confirm or refute the notion that we are being perceived this way?

9. What are the implications of requiring all future contracts to contain a provision which gives ALPETCO the paramount right to receive up to 70 percent of available royalty oil which is or could be taken in kind as far as volume and financing is concerned?

[redacted]

STATE OF ALASKA
THE LEGISLATURE

LEGISLATIVE AFFAIRS AGENCY

March 8, 1978

Questions for Ward Swift, Battelle Northwest (as per letter of 3/8/78)

1. What overall probability would you assign to the likelihood that the ALPETCO project will actually come to fruition in the manner contemplated in the contract?

   a. How likely is it for ALPETCO to be able to adhere to the time tables set out in article 10.2? (We have asked our legal people to seek clarification concerning the extensions of the various phases, since it is not clear whether the possible extensions are cumulative over the six years [10.2(1) to 10.2(10]). They could extend the time table by an additional 52 months plus, if all extensions were granted to the maximum.)

   b. In your best judgement, what affect will the lack of an assured supply of 150,000 b/d have on the implementation and successful completion of the contract?

   c. What possible detrimental implications exist for the state if the construction and completion of the project were substantially delayed, particularly after the initiation of interim crude shipments?

2. What hazard, if any, exists that the royalty oil which may be taken by ALPETCO prior to plant start-up may disrupt the west coast oil market?

3. Please review the provisions governing the price to be paid by ALPETCO (Article VIII), and comment on the actual effect of the calculation method contained in Exhibit "B".

   a. Under what circumstances can you envision the state offering future royalty oil for less than what ALPETCO is required to pay for Prudhoe Bay royalty oil as covered in article 2.3, and is it likely to happen? (This, of course assumes such royalty oil becomes available for sale.)

4. Will the power requirements of the facility (assuming it is located on the Kenai Penninsula) create any spillover costs or benefits to other power users in southcentral Alaska?

(More to come tomorrow.)

AGO 545497

STATE OF ALASKA
THE LEGISLATURE

LEGISLATIVE AFFAIRS AGENCY

More Questions for Ward Swift, Battelle Northwest
(as per letter of 3/8/78)

3(b). (Elaboration of question 3, sent yesterday). Article 2.3 of the contract gives ALPETCO an option to purchase up to 90% of any oil that is sold or offered by the state at a price lower (taking account of transportation costs) than the price paid by ALPETCO under this contract. Given your knowledge of Alaska's oil market's, what is your assessment of the probability that circumstances which would bring this section of the contract into effect will actually occur?

(c). Article 2.3 allows ALPETCO to reduce their purchases from Prudhoe Bay by the amounts purchased (presumably at lower cost) under article 2.3. One implication of this provision may be that the state, at a future date, may be able to grant a subsidy to ALPETCO merely by offering oil from sources outside of Prudhoe Bay at prices below market value. What other implications, if any do you see in the operation of 2.3?

5. Under article 2.4 of the contract, the state will be committing up to 70% of otherwise uncommitted non-Prudhoe Bay royalty oil to fill out any shortfalls in the 150,000 barrels per day which ALPETCO needs. Since it is almost certain that royalty oil from Prudhoe Bay will fall far short of the 150,000 barrels per day, this provision seems to sharply reduce our options with respect to disposal of any royalty oil which might become available in the future. Presumably, market conditions and other factors may change substantially between now and the time that this option is exercised. Taking into account the pricing provisions in article 8.1 (and Exhibit "B"), what is the likelihood that we would be able to get a better deal in the future if we weren't bound by this option?

6. The administration maintains that there are no risks or subsidies involved in this contract. Do you agree?

7. Under article 4.3 ALPETCO is required to construct a facility that will be capable of producing 30,000 barrels per day of energy fuels for "intra-state domestic and industrial needs". In light of the probability that the full 150,000 barrels per day of royalty crude will not be available, what is the likelihood that ALPETCO would leave this capacity idle in order to maximize petrochemical product output? (Presumably ALPETCO could conceivably devote all production to petrochemicals even if they did get the full 150,000 barrels per day of royalty or other source oil.)

AGO 545498

8. Some observers have claimed that Alaska's negotiating stance, both with respect to the now cancelled royalty gas contracts and with respect to this contract, has created an impression "outside" that Alaska is not really serious about developing industry in the state. Do you have any information that would tend to confirm or refute the notion that we are being perceived this way?

End of Questions

Telecopied
(automatic)
9:00 am
3-14-78
mm

509-946-2718

Question for Ward Swift, Battelle

9. What are the implications of requiring all future contracts to contain a provision which gives ALPETCO the paramount right to receive up to 70 percent of available royalty oil which is or could be taken in kind as far as volume and financing is concerned?

Questions submitted to Legal ~~Services~~ Division regarding work order on ALPETCO sales contract.

1. 2.3 - This section essentially entitles ALPETCO to receive, as of the effective date of the contract, up to 90% of other royalty oil that may be offered for sale by the State, if it is sold at less than what ALPETCO is required to pay for Prudhoe Bay royalty crude.

The section further states that the State can sell other than Prudhoe Bay royalty oil at a lower price until the petrochemical facility initiates processing of crude oil.

The questions are:

a. If the State can sell available royalty oil under Article 2.3 for less, up until the facility comes on stream, then why should it be tied to the effective date?

b. Since ALPETCO cannot receive Prudhoe Bay royalty oil until 18 months after the effective date of the contract at the earliest (2.2), why should the option of being able to take up to 90% of other royalty oil which is priced lower than Prudhoe Bay royalty oil be available to ALPETCO on the effective date of the contract?

2. 2.4 - The contract states that "...to protect and insure Buyer's right to receive at least 150,000 barrels of crude oil per day hereunder, after the date of execution hereof...". You stated that "date of execution" meant the signing of the contract, which would be February 22, 1978.

How can the State obligate itself to the provision of 2.4 before the contract becomes effective? Should "date of execution" maybe have been "effective date", and if so, how important is it to change it?

3. 4.2.2 - What legal recourse, if any, would a community have which was adjacent to the proposed site, and which objected to the location of the site? Does the contract language need to be changed?

4. 4.3 - Please clarify if this provision requires ALPETCO to produce up to 30,000 b/d of energy fuel for in-state use, or if it provides only for ALPETCO to "...utilize its best efforts to assure that at least 30,000 barrels per day of...royalty oil will be processed in-state for production into energy fuels for intrastate distribution and sale..." if it is not utilized in the petrochemical facility.

What is meant by "best efforts", and should it be defined to show what is intended? (This term is defined in 8.2.)

5. 10.2 - Need clarification of headings 10.2(2) through 10.2(9) as they relate to the extensions granted under them individually. (Maybe a provision for maximum amount of time for all extensions and delays [site selection] would solve the problem, although the Legislature will not be able to make that change.)

6. 4.2.2 - Is it necessary to reflect the cancellation option available to ALPETCO after two site disapprovals in 4.2.2?

7. 15.2(vii) (viii) These two force majeure clauses seem to be too loose and all inclusive. Do they need to be modified to protect the State's best interests? How about any of the other force majeure clauses?

8. Under what terms, if any, can the contract as presented to the Legislature be modified?

Also, would you please review the comments of Messrs. Phillips, Nizer, et al, carefully (I previously gave you a copy) to see what additional bearing they have, if any, on the existing contract. I am not always sure if their suggestions were incorporated, and if they were not, if it flaws the contract as a result of disregarding them.

Would you please pay particular attention as to the adequacy of Articles XII (Security) and XXIII (Successors and Assigns), since I am probably not sufficiently versed in these areas to ask the right questions.

MEMORANDUM

March 10, 1978

SUBJECT: ALPETCO Contract - W.O. #5141

TO: Randy Berry

FROM: Elke Kallab

In addition to the questions posed in W.O. 5141, would you also look at the following question:

Article XXII - This article provides for voter approval should the price under Article VIII be reduced. The question has been raised what problems might exist with the provision as far as timing is concerned? (For example, if ALPETCO waits until December 1980 to ask for a reduction in price, it appears voters would not be asked to vote on the question until the next general election, or November 1982.)

Thank you!

EK:jm

AGO 545504 +

3/9/78

Other Issues Which Require Attention:

1. 1.13 - Why are "total project costs" allowable back to 1975? Since ALPETCO did not come into existence until 1977, and since the State did not offer its Prudhoe Bay royalty oil for in-kind sale until 1977, what kind of expenses prior to that time could have been incurred, by whom, and for what amounts?

Answered ACS 000-1,000,00

2. 2.6 - The State has agreed to supply ALPETCO with the pipeline fill and storage tank bottom requirements so that ALPETCO can fulfill their tariff obligations to TAPS. (The Administration advises us that approximately 1,000,000 barrels are involved.)

   The State has further agreed to provide these volumes free of charge until termination of the contract.

3. 5.3 - While ALPETCO agrees to pay the costs of any litigation to clarify the State's legal storage rights under the leases, who pays the incidental costs of such litigation and how will they be determined? (AG's staff time, etc.)

4. 5.4 - a. What are the problems associated with the State on the one hand utilizing its best efforts to facilitate and support the granting and approving of ALPETCO's permits, and on the other hand being the regulator and issuer of these permits, and is this desirable?

   b. Should the State fund the state coordinator or should the State be reimbursed by ALPETCO, since it is acting on ALPETCO's behalf?

5. 5.5(ii) - This article provides that the State furnish ALPETCO with production schedules of solution gas, gas cap gas and condensate which are available from Prudhoe Bay. Why? The administration states that they have advised ALPETCO that the State could not legally provide ALPETCO with confidential material. If ALPETCO is confined to public data, which would be available to everyone, why make it a contractual item? If the purpose of the section is for the Administration to gather the data for ALPETCO, should the State be reimbursed by ALPETCO for providing this service?

Answered

6. The contract commits ALPETCO to expend $1.5 billion in total project costs, including expenditures by governmental entities for required facilities in connection with the construction and operation of the petrochemical facility.

ALPETCO is on record that the proposed facility will cost $2.5 billion. Is there any possibility that under the contract terms ALPETCO could scale down the facility to $1.5 billion?

7. Final process configuration and production rates of the products to be produced at the facility will be determined by marketing considerations based on sales contracts for the products. What implication does this have for the final projected facility as currently proposed by ALPETCO? (See 6 above.)

8. Article 10.2 deals with a time-frame ALPETCO has to follow and allows for extensions under the various benchmark dates. No provision is made in 10.2 for additional delays which may be caused by site disapprovals by the State, and resubmissions of proposed site locations by ALPETCO (4.2.2).

9. Is the security interest under Article 12 and 10.2 sufficient to protect the State's best interests, or should other requirements be added to assure successful completion and implementation of the project, such as performance bonds or liquidated damages?

3/9/78

Environmental Questions and Answers

1. 4.2.2 - *Are 90 days sufficient to rule on the site?*

JERRY REINWAND: Yes, in the context of the contract.

2. 10.2 (3)(f) - *What is the difference between an Environmental Impact Assessment and an EIS?*

JERRY REINWAND: An Environmental Impact Assessment is a "mini" EIS and usually precedes an EIS if one is required.

Will an EIS be required?

JERRY REINWAND: Yes, probably from the Feds (Corps).

3. *Exhibit "D"*

Check with DEC if they concur with the coverage. Is it sufficient? Are the limits and deductible enough to be properly covered?

JERRY REINWAND: Totally satisfied with Exhibit "D".

Overall, Mr. Reinwand thought the contract was quite adequate as far as DEC was concerned.

M E M O R A N D U M

TO: Representative Bill Miles

FROM: Lisa Nelson, Administrative Assistant

DATE: June 1, 1978

RE: Statements on taking oil in-kind and in-value

LeResche, Senate Special Committee on Royalty Oil and Gas, May 15, 1978

LeResche said in essence, the House amendment will cause the contract to fall apart. He explained: "Given the Unit Agreement and given the other set of factors, i. e. the way the petrochemical industry works, they might run 165,000 barrels one day, 140,000 the next; they might shut down for 3 weeks.

Meanwhile, try to work that within the six-month notice period; there may be a 12 - 20 day transportation period from Prudhoe to ALPETCO, it is clear that there is no way to adjust what we take from the producers finally enough to ensure that every barrel does go through this refinery, unless they have ridiculously large storage facilities which would make the project financially silly.

So, mechanically it doesn't work.

May 16, 1978, Fred Boness with House Special Committee on Royalty Oil and Gas

In the North Pole contract, Section 2.2.2 addresses the ability of North Pole Refinery to increase and decrease the amounts of oil they wish to receive.

Discussion was as follows:

Chatterton: This apparently can be done from month-to-month.

Boness: That's right.

Chatterton: As I read over here on page 6, that's not going to give the Department any trouble in administering this, it it?

Boness: No, we have the right to give daily notices to the producers which are effective 6 months thereafter.

Miles: If they are taking 35,000 (b/d), let's say they are taking the max, of Prudhoe, and they get a better deal from ARCO, then they say stop, just deliver the minimum, what does the State do with the 30,000?

Boness: We go back to taking in-value.

Miles: And there is no problem at all just going back and taking in-value there? I mean there is no problem with the producers or anything else?

Boness: No, provided you give the proper notice. The producers could have problems, but we have a legal right... it shouldn't cause the State any problem. We expect to have somebody that is responsible for administering these contracts. I mean, it is no different than having to send out a bill.

Chatterton: If there is no difficulty in administering this, why, then,there is no difficulty in administering this in any contract for the sale of royalty oil? Right?

Boness: Right. Wait, I am not sure, I feel like I am missing something here.

Chatterton: I think you are.

Fred explains that a good contract administrator is needed to assure the contract is strongly and fairly administered.

Chatterton: What I think I read... If I am North Pole, and I am taking 30,000 barrels per day of oil, but I think seven months down the road, I am only going to want to take five or ten thousand (b/d), I will give you notice, and you will give the producers notice, and so, we can drop to that amount in seven months.

Now I heard people testify that you wouldn't be able to do that in regards to other royalty oil sales contracts.

Now, why can you do it with one and not do it with another?

Boness: I don't know. Who testified that we couldn't do that?

OUTLINE OF ALPETCO'S PRESENTATION

OWNERSHIP

BENEFITS TO THE STATE OF ALASKA

VIABILITY OF PROJECT

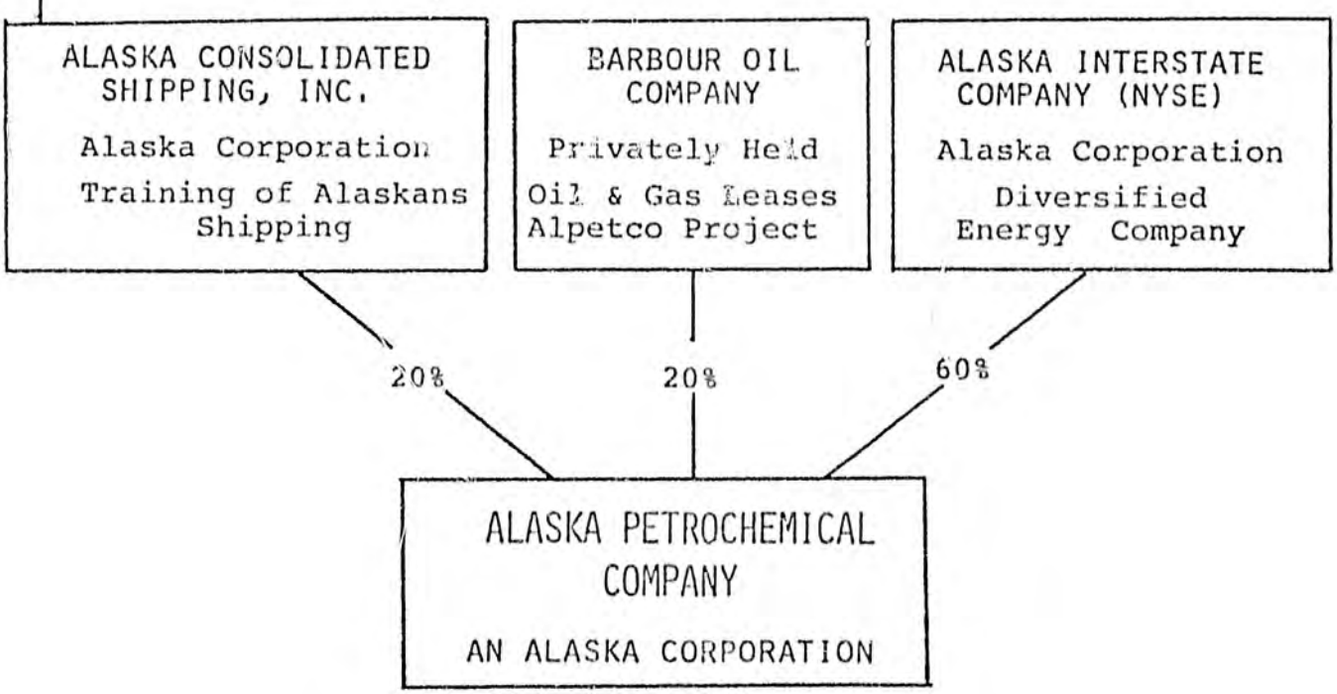
SUMMARY

MARCH 13-14, 1978

AGO 545386

OWNERSHIP OF ALPETCO

8.5%	The Aleut Corporation	
8.5%	Bristol Bay Native Corporation	
8.5%	Calista Corporation	
8.5%	Chugach Natives, Inc.	
8.5%	Cook Inlet Regional Corporation	
8.5%	Koniag Regional Native Corporation	
51.0%		
49.0%	Seatrain Lines, Inc. (NYSE)	
	Shipbuilding	Transmission-distribution of natural gas in Alaska since 1959
	Container Transport	Exploration, production and liquifaction of natural gas in Indonesia (for export to Japan)
	Ship Charter	Exploration and production of oil and natural gas in the U.S.
	Port Management	Engineering and construction of gas processing facilities
	Oil Refining	Pollution control and sulfur recovery processes
		Manufacturing



BENEFITS TO THE STATE OF ALASKA

NO RISK; NO SUBSIDY

ADDITIONAL EMPLOYMENT

ADDITIONAL TAXES

ALASKA ENDOWMENT TRUST

SHIPPING CAPABILITY

SPECIALIZED TRAINING

LOCAL HIRE

CONTROLLED INDUSTRIAL DEVELOPMENT

NO RISK TO THE STATE OF ALASKA

NO SUBSIDY

- NO PRICE CONCESSSION
- PORT, DOCKS, UTILITIES ARE INCLUDED IN ALPETCO'S CAPITAL REQUIREMENT ESTIMATES

NO INTERIM TAKE OF CRUDE

- UNLESS & UNTIL OBTAIN COMMITMENT FOR PERMANENT FINANCING
- WE HAVE OBTAINED DEPT. OF ENERGY FAVORABLE OPINION

PERFORMANCE BENCHMARKS

NO RISK TO ALASKA: PERFORMANCE BENCHMARKS

CONTRACT MAY BE CANCELLED BY STATE IF ALPETCO FAILS TO ATTAIN EACH BENCHMARK AS FOLLOWS:

TIME PERIOD	REQUIRED PERFORMANCE
1ST 6 MONTHS	MONTHLY PROGRESS REPORTS TO THE STATE
THEREAFTER	QUARTERLY PROGRESS REPORTS
6 MONTHS	$2 MILLION INVESTED SITE SELECTION BEGIN OPTIMIZATION DESIGN
12 MONTHS	$3 MILLION INVESTED
18 MONTHS	$10 MILLION COMMITTED CONTRACTS FOR SALE OF 70% OF OUTPUT GET FINANCING COMMITMENTS FOR $1.5 BILLION COMPLETE ENVIRONMENTAL IMPACT ASSESSMENT FILE FOR PERMITS FINALIZE PLANT DESIGN
24 MONTHS	$100 MILLION COMMITTED
30 MONTHS	COMMENCE CONSTRUCTION
36 MONTHS	$600 MILLION COMMITTED
48 MONTHS	$1 BILLION COMMITTED
60 MONTHS	$1.2 BILLION COMMITTED
72 MONTHS	$1.5 BILLION COMMITTED

OTHER MAJOR CONTRACT TERMS

SINCE ALPETCO'S ECONOMICS, PLANNING & FINANCING ARE BASED ON USING 150,000 BBLS/DAY,

ALPETCO WILL PURCHASE ROYALTY CRUDE UP TO 150,000 BBLS/DAY, FROM:

- 85% OF PRUDHOE ROYALTY OIL
- UP TO 70% OF OTHER ROYALTY CRUDE

  BUT ONLY IF NEEDED TO MAKE UP ANY SHORTFALL FROM PRUDHOE

  (THIS "MAKE UP" OIL IS AVAILABLE ONLY TO BRING BACK UP TO 150,000 LEVEL)

SAME "IN VALUE" PRICE, PLUS REIMBURSEMENT OF ANY COSTS STATE INCURS BY TAKING "IN KIND"

PUBLIC REFERENDUM REQURIED TO REDUCE PRICE TO BE PAID FOR ROYALTY OIL

POINT OF DELIVERY: PUMP STATION NO. 1

(STATE IS NOT A SHIPPER)

FUELS FOR IN-STATE USE OF 30,000 BBLS/DAY

ENVIRONMENTAL:

COMPLIANCE WITH FEDERAL AND STATE RULES AND REGULATIONS INCLUDING SUPPLEMENTAL STATE STANDARDS,

WHETHER OR NOT REQUIRED BY LAW

EMPLOYMENT

PRELIMINARY PLANNING ESTIMATE FOR ALPETCO

	MINIMUM	MAXIMUM
REFINERY (CONVERSION UNITS, UTILITIES, MARINE)	450	550
AROMATICS UNITS	250	300
OLEFINS STEAM CRACKER	300	375
POLYETHYLENE UNITS	400	575
POLYPROPYLENE UNITS	250	350
GENERAL WORKS MANAGEMENT	75	75
AVERAGE CONTRACT HELP	200	250
TOTAL JOBS	1,925	2,475

INCLUDED IN THE ABOVE TOTALS ARE 800 TO 950 MAINTENANCE JOBS

SUMMARY OF ADDITIONAL EMPLOYMENT

NEW JOBS:

CONSTRUCTION PHASE (3 1/2 YEARS)	3,500 - 4,000	
OPERATIONS PHASE (20 YEARS)		
PETROCHEMICAL FACILITY	1,900	2,500
SHIPPING (ACS)	250	350
TOTAL PERMANENT JOBS	2,150	2,850

A SUBSTANTIAL NUMBER OF ADDITIONAL JOBS AND ADDITIONAL BUSINESS OPPORTUNITIES WILL BE CREATED AS SUPPORT FOR THIS COMPLEX.

DIRECT TAX BENEFITS TO ALASKA*

$2.5 BILLION TAX BASE

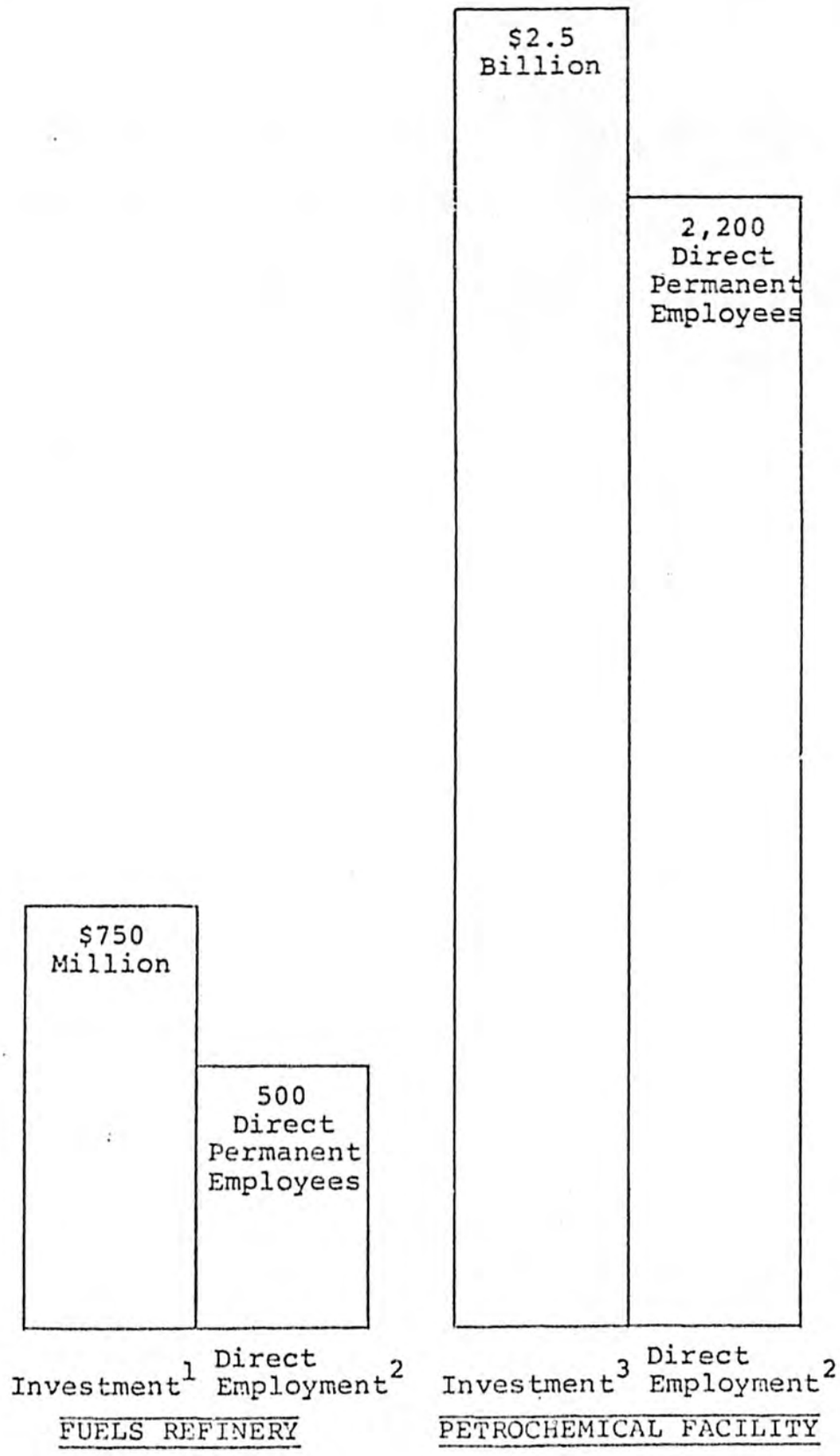
($ MILLIONS)

	ESTIMATED**	
	AVERAGE PER YEAR	TOTAL CONTRACT PERIOD
PROPERTY TAXES (@ 1%)	$ 23	$ 612
STATE CORPORATE INCOME TAX	23	632
GROSS RECEIPTS TAX	3	90
	$ 49	$1,334

*DOES NOT INCLUDE ESTIMATES OF PERSONAL INCOME TAXES PAID BY ALPETCO EMPLOYEES OR ANY TAXES PAID BY SUPPORT BUSINESSES OR EMPLOYEES OF SUPPORT BUSINESSES

**SOURCE: MARCH 10, 1978 ANALYSIS FOR THE INSTITUTE OF SOCIAL AND ECONOMIC RESEARCH

COMPARISON OF INVESTMENT (TAX BASE) AND DIRECT EMPLOYMENT TYPICAL FUELS REFINERY VS. PETROCHEMICAL FACILITY



Source: [1] Alpetco Estimate
[2] Chem Systems Inc.
[3] Alpetco Proposal

AGO 545395

ALASKA ENDOWMENT TRUST
(A CHARITABLE FOUNDATION)

PURPOSE — TO FURTHER THE

SOCIAL — CULTURAL
EDUCATIONAL — ENVIRONMENTAL

CONDITIONS IN THE STATE OF ALASKA

CONTRIBUTIONS BY ALPETCO

5% OF NET AFTER-TAX PROFITS EACH YEAR
BEGINNING 10 YEARS AFTER START-UP

ESTIMATED CONTRIBUTION:

AVERAGE PER YEAR	$10 MILLION
IN TEN YEARS	$100 MILLION

ADMINISTRATION OF THE TRUST

INDEPENDENT BOARD OF TRUSTEES
UNAFFILIATED WITH ALPETCO
APPOINTED BY THE GOVERNOR
CONFIRMED BY THE LEGISLATURE

SHIPPING CAPABILITY

ALASKA CONSOLIDATED SHIPPING IS ALPETCO'S SHIPPING ARM

WILL PROVIDE SPECIALIZED SHIPS FOR PRODUCTS MANUFACTURED

PROVIDES CAREER OPPORTUNITIES FOR ALASKAN CITIZENS IN MARITIME INDUSTRY

EXPERIENCED MANAGEMENT IN

- SHIPBUILDING
- SHIP CHARTER
- PORT OPERATIONS MANAGEMENT

MAJORITY OF ACS IS OWNED BY SIX ALASKA REGIONAL NATIVE CORPORATIONS

BACKED UP BY SEATRAIN LINES, ONE OF THE LARGEST SHIPPING COMPANIES IN U.S.

SPECIALIZED TRAINING FOR ALASKANS

ALREADY HAPPENING

SHIPPING:

HARRY LUNDEBERG SCHOOL
SEAFARER'S INTERNATIONAL UNION
PINEY POINT, MARYLAND

REFINERY:

PRIDE OIL REFINERY
SEATRAIN LINES, INC.
ABILENE, TEXAS

PLANNED

EXTENSIVE TRAINING PROGRAMS FOR ALASKANS IN:

ALL PHASES OF SHIPPING
PLANT OPERATION
PLANT MAINTENANCE

COORDINATED WITH BROWN & ROOT, CHEM SYSTEMS, ALASKA STATE OFFICIALS AND LABOR UNION OFFICIALS

LABOR POLICIES

ALASKA CONSTRUCTORS, INC.

LOCAL HIRE

TOTAL PROJECT EMPLOYMENT

- CONSTRUCTION, START-UP, OPERATIONS
- PHASING INTO PERMANENT JOBS
  - MAINTENANCE
  - OPERATIONS

CONTROLLED INDUSTRIAL DEVELOPMENT

CLEAN INDUSTRY

ENVIRONMENTALLY SAFE

HIGH CAPITAL INVESTMENT PER EMPLOYEE

ATTRACTS SIMILAR DESIRABLE INDUSTRY

The Anchorage Times, Sunday, February 19, 1978



Royalty Oil Decision

By Robert R. Richards

THIS WEEK the administration is to deliver to the Legislature its recommendation regarding disposition of the state's royalty oil.

Although several experts have questioned the viability of the four proposals before the Royalty Oil and Gas Development Board, it should be noted that the four bidders have been working closely with the state over the past few months to develop plans that make sense for all parties. Now consultants Bonner and Moore Associates Inc. have concluded that at least three of the four contenders are "fully qualified."

It seems to me that anyone concerned about the stability and long run health of Alaska's economy should give careful consideration to this marvelous opportunity to expand the vertical integration of Alaska's industrial base. Our woefull lack of in-state processing of our resources has contributed to chronic abnormal fluctuations in Alaska's economy. Expanding the manufacturing operations in Alaska will help create a more stable and therefore more socially healthy economy in Alaska.

Additionally, the petrochemical industry brings substantial benefits far beyond those of many other industries. It is highly capital intensive and one of the lowest labor intensive industry of any of our nation's basic industries. Therefore, expansion by the petrochemical industry results in very little population impact. The highly automated petrochemical operation requires very few workers and therefore imposes very little additional burden on public services, such as schools, hospitals, highways, etc.

SO IT IS very clear to see that the petrochemical industry, relative to other potential industries, imposes a very small social cost. But what about the other side of the coin? What does this industry do in the way of creating social benefits?

Again, in this regard the petrochemical industry is a star performer. Its first sociall benefit results from its employing highly skilled, well educated, and high paid employees. These people generally have a high participation rate in community affairs. Their high incomes are taxed commensurately high, and their socio-economic station in life geneally implies fewer social problems in the sense of crime, disease and the like.

The second social benefit emanating from the petrochemical industry is its contribution to creating a more stable economy. The industry is virtually non-seasonal. As we all know, those plants down on the Kenai Peninsula keep producing 365 days out of the year. Alaska's other basic industries, fishing, forest products and tourism, are highly seasonal industries. As a result typically employment in Alaska in January is one-fourth below the level of employment in July. Such seasonality creates all sorts of problems. The expansion of the petrochemical industry in Alaska will help considerably to reduce the overall seasonality of employment in our state.

ANOTHER WAY in which industry employment varies is the swings from year to year. This phenomenon, of course, is referred to as the business cycle. Again, Alaska's fishing and forest products industries are highly cyclical industries. The petrochemical industry, on the other hand, experiences considerably less cyclical fluctuation.

Therefore, the expansion of the petrochemical industry in Alaska would reduce both the seasonal and cyclical fluctuations in our economy, bringing about a considerably more stable employment situation.

The third major social benefit from the petrochemical industry results from the huge taxes and other forms of government revenue generated from this industry. The key factor here is that revenue flowing to both state and local government exceeds by far the additional burden which the industry and its employees place on state and local government. So there are all sorts of excess funds available for the pursuit of a whole array of social objectives: parks, bike paths, better schools, better health care, and on, and on and on.

This then, is what leads me to a very important conclusion which we should keep clearly in mind. It is simply this: because of the huge public revenue generated by the petroleum and petrochemical industries this type of economic growth is not only compatible with, but indeed is conducive to the pursuit of the whole array of our non-economic objectives.

Perhaps I can summarize by acknowledging the general positive relationship between our "quality of life" objectives and our economic development. Here we have the opportunity to encourage an industry which will bring wages, highly skilled, well educated people to stable employment and which manyfold more than pays it own way in terms of social impact. The social and economic attractiveness of the petrochemical industry is self-evident.

Robert R. Richards, an economist, is executive vice president of Alaska Pacific Bank.

AGO 545401

ORGANIZATION AND MANAGEMENT - DEVELOPMENT PHASE

BOARD OF DIRECTORS

O. CHARLES HONIG - CHAIRMAN
GORDON A. CAIN
W. A. ANDERSON
JOHN GUNDERSEN
WILLARD M. HANZLIK
F. HILTON LACY
SAM C. OLIPHANT
C. H. MC CALL
JAMES J. STRUPP

CHIEF EXECUTIVE OFFICER

GORDON A. CAIN

TECHNICAL

F. HILTON LACY, JR., V.P.
CHEM SYSTEMS INC.
MILLER & LENTZ, LTD.

ENGINEERING, DESIGN & CONSTRUCTION

BROWN & ROOT, INC.
GARY MONTGOMERY,
PROJECT MANAGER

MARKETING

WILLIAM STRONG
CHEM SYSTEMS INC.

FINANCE

W. A. ANDERSON, JR., V.P.
RAYMOND TROUBH
E. F. HUTTON & COMPANY
LEHMAN BROTHERS, KUHN LOEB & CO.
CHEMICAL BANK

LEGAL

EDDY ROGERS, SPECIAL COUNSEL
PAT DYER, SPECIAL COUNSEL
CATHERINE CHANDLER, ALASKA COUNSEL
JOSEPH TYDINGS, SPECIAL COUNSEL - WASHINGTON, D.C. AND JAPAN
WILLIAM VAN NESS, SPECIAL DOE COUNSEL

LEGISLATIVE AFFAIRS

HENRY PRATT
C. H. (TERRY) MC CALL, V.P.

SHIPPING

JAMES STRUPP, V.P.
ALASKA CONSOLIDATED SHIPPING, INC.

PLANNING

WILLARD HANZLIK, V.P.
ROBERT HENDERSON
ROBERT SANTOSKI
CHEM SYSTEMS, INC.

TRAINING FOR LOCAL HIRE: REFINING & SHIPPING

RONALD DAGON
SEATRAIN LINES, INC.
PRIDE REFINING, INC.

AGO 545402

CHIEF EXECUTIVE

GORDON A. CAIN

EXPERIENCE

OVER 30 YEARS IN PETROCHEMICAL INDUSTRY

RESPONSIBLE FOR

PROMOTION	STAFFING
FORMATION	MANAGEMENT

MARKET DEVELOPMENT OF
MAJOR PETROCHEMICAL FACILITIES IN

UNITED STATES	EUROPE
JAPAN	SOUTH AMERICA

CURRENT POSITIONS

PRESIDENT (AND ONE OF ORGANIZERS)

PETRO-TEX CHEMICAL CORPORATION

HOUSTON

BOARD CHAIRMAN (AND ORGANIZER)

PETROQUIMICA ARGENTINA, S.A.

BUENOS AIRES

CHEM SYSTEMS INC.

LEADING INTERNATIONAL FIRM SPECIALIZING IN MARKETING AND TECHNICAL SUPPORT OF THE PETROCHEMICAL INDUSTRY

OFFICES

NEW YORK	LONDON	MUNICH
HOUSTON	PARIS	SAO PAULO
BEIRUT		

STAFF OF 80 PROFESSIONALS

CLIENTS INCLUDE MOST OF THE WORLD'S LEADING OIL AND CHEMICAL COMPANIES, AS WELL AS SEVERAL NATIONAL GOVERNMENTS

EXPERIENCED IN PETROCHEMICAL PROJECT DEVELOPMENT WORLD WIDE, INCLUDING

UNITED STATES	JAPAN
WESTERN EUROPE	MIDDLE EAST

EXPERTS ON SUPPLY-DEMAND AND ECONOMICS OF PETROCHEMICALS

UNITED STATES

WORLD WIDE

BROWN & ROOT, INC.

OFFICES: HOUSTON AND MAJOR CITIES WORLD WIDE

ONE OF THE LARGEST AND MOST DIVERSIFIED ENGINEERING AND CONSTRUCTION COMPANIES IN THE WORLD

LARGEST VOLUME OF ANY U.S. CONSTRUCTION COMPANY LAST YEAR

SUBSIDARY OF HALLIBURTON COMPANY

1976 REVENUES = $4.9 BILLION

SHAREHOLDERS EQUITY (12-31-76) = $1.4 BILLION

EXPERIENCED IN ALASKA

NORTH SLOPE PRODUCTION FACILITY FOR B.P.

JOINT VENTURE ON 2 NORTHERN SEGMENTS OF ALYESKA PIPELINE

INDUSTRIAL COMPLEX FOR BIG-3 INDUSTRIES

EXPERIENCED IN DESIGN, ENGINEERING, CONSTRUCTION

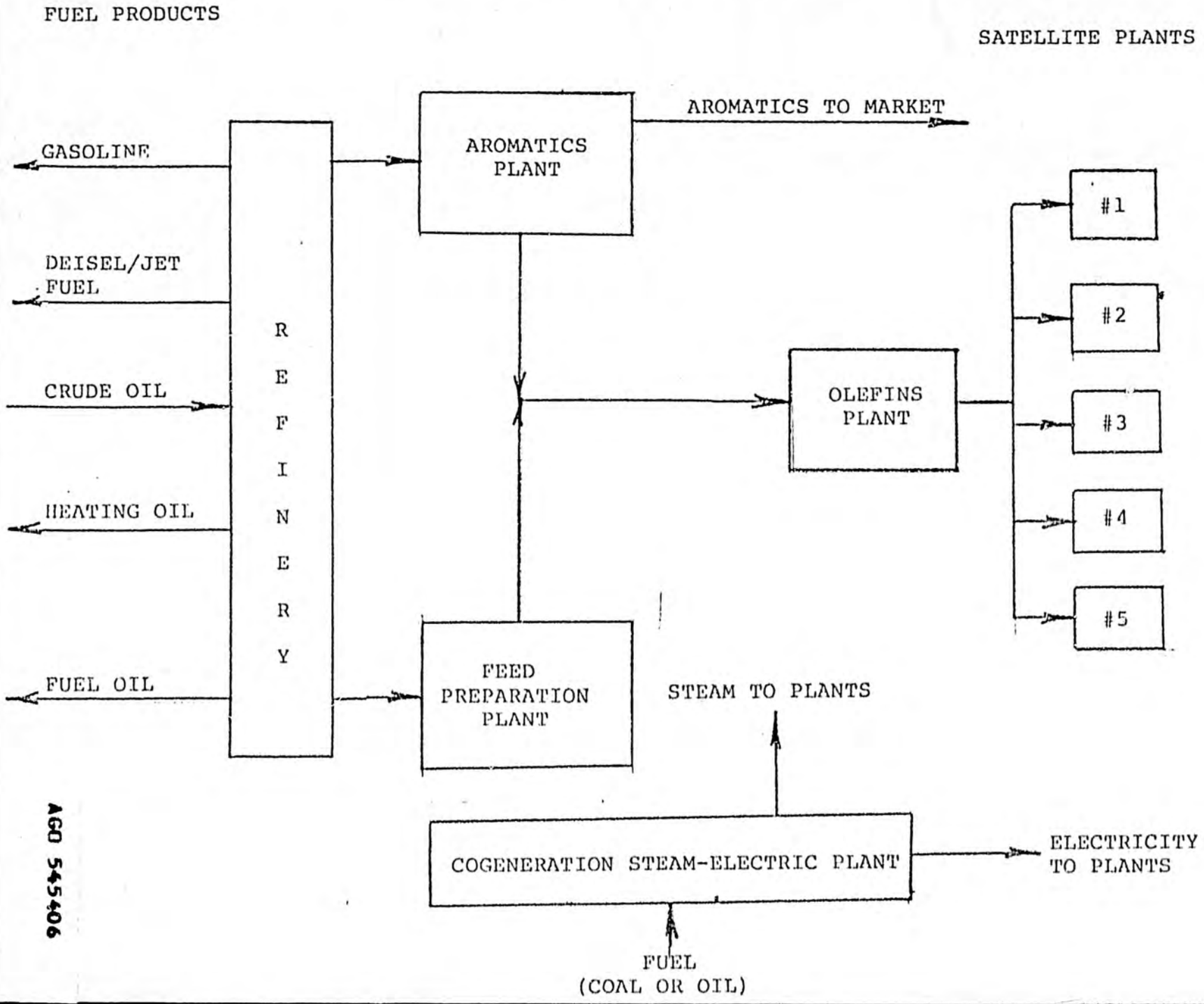
REFINING

PETROCHEMICAL FACILITIES

OFFSITES

WORKS IN ALASKA THROUGH ALASKA CONSTRUCTORS, INC., A UNION SHOP

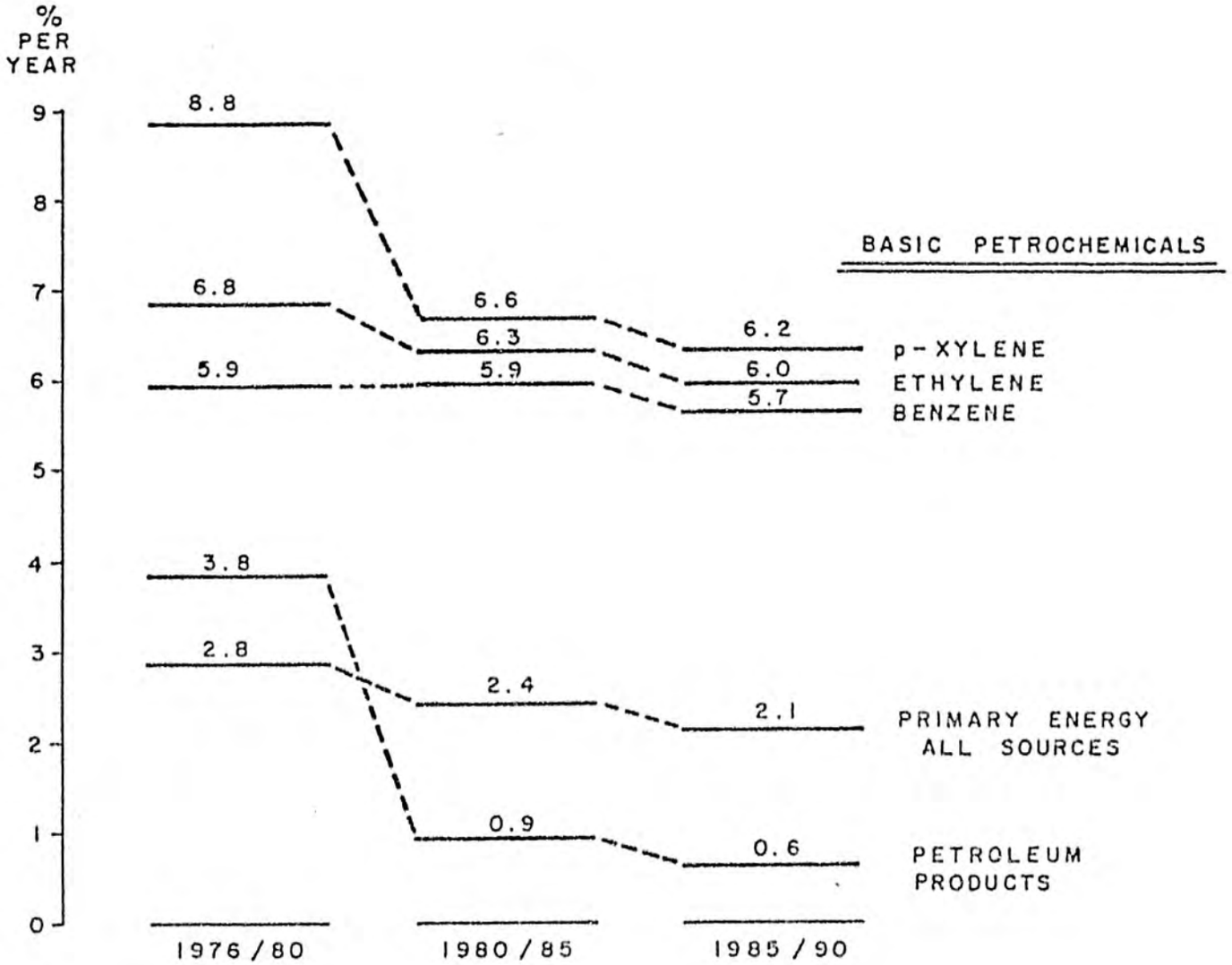
ALPETCO PROJECT



AGO 545406

FORECAST GROWTH RATES

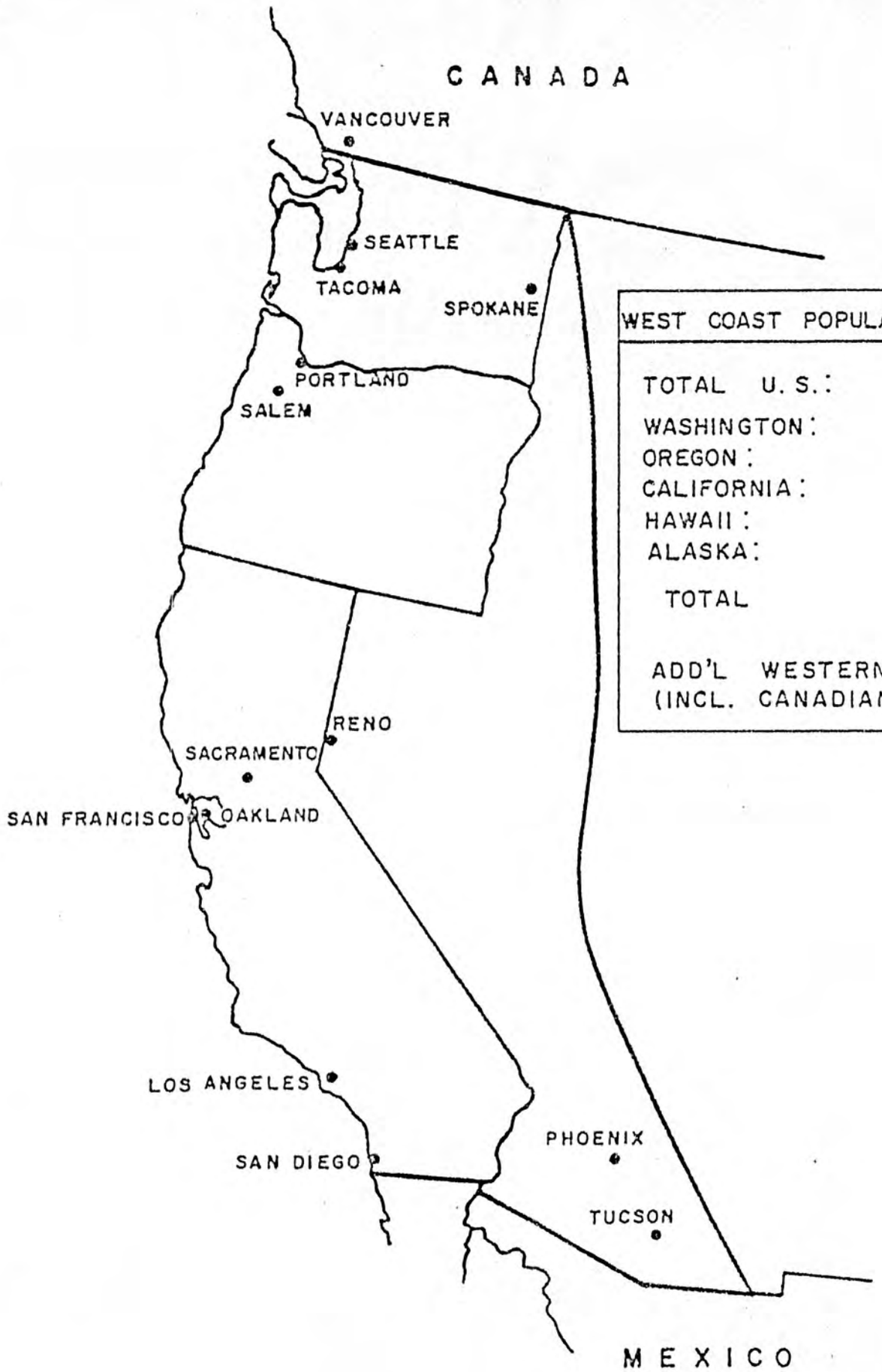
PETROCHEMICALS VS. FUELS PRODUCTS



CHEM SYSTEMS INC.

PROJECT NO. DATE

AGD 545407



WEST COAST POPULATION BREAKDOWN	
TOTAL U. S.:	213 MM
WASHINGTON:	3.5 MM
OREGON:	2.3 MM
CALIFORNIA:	21.2 MM
HAWAII:	0.9 MM
ALASKA:	0.4 MM
TOTAL	28.3
ADD'L WESTERN MARKETS (INCL. CANADIAN):	5 MM

AGO 545408

PACIFIC BASIN COUNTRIES



CHEM SYSTEMS INC.

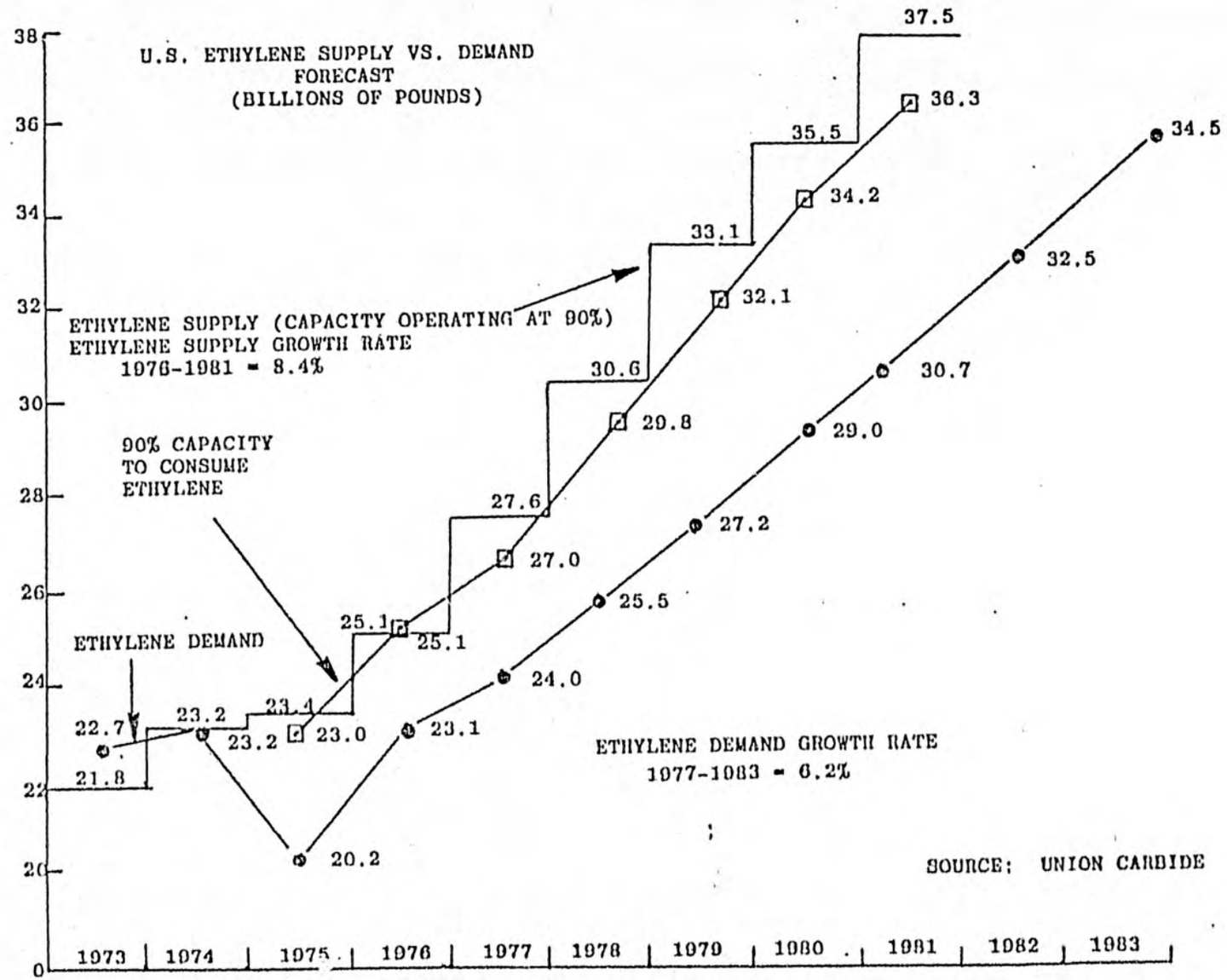
PROJECT NO. DATE

AGO 545409

FORECAST OF U.S. DEMAND FOR BASIC PETROCHEMICALS

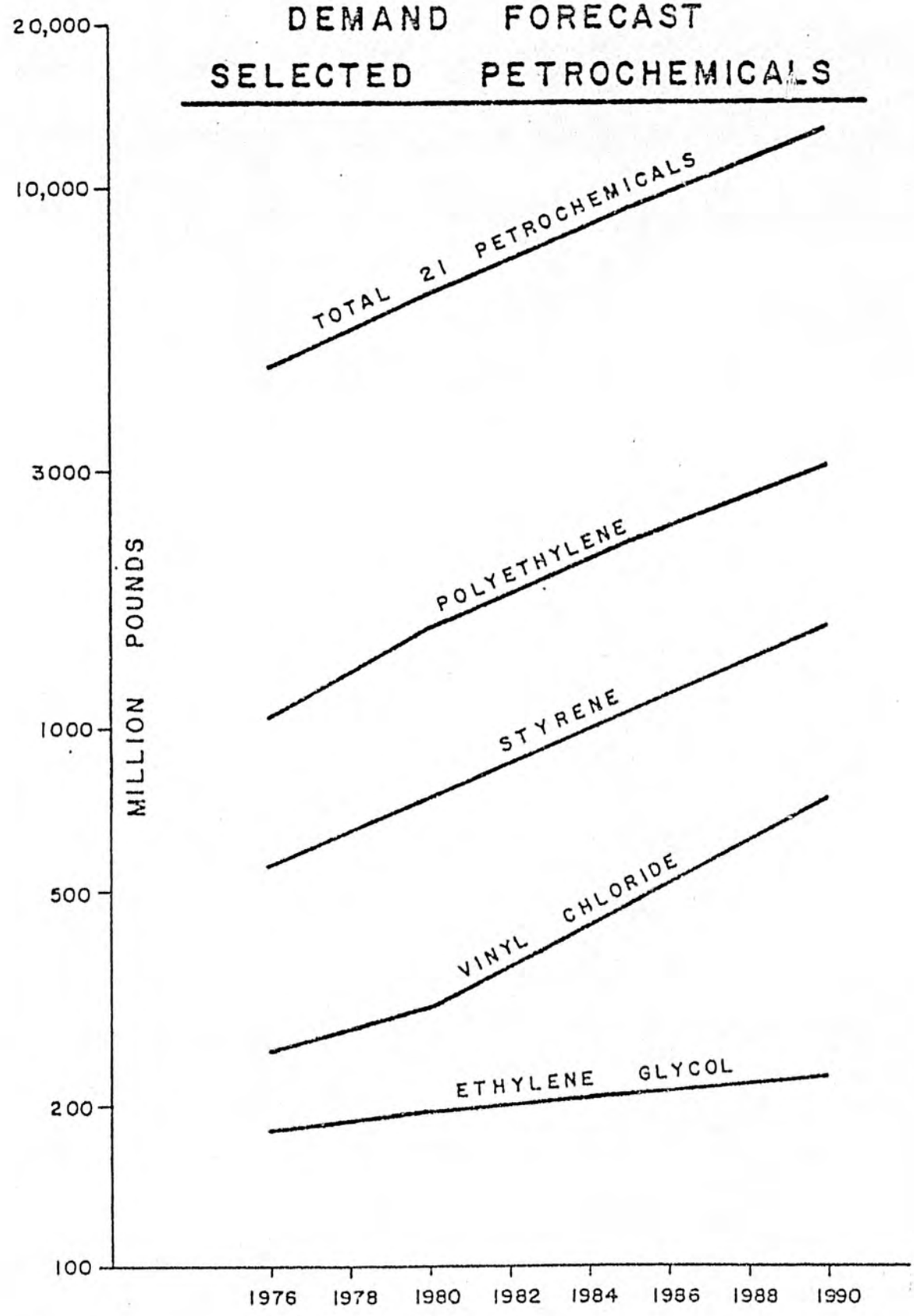
(BILLION POUNDS PER YEAR)

YEAR	ETHYLENE	PROPYLENE	BENZENE
1980	31	15	13
1990	53	28	21
2000	85	47	33
ALPETCO (CASE LE-1)	1.2	0.7	1.0


U.S. ETHYLENE SUPPLY VS. DEMAND
FORECAST
(BILLIONS OF POUNDS)
ETHYLENE SUPPLY (CAPACITY OPERATING AT 90%)
ETHYLENE SUPPLY GROWTH RATE
1976-1981 = 8.4%
90% CAPACITY
TO CONSUME
ETHYLENE
ETHYLENE DEMAND
ETHYLENE DEMAND GROWTH RATE
1977-1983 = 6.2%
SOURCE: UNION CARBIDE
38
36
34
32
30
28
26
24
22
20
0
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
21.8
22.7
23.2
23.2
23.4
23.0
25.1
25.1
27.6
27.0
30.6
29.8
33.1
32.1
35.5
34.2
37.5
36.3
20.2
23.1
24.0
25.5
27.2
29.0
30.7
32.5
34.5

AGO 545411

U.S. WEST COAST
DEMAND FORECAST
SELECTED PETROCHEMICALS



AGO 545412

CHEM SYSTEMS INC.

PROJECT NO. DATE

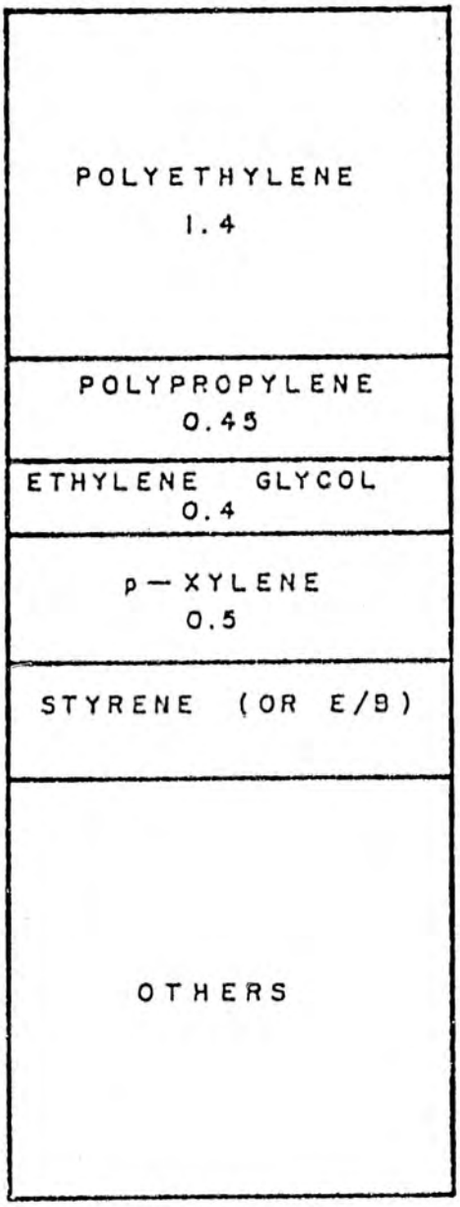
U.S. WEST COAST
SUPPLY-DEMAND
SELECTED PETROCHEMICALS

	Million Pounds			
	1976	1980	1985	1990
Ethylene for Major Derivatives				
Supply (1)	250	250	250	250
Demand	1725	2435	3455	4500
Low Density Polyethylene				
Supply (1)	120	120	120	120
Demand	710	1000	1400	1900
Styrene				
Supply (1)	0	0	0	0
Demand	555	742	1085	1590

Note:
(1) Currently installed capacity only

PACIFIC BASIN COUNTRIES
FORECAST IMPORT DEMAND
1985
SELECTED PETROCHEMICALS

19 PETROCHEMICALS
5 BILLION POUNDS



AGO 545414

CHEM SYSTEMS INC.
PROJECT NO. DATE

NEW WORLD SCALE ETHYLENE PLANTS NEEDED

	U.S. WEST COAST	OTHER PACIFIC BASIN
1976-85	3	2
1985-90	1	4
	4	6

ALPETCO INITIALLY PLANS ONE WORLD SCALE PLANT

OPPORTUNITIES TO BUILD NEW PETROCHEMICAL DERIVATIVE PLANTS (WORLD SCALE SIZE)

	For Supply To		
	U.S. West Coast	Pacific Basin Areas (Includ. Japan)	Other Markets
Low Density Polyethylene	X	X	
High Density Polyethylene	X	X	
Polypropylene		X	
Ethylene Glycol		X	
Styrene	X		
- Ethylbenzene		X	
Cumene	X		X
Paraxylene		X	
Aromatics Benzene, Toluene, Xylenes	X	X	X

ALPETCO PROJECT (CASE LE-1)

CRUDE OIL REFINERY:

FUEL PRODUCTS:	ALASKA (30,000 B/D) FUEL OILS
CHEMICAL FEEDSTOCKS:	NAPHTHA GAS OIL

PRIMARY PETROCHEMICAL FACILITIES:

AROMATICS PLANT: BENZENE, TOLUENE, XYLENE
(4% OF U.S. PLUS PACIFIC BASIN REQUIREMENTS IN 1985)

OLEFINS PLANT: ETHYLENE, PROPYLENE, BUTADIENE
(3% IN 1985)

TYPICAL DOWNSTREAM FACILITIES

PRODUCT	NORMAL MODERN PLANT SIZE	ALPETCO OUTPUT IN 1985
LOW DENSITY POLYETHYLENE	600 MM LBS/YR	4%
HIGH DENSITY POLYETHYLENE	300 MM LBS/YR	3%
POLYPROPYLENE	400 MM LBS/YR	4%
STYRENE	800 MM LBS/YR	6%

VIABILITY OF PROJECT

MANAGEMENT

DESCRIPTION AND SCOPE

MARKETING

FINANCING

MARKETING:

STRATEGIC AND POLITICAL ASPECTS

JAPAN

U.S. - WASHINGTON, D.C.

AGO 545419

VIABILITY OF PROJECT

MANAGEMENT

DESCRIPTION AND SCOPE

MARKETING

FINANCING

FINANCIAL ASPECTS

PERMANENT FINANCING

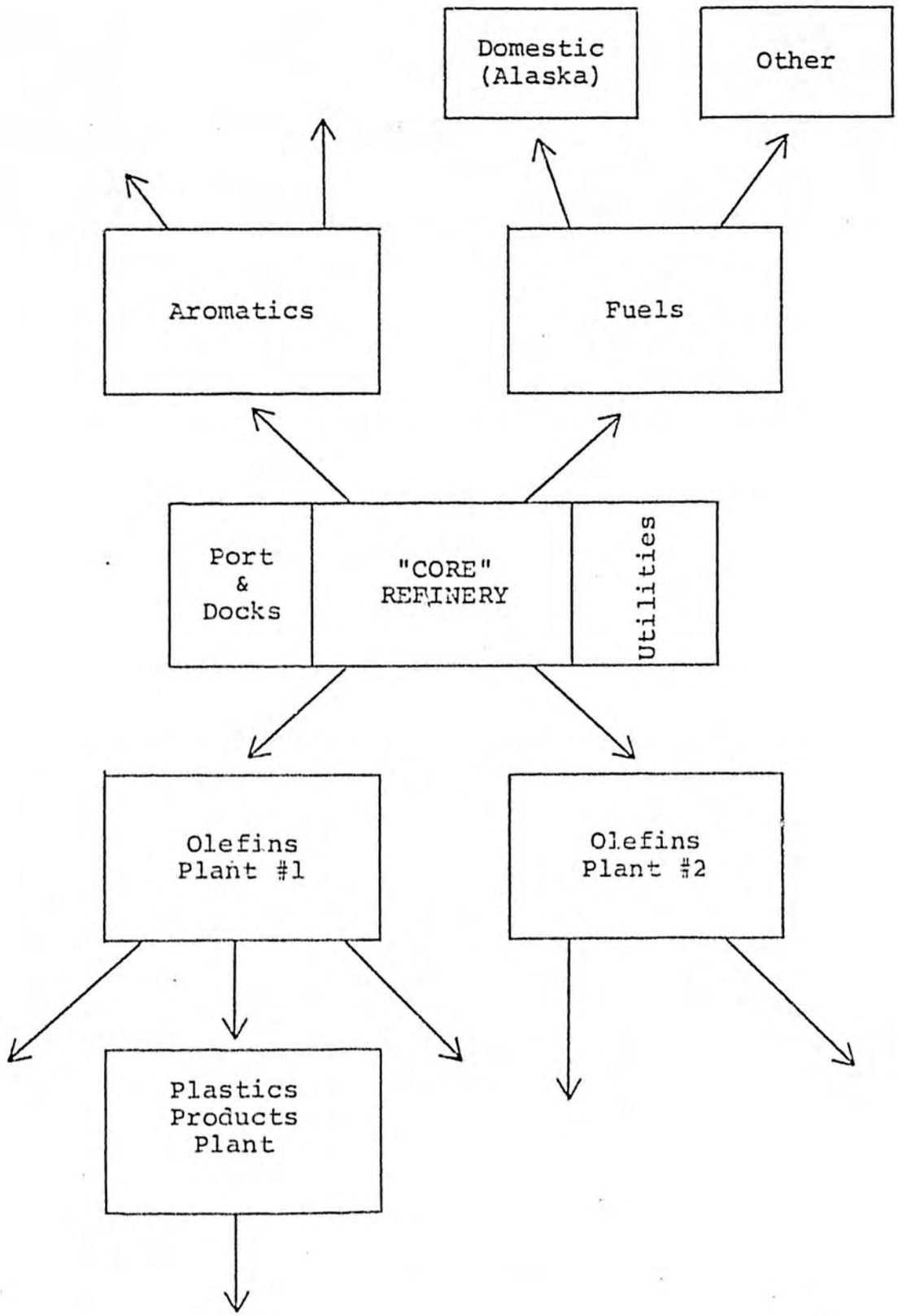
- CONVENTIONAL
- TAX EXEMPT

EQUITY

INTERIM (CONSTRUCTION) FINANCING

JOINT VENTURES

EXAMPLE OF JOINT VENTURES



AGO 545422

IN SUMMARY . . .

HIGH PROBABILITY OF SUCCESS

ALPETCO WILL HAVE CERTAIN VALUABLE ASSETS

- A LONG TERM SOURCE OF CRUDE OIL AT THE MARKET PRICE FROM A POLITICALLY STABLE REGION
- A PLAN TO PRODUCE PETROCHEMICALS FOR WHICH:
  - THE MARKET OUTLOOK IS GOOD
  - THE TIMING IS GOOD
  - THE PLANT LOCATION HAS NO GREATER NET DISADVANTAGES THAN THE OTHER LOGICAL LOCATIONS

ALPETCO PLANS TO CAPITALIZE ON THESE ASSETS BY ASSOCIATING ONE OR MORE PARTNERS WHO WILL BRING MONEY, PRODUCT OFF-TAKE AGREEMENTS, TECHNOLOGY AND PEOPLE TO THE PROJECT

SEVERAL MAJOR U.S. AND INTERNATIONAL CHEMICAL COMPANIES HAVE EXPRESSED AN INTEREST IN PARTICIPATING IN ALPETCO

ALPETCO HAS MET
THE CONTRACTUAL RECOMMENDATIONS
OF THE
STATE ENERGY POLICY COMMITTEE

1. CANCELLATION OR TERMINATION PROVISIONS
2. LOCAL TRAINING AND HIRE
3. COMPLETION OF REFINERY TIED TO SALE OF CRUDE
4. "IN-VALUE" PRICE
5. COMPLIANCE AND SECURITY PROVISIONS
6. POINT OF DELIVERY/ZERO SHIPPING LIABILITY
7. NO SUBSIDY
8. METHOD OF PAYMENT SHOULD MINIMIZE "FLOAT"
9. IN-STATE USE OF FUELS
10. IN-STATE PROCESSING REQUIRED
11. QUANTITY NOT GUARANTEED BY STATE

PETRO MARKETING SERVICES, INC.

PETROMARC

TESTIMONY BY EARL JOHNSON

BEFORE THE

SENATE SPECIAL COMMITTEE ON ROYALTY OIL AND GAS

STATE OF ALASKA

May 11, 1978

P.O. BOX 7343 • TULSA, OKLAHOMA 74105 • (918) 747-5341 AGO 545425

Senators.

Thank you for the opportunity to examine and discuss with you the pending Alpetco contract.

I have examined the Alpetco contract and numerous related reports, correspondence, news items and other data provided by the Committee.

The scope of my concern and my comments is essentially from the standpoint of effective crude oil marketing -- the area of my special expertise -- you have already heard a substantial amount of evidence on the viability of the proposed Petrochemical Facility, its effects on Alaska's economy, its risks and benefits to the state, and probably have well formed opinions on these matters.

The contract is well drawn, and does a good job of correlating a number of diverse elements into an understandable whole. There are, however, several philosophical elements that I feel need further consideration by your committee.

First, I cannot recommend the dedication of Alaska's royalty barrels to the proposed plant until, and unless the plant is completed. It certainly is absolutely necessary for any petroleum plant, especially one of the scope of the Alpetco project,

to have an assured, dependable, long-term raw material supply; but an otherwise viable plant requires such supply only when it is operational. Certainly a contract can be written which would guarantee the crude supply for such a plant when constructed, insofar as Alaska's present and future supplies of royalty oil are sufficient for such guarantees.

Absent some strategy for the use of royalty oil prior to plant completion that I have failed to consider, there appear only two ways in which Alpetco could benefit from pre-completion purchase of royalty oil. The most obvious benefit to Alpetco would be the (1) outright purchase and resale for profit of Alaska royalty oil. Given present crude market conditions in the South 48 and existing government regulations, this appears unlikely. However, with an option to purchase up to 150,000 barrels per day at a price enabling them to reach West Coast ports with North Slope crude at a delivered cost to them under $12.40 per barrel (11.45 FOB Valdez + 0.95 transportation) and with the West Coast spot market at $13.00 per barrel or more currently, the opportunity is surely open for them to offer North Slope crude at substantially discounted prices and still retain a considerable profit margin. Whether they actually sold large amounts of crude at discounted prices or not, the market price for North Slope crude would probably be reduced in West Coast markets. There would be no offsetting increase in Gulf Coast markets so

AGO 545427

that the net back on Alaskan royalty oil in value would be reduced. The foregoing situation, of course, is based on current circumstances. My original understanding of the contract was that Alpetco might selectively meet the required elements of 10.2 (1) through (3), especially 10.2(3)(d), very early after effective date, thereby advancing the triggering of paragraph 2.2, "Initiation of Deliveries," as early as 60 days after the effective date. Alpetco might then, it seemed to me, begin to take crude in the 9th or 10th month following the effective date. I have just read assurances from Mr. Honig and Governor Hammond that Alpecto would not take crude before the 25th month of the contract, and I find this reassuring.

My greater concern, however, is with the long term conditional dedication by Alaska of most of its known royalty oil. Certainly market conditions for North Slope oil today are discouraging and predictions to 1985 are pessimistic. It seems to me, however, that there are several possible ways that the market could change suddenly and unpredictably, that could greatly improve Alaska's potential for profitable in-kind marketing of its royalty oil. Alaska should weigh such possibilities very carefully before optioning its crude to others -- unless the benefits of granting such option are definite and substantial.

Some of the possible causes of "sudden and dramatic" market changes are (1) Disruption of foreign crude supplies-embargo, etc, (2) OPEC price increases, (3) Presidential imposition of a

AGO 545428

fee on foreign oil, (4) Easing of prohibition on crude sales to Japan, and (5) More sympathetic federal regulatory treatment of North Slope royalty oil.

(2) The second possible manner in which Alpetco might utilize pre-operational purchases of crude could be a time-trade arrangement with producers under which Alpetco would sell crude back to North Slope producers currently, in exchange for the right to buy similar quantities from the producers at a later date when it needs crude for actual plant operation. This appears less likely, however, than the resale of crude for profit by Alpetco.

Interesting. Why would producers want to do this in an excess profits?

With respect to market changes improving Alaska's in-kind profit potential, it will be argued that such changes would also affect the in-value price, thus increasing the price paid by Alpetco. This argument is valid unless such changes result in regulatory, transportation, or foreign exchange provisions that affect only royalty oil -- in which case in-value prices might not be affected. This would suggest some successful legal or political effort by Alaska to improve the present dissappointing price for its North Slope crude.

The issue of Alpetco's right under the contract to purchase crude prior to plant completion appears to have significant potential benefit to Alpetco, but such benefit seems to be

essentially unrelated to the successful promotion, construction and operation of the Petrochemical Facility. From Alaska's standpoint the possibility of being obligated to sell royalty oil without total assurance of the benefits calculated for successful plant operation would appear to be an indirect subsidy to the project, and could very well result in lower long-term net back to the State from its royalty oil sales. I believe that the concept of Alaska furnishing royalty oil to supply a plant such as Alpetco's is solid -- but only if the plant is one that can be financed and built based on its own economics, with the state agreeing to furnish the crude at competitive prices to supply the plant, beginning with its completion and commencement of operations.

I am still troubled by the lack of precise definition of "commit" and "commitment" as used in the contract, especially in Alpetco's benchmark requirements in paragraph 10.2. Again, Mr. Honig's letter of May 8, 1978, is somewhat reassuring in its statement that Alpetco's intended meaning of "commit to expend" means "contracturally binding agreements, contracts, and purchase orders." My remaining concern, however, is that in practice such agreements, contracts, and purchase orders are conditional, and subject to change or cancellation. Since the dedication of so much of Alaska's future production hinges on interpretation of the one word "commit," the legislature must at least assure itself of a firm and narrow interpretation by the commissioner with respect to all benchmark requirements.

There are a few technical concerns that I feel need comment. These are of less significance but should be considered.

1. The contract never states how much of the state's royalty oil will be utilized in the plant. Generally, the inference seems to be that if the plant is built, then it will process all of the royalty oil purchased. However, paragraph 4.3 is in direct conflict with that concept in that it provides, in part, "If buyer does not use the royalty oil sold and delivered hereunder or traded or exchanged oil in the Petrochemical Facility..." Indeed, if buyer does not use royalty oil or traded or exchanged oil, then what might he use, and with what effect on the State?

2. Paragraph 2.0 provides that seller shall have the right to use the remaining 15% of its crude in any way that it wishes, but paragraph 8.3 provides that state will sell "minimum" quantities of oil in value in order to provide for contract price determination. These two provisions contradict one another, and they raise the more important question -- how little crude can the state sell in value and thereby receive an accurate in value price in the contract? Are there restrictions on the minimum?

3. Paragraph 12.1: In providing for security interest credit protection for the state, I am compelled to comment that the procedures thereunder will turn out to be extremely

AGO 545431

complex. As a crude seller, I would have much preferred the bond or L.C. concept. Additionally, is the $50,000,000 capital and surplus provision adequate for a bank to issue a letter of credit for, say, 60 days runs at 150,000 barrels/day at $6.00 per barrel?

6
150 M
60 days

4. Paragraph 15.2 (Force Majeure). Item (ix) provides that inability to obtain federal, state, or other government permits or licenses shall be regarded as a force majeure, and could hold the contract in limbo for up to four years (longer if state permits are the force majeure item). Presumably, Alpetco could be receiving royalty oil during any such delay.

In closing, I should like to state very clearly, that I would like to see the Alpetco project succeed -- for Alaska's benefit. My expressions of concern herein are genuine, and the result of my best effort to evaluate the contract as I see it -- from a crude oil marketing standpoint. Time for study and preparation has been short, and the subject is complex.

I shall be happy to answer questions directly or indirectly related to my testimony today -- either now or later, in writing.

AGO 545432

Monday

1. ALPETCO Presentation

Essentially the same as given to the Royalty Board on 2/21/78, a copy of which is attached.

Expansion on their previous presentation was in the following areas:

- Rising trend of using oil as feedstock for new petrochemical plants.
- Japanese and U.S. mutual interests in having the Japanese involved either as takers of products or as participants in joint venture undertakings.
- The ability to overcome the "Alaska disadvantage" if ALPETCO runs their facility at 10 percent higher capacity than lower 48 plants, which they expect to do with the assured supply.
- Want gas liquids if they become available.
  Will design their cracking unit to accommodate gas liquids.
  Believe that demand will be such by the time their plant comes on stream that if one plant is feasible, so are two.

Questions and Answers revolved mainly around:

- Volume: Percentage vs. specific amount.
- Alaska Disadvantage: Seize an opportunity to see if it is viable here vs. assured supply.
- Japanese Interest: Security of stable supply.
- Local Hire

Alaska State Legislature

POUCH V, STATE CAPITOL
JUNEAU, ALASKA 99811
907 465-3800

TRANSCRIPT OF TESTIMONY OF

ALPETCO

March 13, 1978

BEFORE THE SPECIAL COMMITTEE ON ROYALTY OIL AND GAS

Committee:

Senators:
Chairman Mike Colletta
Pat Rodey
Bill Sumner
John Sackett
Kay Poland

Representatives:
Chairman Bill Miles
Charley Parr
Chat Chatterton
Joe McKinnon
Al Osterback

CHAIRMAN: The Senate Panel of the Special Committee that was appointed for review and evaluation of the Governor's Resolution dealing with the sale of the State's royalty oil. The other members of the committee to my immediate right, Senator Kay Poland, Senator Bill Sumner, Senator John Sackett and Senator Pat Rodey. The House likewise constituted a committee and that's chaired by Representative Bill Miles who will introduce his own people. It's at least the intent of the Senate Panel for these first two days of hearings that they're nothing more than informational hearings to acquaint us with what has transpired by the successful, or tentative successfully award winner, and the State's position as to why that specific company or group of companies was selected. The Senate side most definitely comes in with a little bit of a disadvantage insofar as that Representative Miles' committee has had activity in the interim in this area so an apology before (cough-indisc) if meetings do not seem to generate the type of enthusiasm as some might hope. Bear with us, it's only the first two we're going to become acquainted with what has transpired. With that Representative Bill Miles can introduce his people.

CHAIRMAN BILL MILES:

AGO 545509

Thank you Senator Colletta. I'm Bill Miles and to your right is Senator, or Representative Charley Parr and Representative Chat Chatterton. I certainly want to concur with the opening comments made by Senator Colletta as I think as our intent we have, at least I have spent a good deal of time working

with the contracts to listen to your presentation gentlemen, ladies and gentlemen, from ALPETCO, and then we would like to ask some questions at this time but certainly would like you to take the full amount of time for whatever presentation you have prepared. Because of the time constraints that may force us to back up possibly tomorrow, we could have some of you gentlemen back to answer additional questions that may be raised. The House plans to continue its hearings on the royalty oil contract Wednesday and Thursday evenings, I think everybody's (indisc). There's plenty of agendas floating around, if you haven't had one I'll see that you get one. And if necessary, on Saturday. We're intending to raise a number of questions so that we can get as much information as possible. The Governor's urged us to act expeditiously on the contract and we're going to attempt to comply because we asked him first to act expeditiously and hence, if there are some questions that can't be answered we will try to put them in writing beginning of next week in an attempt they can be answered within 7-10 days in writing. And with that unless you have additional opening comments Senator, we will turn it over to the representatives from ALPETCO. If you will please introduce yourself and your representatives and we'll begin.

MR. CHARLES HONIG:

I'm Charles Honig, Chairman of Alaska Petrochemical Company and I will preside during our presentation and I think it would be more appropriate Mr. Chairman if we introduce the people as they participate in the presentation, if that's agreeable.

CHAIRMAN: Your Pleasure.

MR. CHARLES HONIG:

Mr. Chairman and Committee Members, no business endeavor is stronger than or better than the people associated with it. From its beginning ALPETCO has associated world-recognized specialists and experts in each aspect of our proposal. These people are dedicated and will continue to work with us as we go forward. They have been with us in most parts of your state and met with the Royalty Board at many locations. We're here to answer any questions on any aspect of this project and if we cannot answer them as Chairman Miles suggested, we will get the answer as soon as possible. We've agreed to spend our time and effort and money to fulfill this contract because it will be a profitable business venture and we're interested in profits. The State of Alaska will incur no risk nor lose any money in the process. When we succeed, your gain will be substantial and it will be permanent. I'd like to just project some slides if I may to illustrate what we would like to talk about today. We'd like to talk about the ownership of our company, the benefits to the State of Alaska, the viability of the project, and then summarize.

The ownership of Alaska Petrochemical and it's better if we start at the bottom of the chart and go up, as you can see there are three stockholders of ALPETCO: Alaska Consolidated Shipping, Barbour Oil and Alaska Interstate. Alaska Consolidated Shipping owns 20%, Barbour Oil Company, which is a privately-held family company, owns 20%, and Alaska Interstate which is a listed company, owns 60%. Alaska Consolidated Shipping is made up of seven stockholders. The first six listed are, Alaska Native Regional Corporations, which each own 8-1/2% of Alaska Consolidated Shipping. Collectively they own control of that company. Forty-nine percent of ACS, as we call it, is owned by Seatrain Lines, Inc. (ph), also a New York stock exchange listed company engaged in the function shown on the chart. Barbour Oil Company provided the leader of this project in its early phases and whose untimely death we all regretted, because he was a real driver of the project and that was John Barbour. And in honor of John's efforts, we would like to dedicate and name this refinery the Barbour Refinery. Alaska Interstate is an Alaska Corporation, has always been an Alaska Corporation, and consists primarily of the gas transmission and distribution company in Anchorage and Kenai because it was formed right after Alaska became a state in 1959. We're engaged also in exploration production of liquefaction of natural gas in Indonesia which is currently being exported, liquefied and exported to Japan. We're engaged in exploration and production of oil and gas in the U.S. We have an engineering and construction company in the gas processing facilities area which has been in business since 1946, and we're also engaged in pollution control, sulphur recovery processes and manufacturing. So those are the owners of Alaska Petrochemical, the only owners.

Let's talk a moment about benefits to the State of Alaska. We'd like to discuss those listed here. No risk. No subsidy. Additional employment. Additional taxes. The Alaska endowment trust. Shipping capability. Specialized training. Local hire. And controlled industrial development.

First the no risk, no subsidy. Our contract provides no subsidy to ALPETCO. There are no price concessions. We included in our capital requirements all of what are called the off-site facilities, such as ports, docks, utilities. We agreed that we would take no interim crude, no crude during the time the refinery is being put together unless and until we have obtained a commitment for the permanent financing. And once we've obtained that then the contract permits us to take crude on the interim basis, because once the commitment is obtained then everyone can be assured the project is going forward. We obtained from the Department of Energy a favorable opinion which protects the State of Alaska, if we do take crude on an interim basis, and merely provides that an exception in effect so that Alaska can take back the crude even if we have purchased some in the interim. Probably the most important

no risk area that is provided in the contract is what we call performance benchmarks. And those benchmarks provide that the contract may be canceled by the state if ALPETCO fails to obtain each benchmark in the contract and here is a summary of those. During the first six months after ratification of the contract we must give monthly progress reports to the state, thereafter, quarterly reports. Six months from the time the contract is effective, we must have invested at least 2 million dollars. We must have informed the state of our site selection, and we must have begun the optimization design of the Petrochemical facility. Within 12 months we must have invested at least 3 million dollars. The 18 months time period or benchmark is probably the most important, most subsidy of all, it not only requires that we must have committed at least 10 million dollars but more significantly it requires that we must have contracts for the sale of at least 70% of the products the plant would make and we must have obtained financing commitments for at least 1.5 billion dollars, both permanent and interim construction commitments. It provides we must have completed our BIA and we must have filed for permits and finalize plant design. So that's why I said earlier if we make the 18 month benchmark which involves getting financing commitments, then the project is assured of going forward. Then we have additional benchmarks at 24 months on up to 72 months and except for the 30 month one which says we must commence construction by then, the others relate to money and indicate the minimum amount we must have committed to spend by those times, the last one being 72 months we must have committed to invest at least 1.5 billion dollars. So those are the benchmarks for performance provided in the contract. There are provisions for some extensions of time by the state up to, I believe, a maximum of 6 months, pertaining to some of those requirements.

The other major contract items, our economics, our planning, our financing, are based on using 150,000 barrels of crude oil per day. We will purchase that royalty -- that as royalty crude up to that amount of 150,000 barrels per day. It will come first from and then maybe all from up to 85% of Prudhoe Royalty Oil. The state wanted to retain initially 10% and later 15% because of North Pole Refinery of the Prudhoe Royalty Oil and would sell us no more than 85%, because that's less than 100 and because we are dedicating about 2.5 billion dollars to a on-the-ground facility in Alaska. It is essential that we have the 150,000 barrels a day as a feed stock. So in the event that we are not receiving at least 145,000 barrels a day, for as long as a 2-month consecutive period, we may then ask the state to sell us royalty crude from locations other than Prudhoe Bay, but only if we need it to make up that short fall, and then only up to but not to exceed, 70% of such royalty crude. The state insisted on reserving and keeping 30% of that royalty crude which we would not have a right to ask for. So that is simply make-up oil and it is available only to bring us back up to the 150,000 barrel a day limit.

The contract also provides that we will pay the same in-value price that the state would receive had it not sold the oil to us. In addition to that, should the state incur any expenses in connection with making a sale to us in kind, we have agreed to pay those additional costs.

The next item is--requires a public referendum in the event that we request any reduction in price that we would pay, anything, any request for price below the in-value would have to be voted on--would have to not only be acted on by the Legislature but would have to require a public referendum to approve any price concession. We agreed to the point of delivery after long negotiation and we agreed that it would be Pump Station No. 1 so that the State of Alaska does not become a shipper, which it did not want to do. We agreed that we would provide up to 30,000 barrels a day of fuels for in-state use, Arctic fuels, other fuels for use in Alaska. Environmentally, we agreed to comply with Federal and State rules and regulations including all supplemental state standards whether or not those supplemental standards are required by law. We agreed we would observe them even if some of those being contested currently are not upheld. Those are the principle major contract terms.

I'd like to ask Willard Hanzlik who's the Vice-President with ALPETCO and Alaska Interstate if he would talk about additional employment and additional taxes among the benefits, Willard.

MR. WILLARD HANZLIK:

The next item on our list of benefits to the state is additional employment. We believe it is one of the most important contributions that this project can bring to the State of Alaska for employment in this industry. Refining and petrochemical industry represents permanent employment, it is non-seasonal, it is not (indisc), it is permanent, and it creates because of the diversity of the different jobs available in the manufacturing process, opportunities for workers to upgrade their skills and to have careers that develop within the industry. On a preliminary planning basis, our experts who are experienced in the organization and operation of facilities such as the one we contemplate, have indicated that these are the types of jobs for the various refinery units listed on the left which will be needed when this project is brought into operation. We have shown minimums and maximums because at this point in time it is literally impossible to determine precisely the number of employees that will be required. However, the range of 1,900 to 2,500 is a fair range and representative of the number of permanent operating and maintenance employees that will be required by a facility such as this. This does not include the support employees which would--the jobs which would be created in the community to support the facility.

To summarize the--those other jobs and total employment picture, during the construction phase which is expected to last approximately 3-1/2 years, a range of between--an average of between 3,500 and 4,000 construction employees will be required by the project. Now those numbers will not land all simultaneously to start the project for of those there will be a build-up and many of the employees which will be in the construction phase of the project will certainly be qualified and have the skills needed to remain and become permanent members of the community and become operating and maintenance employees. To summarize, in the operating phase, the long-term phase of the project, the 1,900 to 2,500 range which I talked about earlier, plus the shipping requirements of the project which would be conducted by our affiliate, Alaska Consolidated Shipping, would require another 250 to 350 jobs and these would be permanent maritime jobs will be discussed later in the presentation. So we are talking about a total of 2,100 to 2,800 permanent jobs. Now this does not include the multiplier of additional jobs which would be needed in the community and those are estimated from 3 to 4 or 5 times so you are talking about a range of 6 to 10 thousand new permanent jobs.

As far as taxes go a project such as this provides a substantial tax base for local and state government because of the considerable amount of capital investment based on a 2.5 billion dollar facility which is what this facility will be ultimately, and based on the projections which we have--are submitting today to the Institute of Social&Economical Research at their request, these are the tax numbers which are--result from the project. On an average year after the project is in operation, talking about a total of 49 million dollars a year. In additional, these are incremental taxes to the State of Alaska, through the property tax structure, through state corporate income tax and through gross receipt tax. Over the total contract period of a 27-year period. The project is for over 1 billion dollars of additional state and local taxes. One way tolook at the comparison between a facility which is designed for the manufacture of petrochemicals versus a facility that is designed for the processing of crude oil into fuels products, is simply to look on a relative-comparison basis and on the same scale is the two bars on the left side represent an average or a typical fuels configured facility (indisc.-cough) which is to be built in Alaska which would cost with all the support structures and utilities and docks and ports, etc. around 750 million and is estimated at about 500 direct permanent employees would be required to operate that facility. The facility which ALPETCO proposes and which would cost 2.5 billion dollars is shown to be substantially greater in terms of the assests invested, therefore the tax base and also the number of employees is substantially greater, several times greater in fact. Mr. Honig.

MR. HONIG: Thank you Willard.

Another benefit to the State of Alaska and provided for in the contract is what we call the Alaska Endowment Trust which

is a charitable foundation and the purpose of this trust would be to further the social, educational, cultural, environmental conditions in the State of Alaska. It would be funded by contributions made by ALPETCO beginning after the operation had been in--after we'd been in operation for 10 years and it would be equal to 5% of the net after tax profit beginning with the 11th year after start up. We estimate the average contribution would be 10 million dollars per year and for 10 years that would be roughly 100 million dollars. The trust would be administered by an independent board of trustees unaffiliated with ALPETCO appointed by the Governor and confirmed by the Legislature. Another benefit involves shipping and training of Alaskans and I would like to ask Jim Strupp who is the Vice-President of ALPETCO and also the Vice-President of ACS if he will discuss those subjects, Jim.

MR. JIM STRUPP:

Thank you Charles. Alaska Consolidated Shipping will act as ALPETCO's shipping arm, will act as it's shipping arm in several ways. Because of the lead time between ratification of the contract and actual commencement of actual product shipment, we will have enough time to complete new buildings and provide specialized ships for the product movements and this should give us a very, very good optimization from a shipping cost standpoint. Mr. Hanzlik indicated before, we will also provide (indisc) opportunities for Alaskan citizens in the maritime industry, those jobs should approximate 250 to 350 full-time maritime jobs. Alaska Consolidated Shipping has experienced management in ship building, seatrain lines, one of the members of that company is in the ship building business and currently employs 620 employees building tankers as well as other vessels. We have experience in the ship chartering business, manage and charter over 25 vessels at this time and also are experienced in port management, both in the United States and overseas. As you may know, the majority of Alaska Consolidated Shipping is owned by six Alaska Regional Native Corporations, Koniag (ph), Cook Inlet, Aleut Corporation, Bristol Bay, Chulista (ph) and Chugach. And that's backed up by Seatrain Lines, one of the largest shipping companies in the United States.

I'd like to talk now about specialized training for Alaskans. I've kind of broken this down into two phases, that which is already happening and that which is planned. The already happening category, several months ago John Gunderson who is also a director of ALPETCO and a member of the Aleut Corporation, I traveled to Piny Point (ph), Maryland and met with officials of the Harry Lundberg (ph) School Seafarers International Union there. At that time we made arrangements for the beginnings of training programs for Alaskans and currently we have two students from Alaska attending that program, Mr. Ray Klack (ph) who is a member of the Doyon Regional Native Corporation, Mr. Fred Haas (ph) of the Cook Inlet Corporation. They are enrolled in a 3-month basic seaman course and are guaranteed employment upon leaving. The school pays for the total cost of their training, Alaska

Consolidated pays for their transportation to the school. They have indicated to us that they will be more than happy to take in each of their classes several Alaskan citizens as we proceed. We've also made some training program scheduling at our Pride Oil Refinery, which is located--which is owned by Seatrain Lines and located in Abilene, Texas. We felt that it was important to begin schooling of Natives, Alaskan citizens in the basic refinery techniques. We have currently down there in a job rotation program, they've been there for the last 2-1/2 to 3 months, Mr. R. C. Credo Jr. (ph), of the Sealaska Native Corporation, and Mr. Lauren J. Hoight (ph) of Cook Inlet. They'll be asked to come back to Alaska once they complete their training and work with us in additional recruitment programs and development of our planned training programs down the road.

We are also planning extensive training programs for Alaskans in all phases of shipping, and plant operation, plant maintenance. These will be in depth programs conducted here in Alaska and outside depending on the area of expertise needed and these programs will be coordinated with the help of Brown and Root, Chem Systems (ph), Alaska state officials, and labor union officials. With that I would like to turn it back to Charles.

MR. HONIG: Thank you Jim.

Next we'd like to hear from a Senior Vice-President of Brown and Root who's been working with us since the beginning of this project and that's Jimmy Norris from Brown and Root. I might tell you a little about his company that he might be too modest to mention. Most of you probably know that Brown and Root operates world-to-wide, it's one of the largest and most diversified engineering and construction companies in the world. Last year I think it had the largest volume of any U.S. construction company. It's a subsidiary of Hal of Burton (ph) which in 1976 had almost 5 billion dollars in revenues and it has a shareholders equity of approximately 1-1/2 billion dollars. It's experienced in Alaska, it built the production facility for BP on the North Slope, it was a joint venture in two northern segements of the Alyeska Pipeline, it's currently building an industrial complex for the big three industries in Alaska. It's experienced in design engineering construction of refineries, petrochemical facilities and off-site facilities. And in Alaska it works through Alaska Constructors which is a union shop company. Jimmy would you like to talk some about the labor policies we will follow.

MR. JAMES C. NORRIS:

Thank you Charles. Since most of the work that we would do is out in front of us, sometime after hopefully you gentlemen see fit to ratify this contract. We will speak briefly of two areas: labor policies would be the first one. The work that Brown and Root does in Alaska would be done through its subsidiary, Alaska Constructors, with headquarters in Anchorage. Construction would be by Alaskan workers insofar as possible. We would maximize the employment of Alaskans. We would do everything possible to work with the local unions and with the Alaskan government to train Alaskan workers using techniques that are already established. I think Mr. Hanzlik mentioned awhile ago that we're looking at 3,500 to 4,000 average construction employees for a3-1/2 year period. Many of these people can be trained as permanent employees as plant operators and maintenance personnel.

What we want to offer you gentlemen is a clean industry, environmentally safe plant, it's a controlled industrial environment. It's a plant that I have seen over 30 years in Houston, I have watched the growth of the Houston Petrochemical facilities in the Houston area for that length of time. We can say now that in Galveston Bay, which is adjacent to the ship channel, that there is essentially no pollution. It's an area that's good to fishermen, sports fishermen and commercial. It's good to the residential people, it's good to the government, the Manned Space Crafts--. Manned Space Craft Center is just nearby. All of these people live together harmoniously and the petrochemical industry is the biggest--one of the biggest employees of people in the Houston area. As a--I guess something that is indicative of the pollution-free environment is that last week I read something published by the State of Texas that 1977 was a record year for one of our delicacies which is the Blue Crab. Some 7 million pounds came right out of Galveston Bay where all of these petrochemical industries are.

Finally, we want to say that this is a highly capital intensive facility. It's a very sophisticated type of industry and it's also very synergistic. What it's going to do, it will attract other petrochemical facilities to this one as well as what you call the downstream plants which manufacture the polyethylene.. film and the bottles and such things that you would have from plastics. Thank you.

MR. HONIG: Thank you Jim.

One final point on the matter on economic and social aspects, I'd like to read an editorial that appeared in the Anchorage Times on Sunday, February 19, written by Bob Richards who is the Economist and Executive Vice-President of the Alaska Pacific Bank, because it is particularly good in summarizing

what we've been talking about here. It reads as follows:

This week the administration is to deliver to the Legislature its recommendation regarding disposition of the state's royalty oil. Although several experts have questioned the viability of the four proposals before the Royalty Oil and Gas Development Board, it should be noted that the four bidders have been working closely with the state over the past few months to develop plans that make sense for all parties. Now consultants, Bonner and Moore, Associates, Inc., have concluded that at least three of the four contenders are fully qualified.

It seems to me that anyone concerned about the stability and long run health of Alaska's economy should give careful consideration to this marvelous opportunity to expand the vertical integration of Alaska's industrial base. Our willful act of in-state processing of our resources has contributed to chronic, abnormal fluctuations in Alaska's economy. Expanding the manufacturing operations in Alaska will help create a more stable and, therefore, more socially healthy economy in Alaska. Additionally, the ptetrochemical industry brings substantial benefits far beyond those of many other industries. It is highly capital intensive and one of the lowest labor intensive industries of any of our nations basic industries. Therefore, expansion by the petrochemical industry results in very little population impact. The highly automated petrochemical operation requires very few workers and therefore imposes very little additional burden on public services such as schools, hospitals, highways, and so forth. So it is very clear to see that the petrochemical industry relative to other potential industries, imposes a very small social cost.

But what about the other side of the coin? What does this industry do in the way of creating social benefits? Again, in this regard the petrochemical industry is a star performer. Its first social benefit results from its employing highly skilled, well educated, and highly paid employees. These people generally have a high participation rate in community affairs. Their high incomes are taxed commensurately high, and their socioeconomic station in life generally implies fewer social problems in the sense of crime, disease, and the like.

The second social benefit emminates from the petrochemical industry is its contribution to creating a more stable economy. The industry is virtually non-seasonal; as we all know those plants down on the Kenai Peninsula keep producing 365 days out of the year. Alaska's other basic industries fishing, forest products, and tourism, are highly seasonal industries. As a result, typically, employment in Alaska in January is one-fourth below the level of employment in July. Such seasonality creates all sorts of problems. The expansion of the petrochemical industry in Alaska will help considerably to reduce the overall seasonality of employment in our state. Another way in which industry employment varies is it swings from year to year.

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This phenomenon of course, is referred to as the business cycle. Again, Alaska's fishing and forest products industries are highly cyclical industries. Petrochemical industry, on the other hand, experiences considerably less cyclical fluctuation. Therefore, the expansion of the petrochemical industry in Alaska would reduce both the seasonal and cyclical fluctuations in our economy bringing about a considerably more stable employment situation.

The third major social benefit from the petrochemical industry results from the huge taxes and other forms of government revenue generated from this industry. The key factor here is that revenue flowing to both state and local government exceeds by far the additional burden which the industry and its employees place on state and local government. So there are all sorts of excess funds available for the pursuit of a whole array of social objectives, parks, bike paths, better schools, better health care, and on and on and on. This then is what leads me to a very important conclusion which we should keep clearly in mind. It is simply this--because of the huge public revenue generated by the petroleum and petrochemical industries, this type of economic growth is not only compatible with but indeed is conducive to the pursuit of the whole array of our non-economic objectives.

Perhaps I can summarize by acknowledging the general positive relationship between our quality of life objectives and our economic development. Here we have the opportunity to encourage an industry which will bring wages, highly skilled, well-educated people to stable employment and which many fold more than pays its own way in terms of social impact. The social and economic attractiveness of the petrochemical industry is self-evident. So we've discussed these benefits to the State of Alaska -- no risk, no subsidy, additional employment, additional taxes, the Alaskan Endowment Trust, the shipping capability, specialized training, local hire and controlled industrial development. We've talked about ownership. We've talked about benefits to the State of Alaska. We'd like next to talk about the viability of this project.

There we will talk about management, descriptions and scope, marketing and financing. The organization and management doing what we call the development phase, which is where we are right now, is we have a Board of Directors, as shown -- one of the persons on the Board who is here today but will not speak is Terry McCall; many of you know. The Chief Executive Officer we'll hear from later is Gordon Cain and then we have people and companies involved in the technical aspects, the marketing aspects, the legal aspects, shipping, engineering design and construction, finance, legislative affairs, planning, training for local hire and all of these functions have been active since we started working on the ALPETCO project. One of those that has been very helpful to us in both marketing and in technical considerations is Chem Systems, Inc. and we've had two persons work with us there, the President of the Company, Peter Spitz and the Vice-President of the company, Chuck Campbell. Some of you may recall, Chuck Campbell spoke at the Petrochemical seminar in Anchorage late last year. Chem Systems is one of the leading international firms specializing in marketing and technical support of what we are proposing to build. They have offices around the world. They have a staff of 80 full-time professionals. Their clients include most of the world's leading oil and chemical companies. They're experienced in all phases of petrochemical development worldwide, including the United States, western Europe, Japan, and the Middle East. And they're experts on supply and demand and economics in the field of petrochemicals.

The other, most important ingredient to our management, is the person who's going to be the chief executive officer of our efforts. This person is Mr. Gordon Cain. He has over 30 years experience in the petrochemical industry. As a successful, seasoned chief executive officer, he's been responsible for promotion, putting these together, forming the company, staffing and managing petrochemical facilities in the United States. He's had experience with the Japanese. He's put together a petrochemical joint venture company in South America and he's had experience with petrochemicals in Europe. He is currently President and one of the organizers of Petrotex (ph) Chemical Corporation in Houston. Prior to that he was -- he headed up the petrochemical and chemical activities of Continental Oil. He's also currently Chairman and an organizer of Petrocrema (ph) Argentina S.A. in Buenas Aires. I'd like to introduce Mr. Cain to talk to you about what this facility will do and will look like. Gordon.

MR. GORDON CAIN:

Well Gentlemen, here is a rather simple diagram of the units that we will have in the ALPETCO project. The core of this operation will be an oil refinery which is shown on the left side of the screen. And this refinery will be, for all practical purposes, the same as any of the other refineries that have been proposed to be built here. The one difference in it is that we will take the part of the gasoline fraction that is not necessary for the Alaskan market and some part of the heavy fuel and convert that into a petrochemical feed stock.

Now from this point on precisely what we do is not clear because this will be determined by the market and by the nature of the partners that we get. But in general terms this will include an Aromatics plant which will make such compounds as benzine, taulowene (ph), zyolene (ph) and an Olefins (ph) plant that will make compounds like ethylene, propylene, and butadiene. And then there will be downstream plants from both the ethylene plant and the Aromatics plant which would make such things as polyethylene, polypropylene, ethylene lycol which is antifreeze, ethyl alcohol, which is a gin or any other such place; polystyrene, polystyrene fenol -- those are all the number of possibilities that might go into boxes that are labeled one, two, three, four, five over there. Now this will be a large complex and will have a very substantial utility requirement, both for electricity and for steam. And so it will be necessary for us to build a large steam, electric plant and very likely the balance of this is such that we will need more steam than we will electricity so it will have some excess capacity to generate electricity. So it is possible that this plant will have the capacity to sell electricity to any of the nearby utilities or even preferably to have one of the utilities build and operate that part of the plant for us. In addition, if there is coal available at the time we go on stream, this could very easily be a coal fired plant. We think by that time the liquid fuels that we will make will be more expensive than coal and it would probably be more economical for us to operate this with coal firing if the coal is available.

Now going back to the refinery for the minute -- as I said, this refinery is essentially the same as the refinery that has been proposed to be put here by some of the other people and the economics of this refinery part of it, the market that it will serve and so forth, are probably the same as the things that have been proposed before. And in examining the viability of the refinery, we think of course this is a viable project -- and we have support for this in that there were at least two or three other proposers that also wanted to build refineries. Now this was, in spite of the fact that everyone recognizes the cost of construction and operation in Alaska, is greater than the cost of construction and operation elsewhere -- but in spite of the fact, we and other people think that we can overcome this Alaska disadvantage in the refinery. Then if you look downstream from that, the Alaska disadvantage, to the extent there is one, gets to be much less in the downstream projects than it was in the upstream project, in the refinery. And by downstream I mean the Aromatics plant, the Olefins plant and all of the plants that use the olefins. Now the reason for this is that in the refinery you upgrade the crude oil only a relatively small amount per barrel. And as a result, this Alaska disadvantage is a fairly significant proportion of the total cost. On the other hand when you go from these petrochemical feed stocks to things like polyethylene, you upgrade the oil a great deal and this same Alaska disadvantage

is proportionately much less than the downstream part of it than it is in the refinery, so that the addition of these petrochemical facilities to the refinery improve the overall economics of the project. And, of course, in improving overall economics, they increase the probability of success of this. Now this is a big, complicated project and in spite of all of the organizations and facilities that you have seen on the earlier charts, it's going to be a big thing to do and it would tax -- it would be frankly beyond our resources to do by ourselves. And so we fully intend to take into the different parts of this enterprise partners who can bring to it know how in the operations of these particular things, people who are knowledgeable of this and money and agreements to take products. And this is an essential part of our plan and we have many indications of strong interest on the part of these potential partners. And there's a good reason that we should get this sort of interest because the petrochemical business in the United States, and in fact all over the world, is sort of divided into two pieces. About half of it is run by oil companies who have sources of raw material and can break that into petrochemicals with all the advantages of having the raw materials supplied. The other half consist of chemical companies who buy their olefins and aromatics from oil companies and those companies are continually uncomfortable at being in the position of not having a resource of raw material for their operation so it is that kind of company who wants the benefit of the certainty of supply that it would have here in Alaska, that we will look to find partners to help us carry this operation out successfully.

Now the reason that these partners want to get into such enterprises as this is because they need the products that we will put out and Mr. Spitz, who Mr. Honig introduced earlier, will discuss with you the market for the petrochemical products of the kind that we propose to make. Peter.

MR. PETER SPITZ:

Thank you, Gordon. I would like to cover with you now the basis for this project in terms of markets, tentative products and product configurations, economics and feed stocks and also how this project will fit into the overall scheme of things in the world of petrochemical manufacture. This is a very major project, certainly for Alaska and for the U. S. as well, in the sense that it is a large petrochemical facility and one that is needed by the world market at least in terms of quantities for the world market, as you will see.

Now, in starting my presentation, I would like to have you think not so much about the year 1978, but rather the period of 1985 and onwards when many people think we will have quite a different situation in the world of energy, particularly petroleum, scene. The many studies that have been carried out in the world oil situation by such respected organizations as the Department of Energy, M.I.T., the CIA, a number of others, have predicted that regardless of exactly when this will happen, there will be a point in time and probably most likely in the late 80's,

when the OPEC countries will no longer either be able to or will wish to, supply the overall gap in demand for world petroleum. At this time right now, of course, there is a surplus of oil, you might even say a glut of oil and there does not seem to be an oil shortage, but as you extrapolate world energy demands and the the key role that oil fulfills in it, it is not too difficult to predict that by some time in the late 80's, certainly no later than the early 90's, this situation's going to change quite dramatically and by what very recent pronouncements by the Department of Energy and by a number of other groups, have said certainly confirm this.

On this basis the ability for any petrochemical manufacturer to have at his disposal the ability to buy a significant amount of crude oil for a long period of time through the 80's and 90's and beyond, will be extremely important and will be worth a great deal and that really is almost the key of the entire project and why we think this project will certainly be viable.

Now ALPETCO originally started looking at the possibility of either building a refinery or a petrochemical plant because it's not obvious that you should build a petrochemical plant. As you know, some of the other proposers chose to select a refinery as their objective. But in looking at the relative world demand growth for petrochemical versus fuel products, you'll come to the conclusion, as you'll see in this first slide, that petrochemicals grow and are expected to grow at a lot faster rate than fuel products. Now fuel products that are represented by the two lower curves seem to grow with such indicators as population and GNT and in fact, as the U.S. and other parts of the world cut down on their energy consumptions, they grow at a lower rate than these indicators. And furthermore, when you look at the fact or think about the fact that the world must try to get by with less oil as time goes by since it's a perishable limited commodity, it will actually grow at a lower rate because oil will be supplanted by coal and nuclear energy and by other alternative energy sources of a more far out nature in 20 or 30 years. So you see the predicted growth rates for petroleum products is really quite low and will get lower as time goes by and these are not just our figures, but they are recognized figures by people who publish such things including even the major oil companies. And, on the other hand, the petrochemical growth rates which have been high and which will be dropping as a result of the fact that things can't keep growing forever at 8 to 10% per year, are still very high and will in our judgment and that of others such as Stanford Research, Arthur D. Little, etcetera will keep growing at the rate of 5 to 6% over the next 10 to 15 years. So looking at these two things, and recognizing that there is not going to be a need for too many more refineries in the United States, in fact Shell had said at one time that the last U. S. refinery will be built in the 1980's, was quite an interesting statement, about a year and a half ago, anyway lead ALPETCO to conclude that building

a petrochemical facility makes a lot more sense. There will be a need, moreover, for petrochemical feed stocks to be made in refineries so that the refinery that ALPETCO plans to design will fit into the overall scheme of things and in that connection we should note that in all parts of the world, other than the U.S., the major olefins like ethylene and propylene have always been made from petroleum feed stocks such as naptha and gas oil and in the U.S. where gas liquids were used over the first 20 or so years of the petrochemical industry, even there in the last several years, approximately 80 or 90 percent of the new ethylene plants have used petroleum rather than gas liquid feed stocks so that is again the point that was very important in ALPETCO's consideration in planning this facility.

Now I would like to cover some of the markets we are thinking about for the petrochemical products for ALPETCO and in the next slide we see that the U.S. West Coast has a fairly large market for petrochemicals because it consists of 28 million people and as I will note again later, it actually has a very, very limited number of petrochemical facilities and actually no world size ethylene plant. This is almost an anachronism. Other companies have thought of building a plant there but have been unable to do so and we therefore look at the West Coast market as a very logical and very important market for the ALPETCO project since this market is currently supplied through rather long and expensive transportation lines from the U. S. Gulf Coast. The other important market we're thinking about and that's very important to the ALPETCO project is the remainder of the Pacific Basin, which is kind of hard to show on one slide but it includes Japan, Taiwan, the Phillipines, Hong Kong, which has a very high import rate of plastic, plastic resins because it exports a lot of plastic fabricated products, Thailand and Malasia, Indonesia and the Phillipines, and not shown, the West Coast of Latin America and some other countries. And this market is growing rapidly because the population is large. Our company has made a lot of projections and has shown that this market will be able to buy a lot of petrochemicals, and will eventually build their own plants, but not for some time -- in many cases, except for Japan, of course, and will be a very important market for a project in Alaska. Now this market has been supplied, to a large extent, from Japan, but in the last year or two Japan has been losing this export market partly to the U.S., because the facilities in Japan are becoming somewhat antiquated and in many cases because feed stocks in Japan are high and because Japan has other problems that will be discussed by the next speaker. So we're talking about supplying the U. S. West Coast and the Pacific Basin, which are currently being supplied from two areas, mainly the Gulf Coast and Japan, which are in a sort of transitional situation. But now what is happening on the Gulf Coast? The situation in the Gulf Coast is that in the past petrochemical plants were built there because of inexpensive gas liquids and because of a highly abundant petroleum and natural gas feed stocks there. As you, I'm sure, know these gas and petroleum products are now in decline there. Every year production rates go down, particularly for petroleum products and will keep decreasing

and so the logic of building plants on the Gulf Coast is no longer there except for the existing infrastructure which will obviously continue to be an attraction to some companies who want to locate there. But the feed stock advantage will no longer be there, particularly as crude oil reaches world market levels. Everybody will be using feed stocks of roughly the same price as time goes by. In Japan where, I said before, there are problems with high feed stock prices and plant siting, there will also be difficulties so what we're really seeing now is a kind of a structural reorientation of the industry where petrochemical facilities are not as likely to be built either on the Gulf Coast or in general near existing downstream facilities but rather in areas where crude oil or natural gas or gas liquids are being produced. This immediately brings in mindthe OPEC countries which, as you know, have great ambitions to build petrochemical plants and are in fact building some plants. The problem with the OPEC countries though is that number 1, the construction costs there are even considerably higher than in Alaska on the basis of having absolutely no infrastructure in the sands of the Middle East. We have construction factors relative to the Gulf Coast in the area of 1.6 to well over 2 times that of the Gulf Coast construction cost versus a 1.3 to 1.4 factor frequently used for Alaska. Nevertheless, the OPEC countries will build some plants and will be entering the world market. But to put this in perspective, however, even if two or three projects are built in Saudi Arabia in the next 10 to 15 years, and let's say 2 or 3 or 4 more plants in other parts of the Middle East, this will as you will shortly see, reprepresent only a very small percentage of the world market and certainly not the kinds of production quantities that will dramatically alter the world situation and something to be terribly concerned about.

And so, and then there are other problems, of course, is that the OPEC countries are somewhat unstable in the eyes of a lot of companies that would like to produce there and the fact that these companies are over in the OPEC countries like Saudi Arabia and Iran and Abu Dhabi and so forth, means they are looking for alternatives to what they would like to continue to do on the Gulf Coast and cannot do and that is I believe also why we were able to attract quite a bit of attention to a project in Alaska.

Now we will start looking at the specific markets and market projections that we are contemplating for this project and we're basing some of our thinking on. The next slide is I think interesting because it shows you the power of geometric growth as it were. The 1980 figures for ethylene, propylene and benzine, the three most important petrochemicals, are I think accepted by everybody who knows the business as being quite representative of what will be the situation at that time. Assuming a growth rate as I've indicated before in the area of 5 to 6 percent per year and multiplying this to the 10th and then to the 20th power, which is what you're doing, you arrive at very large amounts of ethylene, propylene and benzine. Now we may be wrong about these projections, though

we are not out of line with other people who make these. Maybe the growth rate in the 90's will only be three or three and a half percent. But even if we talk about ethylene being only 70 billion pounds, you can still see the huge amounts of additional capacity required just for the United States alone. And when we contrast that with the ALPETCO case I've shown and as you see we show it as a case -- there are other cases that make less and more ethylene and propylene. You can see what a relatively small percentage of U. S. production this actually amounts to and this will be shown again in another slide.

The next slide is taken from a presentation that Union Carbide made to the security analysts a number of months ago -- it's still quite up-to-date. Again it shows the supply of ethylene on the upper part and the reason it (indisc.) each project or projects each year at a certain amount of capacity, the lower (indisc.), the smooth line represents the effective capacity because these plants will operate somewhat lower than the rate of capacity and the lowest curve shows the demand projections -- the reasons the curves digress a little bit is because this really should be shown on a log lock scale to be most properly shown. But in any case, the point is that every three or four years supply catches up with demand -- I'm sorry, demand catches up with supply, unless more plants are required.

The next slide please.

I indicated before we were looking at the U. S. West Coast and here Chem Systems has made a number of studies and facts. I gave a speech at the National Petroleum Refineries Association Petrochemical Meeting last March from which this is one of the presentations or exhibits and this shows that the West Coast market is large and getting larger. None of the materials I show here are actually made on the West Coast today with I believe one exception, polyethylene, which is made in very small quantities, almost negligible.

The next slide please.

It shows the same situation in numbers roughly, again showing this high growth for petrochemical derivitives, ethylene, (indisc.), polyethylene and styrene on the West Coast. You see, for example, polyethylene demand now is in the area of 700 million pounds, slated to grow to 1.9 billion pounds. These demands must come from somewhere and we believe that Alaska, an Alaskan plant, could supply a certain percentage of these and we would only need to sell -- need to fulfill approximately 20 or 30 percent or less of West Coast requirements in order for our project to be viable. The number of companies who market on the West Coast would be interested in obtaining products from other sources so our thinking there is not to

become a new marketer of material but work with existing marketers of these materials on the West Coast and we have already talked to them and as Gordon has said before they have expressed considerable interest in working together with us in the form of joint ventures or other business arrangements.

Moving out to the Pacific basin countries, this next slide is our estimate of net import requirements for a number of these countries and that other slide that I showed you, showed for example that carrying all the plants that have been built and looking at the man increases, the region has a need for net import of a fairly substantial amount of these technical petrochemical and this again therefore the market that we want to go after.

The next slide summarizes the ethylene requirements for both of these markets and shows that this for the U.S. West Coast and for other Pacific basin areas totals of ten World Scale ethylene plants are required through 1990 and we are thinking in terms of one plant at least for the time being so that we are looking at selling--we are looking at ALPECTO fulfilling only 10% of this new market (indisc)--expanded marketed requirement through 1990. And in the last slide we show therefore a number of possible chemicals that could be made in Alaska for fulfilling either or both the U.S. West Coast market or the Pacific Basin market and I think this will explain to you why we have not yet chosen the final configuration for the plant. We must decide which of these chemicals to make and we can't make them all because we want to build world skilled facilities which means probably only 3 or 4 of these types of products should be made and they should be made in fairly large quantities. Now leaving the market and addressing ourselves next to the question of economics and Alaskan economics, which has been certainly criticized in some of the articles I have read in newspapers and some of the statements that have been made. Such statements as ridiculous to build plants in Alaska because of markets elsewhere, etc. also that petrochemical should not be shipped all around the world, they should be made where they are consumed. Well, there are some falacies in this, although I must admit, it does represent some national wisdom of the--perhaps the 50 and the 60's and early 70's. We had an event that occurred in 73 that has changed a lot of things and you know what it was. The ALPETCO Companies are starting to become interested in building petrochemical plants and so a lot of petrochemicals are going to be shipped all over the world. Furthermore, the world trade in petrochemicals was always very large and in fact, contributes very very substantially to the positive aspect of our balance in trade. Were it not for our exports of petrochemicals our balance of trade would be substantially worse. This also, I think, is important to know in connection with some comments that were made that for every barrel of oil that we can turn to petrochemical and export to Japan we have to import another barrel of oil from the Middle East. That's true. However, the value to the U.S.of petrochemical export is roughly five times the value of the oil

that's imported and so we gain, we have a 5 to 1 leverage in terms of the U.S. balance of trade for converting oil into petrochemicals.

The next point is just how unfavorable are the economics in building a petrochemical plant in Alaska and we fully recognize that there is a disadvantage due to the higher construction costs in Alaska. What we feel are mitigating factors, the factors that will turn the situation around are as follows:

1. We know that the Japanese petrochemical production is expensive because they must import their feed stocks from the Middle East and have very high transportation cost. We feel that an Alaska plant can be competitive in shipping petrochemicals to Japan.

Secondly, as I indicated to you, the logistics in cost of shipping petrochemicals from the Gulf Coast to the West Coast which goes either through the Panama Canal or by hopper car, by rail from the Gulf Coast of California are high and figures indicate that it would certainly be reasonably economic relative to those transportation economics.

Next point is, as I said before, the economics of building petrochemical plants in OPEC countries is high yet they are proceeding. So what really is happening is the world is changing and that petrochemical plants will be built more and more in areas where the feed stocks are because these areas, likely not, in most cases, ship all of their feed stock to world markets that would like to use these feed stocks to aid in their own industrialization program and I think you might say, being accused of being in favor of a project that might have questionable economics could be turned around and could be restated as saying we think that it would be important to find out if it would not be possible to build a viable economic petrochemical facility in Alaska. Because we have a feeling that it can be done and I would like to try it and ALPETCO is taking all the risks in order to be able to do this. And we further believe, as Gordon as indicated, the feed stock security that ALPETCO and it's proposed partners will receive will in our judgment offset the economic penalty that will undoubtedly occur to a subminor extent due to an Alaskan petrochemical facility. Finally, to answer a comment along the lines that well, this facility will be built and then it won't be viable and then you know the State will be stuck with a facility that will not be economic. It is our judgment, working with banks and with financial institutions and lenders, there is no way and I think the bankers will address themselves to this at a later point, there is no way that they are going to agree to lend this kind of money we are talking about here unless they completely satisfy themselves that this facility will be economically viable. The banks do not want to get stuck anymore than manufacturing people do.

A final point I would like to talk about briefly, which I alluded to before, relates to gas liquids versus petroleum feed stocks.

This has been discussed at some lengths in the Press and elsewhere and is certainly of interest to Alaska because of the North Slope gas and the extraction of gas liquids that has been proposed.

We don't know all the answers on this by a long shot and I think the reports that have been prepared by various consultants including Gardner and Moore, Salidus (ph) Battelle and others don't all agree with each other either which just shows that the problem is complicated. There are a lot of variables that relate to what the final well head price of gas is going to be, what's going to be the price of gas in the United States, the diamond or the lime, the amount of gas liquids that can be left in the gas, the amount of gas, ethylene, that can be extracted and so forth. Again we don't know the answers and we think there is a lot of uncertainty about this and it's impossible to make any firm plans on this. But we can say some things about it that I think go beyond the specific timing and economics.

One, ALPETCO is interested in cracking gas liquid if they were available to ALPETCO and if so, this will be possible because the cracking furnaces that ALPETCO plans to build will at least in part be designed to crack gas liquid if and when they are available to ALPETCO.

Secondly, the amount of gas liquid that are going to be available no matter whose numbers you look at are going to be very ample. There could be enough there to build a project along the gas pipeline if that turns out to be reasonable and economic as well as cracking gas liquids in the coastal region where ALPETCO plans to build a plant. The projects are not at all competitive because neither one of them serves the Alaskan market anyway. The markets that are being served from Alaska are the world markets I tried to depict in my slides and since there is plenty of feed stock in Alaska if one project makes sense, probably two projects would make sense. Not a market question, strictly an economic question. So we don't think these projects, if the gas liquid project were to come about, we do not think it would become competitive if it's decided to extract liquid and to build an ethylene plant for example ALPETCO could even take the ethylene by pipeline from that location and back out again feed stocks from its own crackers. This project could work with such another project on gas liquids with no trouble at all and this is what our planning is based on but the difference is the ALPETCO project can proceed right now, its based on petroleum feed stocks. Petroleum feed stocks are being used, as I said, in 90% of the world's petro chemical facilities and we think, that certainly there is nothing wrong with that and in fact, there is some positive features because from petroleum feed stocks you make not only ethylene but you make a lot of propylene, benzene, butadine (ph) and we are looking at a whole spectrum of products where cracking gas liquids really make primarily ethylene and a small amount of propylene.

Finally, on marketing strategies, this has been covered to a considerable extent by Gordon. I've talked about the West Coast and Japan but we do have some other thoughts to communicate to you on Japan and here I would like to introduce Mr. Tydings who has a special background in Japan as a special consulate to the Japanese Embassy and in Washington with a great deal of background in U.S Japanese trade relations and a member of the United Nations Consul for Population Activities. I would like to introduce at this time Mr. Tydings.

Excuse me, one minute. Would the continuity of your presentation be affected greatly if we hold him for about 10 minutes?

Not at all. We will break for ten minutes.

(OFF RECORD) (ON RECORD)

Hear his testimony and answer questions until tomorrow. So what the schedule will now read tomorrow at 1:30 Commissioner LeResche and Bonard Lord (ph) 3:30.

Unidentified speakers: Will that conflict with 8:30? Sure will. Will that conflict with what? Would that be more convenient for you to go at 3:30 Commissioner? If you have to be at another hearing. I would like to make the other one also. Okay, fine we'll put you on at 3:30. Will Mr. Moore testify at 1:30? Yes, I hope we can arrange that. Yes, Senator Tydings is going to speak; Joe, you want to come over here, please, speak to the Japanese and the U.S. Federal Government aspects.

JOSEPH D. TYDINGS:

Senator Colletta, Representative Miles and members of the Special Committee. I appear here as a special consul ALPETCO. I also appear as one who has some experience in the legislative branch of the State Government and the executive and legislative branch of our own government. I'm also legal consul in Washington for the Japanese government on matters relating to trade with the United States and consul in Washington for the Kaydonrins (ph) which is the Japanese consul of Industrial Organizations on energy matters, Japanese Federation of Power Companies, Japanese Atomic Industrial Federation, and the Japanese Committee on Energy Policy Promotion, which was organized and headed by Ambassador Sheba (ph) until he was just made Czar over all trade negotiations, industrial matters and related Governmental Reorganization. I'm also representing and consuling ALPETCO with respect to this joint venture with the personal approval and encouragement of the Prime Minister of Japan and the approval of the Chairman of the Energy Policy Committee of the Kaydonrins (ph)

Now there are significant strategic aspects to the marketing of this particular plant and this particular project as they relate to the Japanese people and the Japanese nation. Let me just

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refresh your recollection just a little with a more recent history of Japan particularly since World War II. (Cough, indisc) a remarkable degree of energy and know how, Japanese people have been able to rebuild their country after World War II into one of the principal and industrial leaders of the free world. But today they are essentially a nation which imports raw material, adds value to them, and exports them. And the most vital raw material in the Japanese list of imports are the energy raw materials. Japan is forced to import over 90% of its fuel oil and its energy of fuels, other than a little bit of coal they have there. Thirty seven years ago an embargo on oil to Japan by major countries in the world was sufficient to send them to war. That's perhaps, in today's concept, an over dramatization. But the strategic importance of fuel oil feed stocks of petrochemical facilities cannot be over emphasized as it relates to the Japanese people particularly in the 1980's.

The Administer of International Trade and Industry meeting recently issued some statistics which will relate to the Japanese need for increased fuel oil by 1982. And their shortfall in 1982 will be a million and a half barrels of oil a day. Sometime between now and 1982 they've got to find that source of additional fuel.

I think perhaps a word about the relationship in Japanese context between the Government, Kaydonrin (ph) or the Industrial leadership of the country is in order. Since World War II the political leadership of Japan has been divided by a Party call the Liberal Democratic Party. This Party, I would say is a sort of a broad-based philasophical conservative coalition. It is very closely related to the Kaydonrin (ph) or the Japanese Consul of Industry. It is inconceivable that any final decision with respect to the opportunity to participate in so important a project relating feed stocks as this would be made without joint participation by both the government and Kaydonrin (ph).

There is another aspect to the Japanese strategic position in the world today which indirectly relates to this and that is the unique relationship between Japan and the United States. As you know, under the treaties negotiated under General MacArthur at the conclusion of World War II, Japan has not rearmed. Japan's principal trading partner is the United States. The Japanese government and the Japanese people value their relationships with the United States very highly. They are very cognizant of the tremendous strains which have been placed on that relationship by the current trade in balances and particularly by the Japanese exports to the U.S. a number of important commodities which have very strong political constituency. The Japanese government is very aware of the steel caucus in our House of Representatives and in the Senate. They are aware of the constituency which relate to television products, shows to a great variety of U.S. goods which have been competing and not too successfully with Japanese goods in recent years. They are greatly concerned with the possible retaliation from the United States with respect to trade barriers, which could be economically very, very disastrous

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to the Japanese government and thus they have been seeking ways to increase their imports to the United States. There is a major trade delegation in Washington this weekend, sent here purely to try and foster imports from the United States to Japan. If you have followed the journeys and travels of our special trade representative and his deputy in the last weeks of December, you will recall that there was two major meetings in Japan, at which time the Prime Minister stated publicly that his government would make every effort to increase the imports from the United States and, as a matter of fact, he had a shake-up in his entire cabinet. So you have that fact of life of the Japanese government today quite aside from the strategic need of feed stocks or other sources of fuel supply, the trade-in balance and the strain put on you as a Japanese relationship.

Let me, if I might, shift to our own government and our own strategic posture in the United States.

We have seen in the last two years two things, we've seen a basic trade deficit in United States relationship with the rest of the world caused primarily by the need to import oil from the OPEC countries. But in those trade-in balances the great in-balance with the trading nations is between the United States and Japan. Up until a few years ago we were basically equal trading nations. And that Japanese in-balance has caused, as I indicated earlier, protectionist movement in our Congress which we have not seen since the 1930's. The Smooth Holly Tariff (ph) was originally a bill introduced by a Senator Smooth (ph) Representative Holly involving just one commodity in 1930 and before it was through the Congress there were 140 different tariff barriers on it and that led to the whole world breakdown in the 1930's of trade. Now, the position of our government has been since President Eisenhower right through every President, right to the present administration, to try and maintain the United States' role, preeminent role as the greatest trading nation of the world, and we still are the greatest trading nation in the world, and try and keep trade barriers at a minimun. But I can tell you and I think that any responsible reporter from Washington will tell you that pressures on free trade are greater today in Washington then at any time in 30 years. So that United States government has a very serious problem if it's going to maintain our posture as the greatest trading nation and that problem is made greater by the Japanese difference in the balances of trade. So it is this particular project, at this particular time, that is a project in Alaska which would market high value added products, such as chemical products to Japan, with significant dollar amounts, whether we are talking about 40% of the output or 50% of the output or 60% of the output of this plant, this would be a major contribution to the United States trade balances. This particular project at this time falls right in line with what our government is trying to do. We have basic ALPETCO proposal has been presented and briefed to the top career civil servants and our special

trade representative's office, Commerce Departments, State Departments, Treasury, Interior and the National Security Council. We had to do this at a time when we are not the awardee of the contract, when we would have been basically one of the competitors merely to present proposals as basically presented to you and to the Royalty Board. Without exception reaction to our proposal is that it is on all corners, all four corners, consistent with the international trade policy of our government that when the State of Alaska concludes their deliberation, the decision making process and awards the contract, that the top career and the top decision makers in our government will consider what steps, if any, will be appropriate to take in support of this proposal in light of the vital U. S. national interest. They made no representations that it would be put on the formal agenda between the U.S. and the Japanese trade negotiations, but in my judgment, it is difficult to see given the consequences that it would not be given very serious consideration. In my own judgment, I think it would be on there.

To sum up what I have basically stated, the ALPETCO proposal as it relates to Japan, as it relates to marketing in Japan, is an ideal vehicle for Japan to increase its purchases from the United States which Prime Minister Bacooda (ph) has said they are trying to do and which I genuinely believe they are. It will help provide an additional source of feed stock, a steady safe supply pending on the type of negotiations, the type of joint venture which they may enter into which (indisc.) and negotiates with one or more Japanese groups. And (indisc.) the bottom line of the Japanese it could be a very highly profitable joint venture. From our point of view, the United States' point of view, this proposal is in line with the efforts of the special trade representative is making with the admissions of Dick Rivers and Ambassador Strous made in December which was basically to tell the Japanese government they had to increase their purchase from the United States, they had significant effort to reduce the inbalances and bring the trade balances in line, so that we have a proposal which is right in line with our own policy and which would offer, I think significant advantages to the Japanese people and to the Japanese government. I think it's important to know that the timing of the proposal as it comes in 1978 such as to make just about inevitable, a strong Japanese participation as a possible partner for at least some of the production of this complex. Thank you.

CHARLES O. HONIG:

We've talked about the management and the description and scope of marketing and the last point on viability of the project involves financing. From the beginning we have had as our investment bankers, Lehman Brothers, Kuhn Loeb and E.F. Hutton as our co-investment bankers. And as our commercial banker, we have had Chemical Bank and all three of these institutions have met with us and counseled with us and worked with ALPETCO beginning last July and they have attended royalty board meetings with us in Valdez, Anchorage and Juneau and they have met with us in

New York and Houston and they've been posted almost daily on the progress of this project. So they are an integral part of it and we would like for them to address briefly what's involved in the financing and I'll ask first Tom Kenny, who is managing director of Lehman Bros Kuhn Loeb, if he will talk some about the permanent financing aspect. Tom --

TOM KENNY:

Thank you. Good afternoon, Ladies and Gentlemen. Charles introduced me as the managing director of Lehman Bros. Kuhn Loeb, Inc. This is a brand new firm on Wall Street. It was organized in December 1967 (1977) so it's about three months old. However, we have two predecessor organizations that have been around for considerably greater time than that. Lehman Bros. was formed in 1850, Kuhn Loeb Co. was formed in 1867. Both organizations were important investment banking firms during that more than 100 year period of prior to our merger in December of last year. Both investment banking firms were in a forefront of American finance raising capital during that period. More important American business enterprises in significant industry. And as Charles says we have been associated with this important project since its inception, and our thinking concerning the structuring and implementation of the permanent financing has not changed even though we've perhaps elaborated a bit on it during that period of time since we started speaking of it and what we are talking about is structuring a permanent financing as a project financing. I'm talking about the permanent financing for the project as compared to what the construction financing which is what my friends in the Chemical Bank will address in a few moments.

Now, we have told ALPETCO, and continue to tell ALPETCO, that given the approach that they are using that we do believe this project can be successfully financed on a permanent basis, using traditional sources of capital at competitive capital costs. What I mean is, of course, the interest rates and the other capital costs would be similar to those incurred by other high fray developments of this nature or any other nature in natural resources. As a project financing we would expect a considerable amount of support where the financial structure would come from long term supply contracts running to (indisc. cough) utilizing and using the output of this facility. This will permit us to use a capital structure that probably would be somewhat more heavily step oriented than equity oriented but we anticipated that but certainly there will be plenty of the latter also. In connection with that we would anticipate that there would be participations in the equity of this project or its component parts which you've heard some things about it today by the people who are using the product and entering into the long time supply contracts. Such participation and arrangements would not be unusual but to the contrary something I would expect to take place as Mr. Cain

develops these arrangements with what he has characterized as his partners in the thing. We have written letters in support of the applications that ALPETCO has been making into the various authorities up here. We stand by those letters, we continue to feel that the structuring as a project financing with long term supply contracts that we can raise the necessary money in the convential markets. These markets will involve (indisc.) issues of both taxable bonds and untaxable bonds. The total amount of the financing we anticipate may, aggregate as you've heard here about 2-1/2 billion dollars, however, we are talking about a project that is going to be accomplished over a several year period. It's also going to be accomplished in several discrete stages. The capital markets as we understand them at the present time and we think we do understand them, and particularly the U.S. long term capital market. That is going to be the major source of this money we think will, in fact, absorb financing of that magnitude without any difficulty.

CHARLES HONIG: Thank you, Tom. I also would like to call upon another investment banker who is Executive Vice President of E.F. Hutton, who also by the way served under both Johnson and Nixon as the public member of the National Water Pollution Control Commission, Jim Lopp.

JIM LOPP:

Thank you, Charles. You know our public relations firm put out a slogan that when E.F. Hutton talks people listen. Which people as you travel around the country you make great mention of that after reviewing the contract the State put together, I believe that when Alaska talks, ALPETCO listens. I--reviewing it suggested that if anything more was traded, I think we wanted to be in the spot of raising the financing of the State. You have a very financable contract at this point of time.

Because of the magnitude of the project, I thought maybe we might just mention a few of the assets of the E. F. Hutton Co. in terms of what we hope to be able to bring to the table to help to raise the capital that is going to be required.

E. F. Hutton Co. is about 75 years old and has a 190 offices in the United States, 12 in Europe, has about 2700 salesmen with representation of about 500,000 or half a million, retail and institutional accounts. So we believe that we will be able to bring a lot of these resources to bear in the placement of the securities.

Last year E. F. Hutton Co. managed to co-manage in the placement of debt securities and equity securities 4.2 billion dollars. As my co-investment banker pointed out, we have been involved in this project since its inception and we have continuously supported the ability of this project to be financed given its economic viability. I think it's important for members of the Senate and House to understand that projects like this have been financed in

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the past on a project financing basis and maybe a few examples would be helpful.

Down Australia way, we've had very huge iron ore projects such as Savage River, Rogue River and Hammersly (ph) which has been financed on a project basis such as we are talking about here. In British Columbia you may be familar with the Four D (ph) coal project as well as the Lorne X Copper project which has been financed on a project basis. I think maybe one of the best analagous situations to what we are talking about here, is in Indonesia, 21 utilities from Japan, financed a billion and a half dollar L & G facility to supply them with gas for 20 years. This was 100% debt finance and Alaska Interstate who was involved in structuring this transaction, retained the 22% interest in that project. That basically is the type of thing that we are talking about here.

Now, interesting enough let's talk just a quick moment about where these funds are going to come from. The commercial banks are going to talk about their construction funds and revolving credit agreements. We also look for credit to come from suppliers, export financing, medium and long term debts, both taxable and tax exempt and we also believe, and we said this to ALPETCO, that we will be able to raise required equity to support the financial structure of this balance sheet that they have projected. The taxable debt will be provided mainly by, on a private placement basis, with life insurance companies, pension, profit and retirement funds. The tax exempt portion of the debt and we believe in some of the members of our organization under the banner of another firm, were involved in coming up with the idea of financing the facilities at Valdez on tax exempt basis and spent quite a bit of time on that. and we've taken the analagous facilities, docks, wharfs, and some of the infrastructure and believe that under Chapter 61, Title 44 of the Alaska law, we can finance maybe up to 350 million of this financing with tax exempt bonds. Now this is important to the economic viability or helps support it in that the debt rate on tax exempt bonds is some 2% below that of taxable credit. I think Charles, this would rap up my summary of it.

CHARLES HONIG:

Thank you, Jim. We'd like next to hear from our Commercial Banker and speaking for Chemical Bank is Senior Vice President, Grenville Paynter, who also likes to fish in Alaska.

GRENVILLE H. PAYNTER:

Thank you, Charles. I guess it is appropriate to mention a little bit of Chemical Banks pedigree.

We were started in 1824. We ended up last year with total assests somewhere in excess of 31 billion dollars, we were in excess of 100 million last year, we have capital funds in excess of a billion 6.

The short term or the intermediate term facilities that we are concerned with in the banking side are neither exotic nor esoteric

but are very typical of the kinds of projects that we are looking at these days. They are ones that also many of our cohorts in the banking fields are familar with and we have discussed them not only with existing banks that work with Alaska Interstate but also with banks in Alaska and in other money centers and without exception, we've gotten great expressions of strong interest in these kinds of credits. There are three basic ones we are talking about. The first is at the request of Alaska Interstate, we've examined their situation to determine how best and to raise the amount of equity that they would put into ALPETCO in the beginning. We have determined that a hundred million dollars would be easily raised and we have also told them that we would make 20 million dollars of that available upon ratification of the contract to help them with or supply the money for the start-up cost.

We have further told them that we will take 50 million of that total credit ourself. We have indicated to ALPETCO that we believe that a bank group for the interim construction financing of the refinery could be set up. That under present plans a 400 million dollar commercial bank credit should be satisfactory. This credit would be set up against a take-out commitment from long term lenders. Of this 400 million dollars Chemical Bank would be willing to take up to 100 million dollars and would act as agent for the group of banks that would provide the remaining funds. Other forms of financing such as already has been mentioned, supplier credit would substantially fund the remaining short term needs.

Finally, we have talked with ALPETCO about the working capital requirements, the marketing, the royalty crude oil. This encompasses the phase during construction of the refinery after the company has met the bench marks Charles has referred to in his presentation. Our analysis leaves us to believe that a working capital line in the amount of a hundred million dollars would be adequate and here again, Chemical Bank would be willing to take up to fifty million of this financing. Needless to say, each of these various credits is subject to a satisfactory credit agreement. But in each case they are typical of agreements that we work with every day. I'd like to conclude my remarks by maybe restating my opening comment that the Commercial Bank role in this project is personally conceptionalized is a role that No. 1 we are familiar with and No. 2 we believe can be successfully duplicated on behalf of Alaska Petrochemical Co.

CHARLES HONIG:

Thank you, Gren. The closing comment on the matter of financing relates to joint ventures and I'll just briefly refer to a chart that shows some of the possibilities. This is different from Gordon Cain's chart on the refinery but in petrochemical complex but it shows various ways that ALPETCO can work with others in

putting together in Alaska this type of facility. For instance, we refer to the center part as the core of refinery and that would be primarily in that respect just sulfur recovery, sulfur removal and the ports and docks might be owned municipally or owned separately from ALPETCO, the utilities likewise. As Gordon said we might bring in a big brother partner, a chemical company who might agree to build a olefins plant or one who might be interested in the aromatic aspects. .. So there are all kinds of possibilities for joint ventures which will result in our associating companies as Gordon mentioned with know-how and money and experience in this particular area.

I'd like to ask Gordon Cain if he might summarize what we have presented today.

GORDON A. CAIN:

Senator Colletta, Gentlemen of the Special Committee, word summary suggests that we are reaching the end of this presentation which may be of some relief to you. So I won't take too long to do this.

You have decided that you want to process your oil in Alaska if you can do this without any penalty to the State. Commissioner LeResche and the Royalty Board have examined the proposals that you have been presented with and they have reached the conclusion that the proposal that includes a refinery and a petrochemical operation (cough-indisc) presented by ALPETCO is the best of the proposals that you have received. Some of the factors that might have gone in their consideration are that this will create three or four times as many jobs and three and four times as much tax money in Alaska as any of the alternative proposals. Also, as I mentioned earlier,the addition of these petrochemical facilities to the refinery improve the possibility of the overall project and increase the probability of success. Mr. Spitz alluded to the fact that this project is not competitive with and probably will help your ability to use your gas liquids later. We would be a potential customer for these gas liquids, we don't want so much of them that it would impose on--impinge on your other project if you decide to go ahead with it. We will both, the gas liquid project and our project, will be competing in a world market in which there are ten or fifteen other plants of the same size that we are and the fact that one of those plants is in Alaska and one of those plants is our plant, will have little significance. Whether this gas liquids plant that is competing with us is in Alaska or Indonesia is not going to make that much difference in the overall competition because both of us are only trying to get somewhat less than 5% of the market that we are dealing with.

Now, you have been told that our project is the best project but you still have a reasonable question is the best good enough.

Now is this best project one that is likely to go ahead and have a chance for success. Now, if we were talking about a project that is going on stream today or if we thought the future was going to be a continuation of the present, if we thought that there would always be a surplus of crude oil, if we thought that there would always be an over-supply of petrochemicals, we would not be here talking to you at all. It would not make any sense to build this project or to put this much money in this. But none of us and none of the experts in this matter, think that things are going to continue as they are now. Prevailing wisdom is that by the mid 80's there will be a shortage of crude in the world. As you can see, the growth of petrochemicals, even if you used the lowest probable growth, will require that there be on a world wide basis a plant like the one we are talking about, built every six months somewhere in the world just to keep up with the lowest anticipated growth rate. So that although a billion and a half, two billion and a half, three billion and a half dollars is a lot of money in the context of this world petrochemical situation, this is a relatively small part of the whole thing. And the question really is what are the things we have that would make this a viable project, make it possible for us to compete in the world market?

Now this plant will come on stream in the late 83's - early 84. By that time we think that there will either be a shortage of crude oil in the world or it will be obvious that there is going to be a shortage. And since people operate on the basis of what they expect to happen, if people think there is a potential shortage of crude at that time, a source of petrochemical that is located in a political stable region, political special to this context doesn't necessarily mean that everybody gets reelected. It just means that nobody siezes the plant. In a politically stable region that the market price will be a very attractive source of chemicals for users of petrochemicals.

Now, at that point we will have a plant that was completed in the early 80's. With inflation running like it is now, every one of the two plants a year after our plant is built will cost more than our plant will, because of inflation. You will have a plant that will be producing petrochemicals that will be growing at at least 5% a year rate, we will be producing less than 5% of the requirement for the Pacific basin for these particular products. We are not looking for a great part of the market. We expect to have one, two or three very knowledgable partners in different parts of this enterprise and with all of those things we think that we can have a, we know that we can have a viable project. Now a question has been raised in the course of this, even with all of this, how do we overcome the disadvantage of the hard cost of operating in Alaska? And this is a very valid question, its one we have to answer for you and its one, equally important, we have to answer for the bankers.

Now, first, we don't think that the disadvantages in Alaska are nearly as great as the construction of the pipeline would suggest.

We hope and certainly intend that we build this for far less premium than the pipeline was built for.

Second, we expect certain things that will help us to compete with the rest of the world.

Mr. Spitz mentioned some transportation cost advantages which are significant but still not enough to close the gap. The financial people they think that we can finance this with more debt than the normal project. And this is an economic benefit But even that isn't enough to close the gap. The main thing that we have to close the gap is that we will be competing at that point, at least in part, with projects that are being built in Korea, Singapore, Middle East and other places like that, that at least have some possibility of instability and some possibility of interruption of supply.

Now, the project in Alaska certainly has less of that risk. Therefore, we expect that our plant with our partners will be their favored source of supply. We don't expect anybody to pay us a bit more per pound than they pay anyone else because they can't and stay competitive. But we do expect one thing that they can give us that will not cost them anything and that is to give us a larger percent of their requirement then the average. To give us enough--this is so that we can run our plant at a higher than average rate of the other competitive plants. Now, this doesn't sound like much but just some simple facts on this kind of plant. This kind of plant has a break even point of about 70% which means that you don't make any money until it gets up to about 70% and then you start making a lot of money. And with this high break even point it means that at 80% you make some amount of money. At 90% you make twice as much money as you make at 80%. So this is a highly leverage sort of operation. Now if we can run this plant at 10% higher than the average of our competitors, we can more than make up the Alaska disadvantage even if we assume some rather large disadvantages here. Now we expect to be able to do that because the people that we will have as partners and the people that we will have as customers will want to keep this plant alive, will want to keep this assured source of supply in being to the extent that these are Japanese plants. They will want to contribute to the improvement of balance of payments between us and the Japanese.

Now, with all these factors, with the organization we have, with the partners we expect to get and with the help of the people in Alaska, we expect to be able to make this a viable possible petrochemical project and to make Alaska an important factor in this part of the industrial world.

Thank you, gentlemen.

CHARLES HONIG:

Thank you, Gordon. In closing I would like to just flash on the screen for a moment the eleven recommendations, contractual recommendations that Mr. Miles' State Energy Policy Committee made last year. We believe that ALPETCO has -- we were conscious of these, as we negotiated the contract and we believe we have met all eleven of these contractual recommendations. And those were first that the contracts have a cancellation or termination provision which ours has -- that it require local training and hire, which it does; that completion of the refinery be tied to the sale of crude to assure there would be a refinery and this exists in our contract. That the in-value price be paid which we agreed to do. That there be compliance and security provisions in the contract which there are. That the point of delivery be LACT meter one, which it is. That there be no subsidy and there is none. That the method of payment should minimize the float of the funds and I assure you it does. That in-state fuels, use of fuels, be provided for, which it is. That in-state processing be required by the contract, which it is and that the quantity not be guaranteed by the State, and it is not. Thank you gentlemen. I apologize for the length of the presentation but there has been so much talk about it over a period of time -- we assembled these people here, we felt we should address it fully. Alright, thank you very much and as we stated in our opening remarks that we needed some information (indisc.)

CHAIRMAN MILES:

Thank you. I'm tremendously satisfied and pleased with the project. I don't think there's any doubt about it, especially after what we heard today. Perhaps one of them would like to comment on how the effect of committing undiscovered reserves to the project would affect the financing.

CHARLES HONIG:

Jim?

ALPETCO REPRESENTATIVE:

Okay. Would you care to repeat that question please, I didn't quite catch it. The committing of reserves?

CHAIRMAN MILES:

Yeah, the 70%, the undiscovered -- essentially undiscovered reserves.

ALPETCO REPRESENTATIVE:

Let's try and keep this in perspective. We are going to go out and raise 2-1/2 billion dollars worth of financing. The lenders under these loan agreements are going to want to have some assurance that the debt's going to get repaid. People who we are going to sell the equity to want to be assured they are going to get a return on that equity. Now the only thing that really could happen, once they put up the money, is that the crude oil is available so that it can be processed, sold and the profits made. And I think for any types of these financing, everyone that I alluded to in my remarks, the raw material has been first, and the most key ingredient --

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you have to have the economic viability, the raw materials and the take of the product.

It's a three legged stool. You take away any one of those assurances and the stool falls down. So before anybody goes into this type of agreement on financing, they are going to have to understand that there is enough material there you can run through the plant and make the product of which the profit is going to service the debt. And so we were hopeful and we have been very hard on ALPETCO and we've lost. We wanted a 100% of the royalty oil out of Prudhoe Bay but we understood that that had already been committed and we wanted 100% of the other royalty oil because, as once again, there is no guarantee that the State can deliver oil. All you can deliver is what you get and we want to make sure for the financial viability of that project that at least you get 150,000 barrels a day of crude. Because I tell you when we shift the other way the lenders are going to say to us but how do we know we are going to get a sufficient supply of crude to be able to serve--you know, to run this refinery. Really, everything we've said is based on our supply of crude and that's really the foundation of where we start. We've got to have that supply of crude.

CHAIRMAN MILES:

Some of that is undiscovered yet.

UNIDENTIFIED SPEAKER:

That's right.

CHAIRMAN MILES:

Then your--that doesn't really--it obviously doesn't cause the financial people too much of a problem.

UNIDENTIFIED SPEAKER:

What undiscovered? Well, to the extent it continues to be discovered it will be beneficial to us. Right now the reserves that we've heard about seem to be in sufficient supply.

CHAIRMAN MILES:

Yeah, I think we all expect more oil but it is a certain, a little bit riskier than taking 150,000 known (indisc)

UNIDENTIFIED SPEAKER:

It gives us more assurance however than not having any.

UNIDENTIFIED SPEAKER:

Okay.

UNIDENTIFIED SPEAKER:

The more assurances that we can have, the better off we are.

CHAIRMAN MILES: Mr. Chatterton.

MR. CHATTERTON:

Thank you Mr. Chairman. I apparently need a little bit of clarification on an obvious misconception that I have. I believe that I heard you Mr. Lopp say that the project can be financed given its economic viability. I can understand that and I heard you, Mr. Paynter, say that subject to a satisfactory credit agreement why you could support it. Now, that's what I heard. Now, have I miscontrued this? You have not given this your stamp of financial approval yet? Is that correct?

MR. PAYNTER:

No, we haven't given our stamp of approval based on the assumptions that I made in my remarks and I think just reiterated.

UNIDENTIFIED SPEAKER:

And if I can talk to.....what I said.....

MR. HONIG:

This is Mr. Paynter ....

UNIDENTIFIED SPEAKER:

Oh, I'm sorry. That's okay. I apologize.

MR. PAYNTER:

We, of course, on the short term side look to the long term take-out and if they are satisfied, if they are able to sell to long term investors and long term lenders the note, the equity, the wherewithall then the commercial banking side of this is taken out.

UNIDENTIFIED SPEAKER:

Okay. Together with all these ifs why everythings fine.

UNIDENTIFIED SPEAKER:

That's right.

(Indisc.-interrupted)

CHAIRMAN MILES:

Mr. Chatterton.

MR. CHAT CHATTERTON:

Thank you. One question to Mr. Norris that may sound a little bit not connected with the subject dependent upon the response. Mr. Norris, your parent company is Haliburton (ph). To your knowledge

is any division or subsidiary of Haliburton (ph) engaged in the exploration for oil, production of oil and gas?

MR. NORRIS:

No, sir.

MR. CHATTERTON:

Thank you. Thank you, Mr. Chairman.

CHAIRMAN MILES:

There is a clause in the contract 2.6 Delivery of TAPS Fill by Seller, which essentially says that the State will supply trans-Alaska system pipeline fill and storage tank bottom requirements and that the State won't get paid till the termination of the contract. Twenty-seven years down the pike. How much oil is that--what actually is--what is pipeline fill and why shouldn't we get paid for 27 years? How much is it?

UNIDENTIFIED SPEAKER:

Well--this is a product (cough-indisc) our negotiations and we wanted the point of delivery to be Valdez and the State of Alaska wanted the point of delivery to be at the other end of the crude oil pipeline because they did not want to be a shipper. And all of our arguments have been for the delivery to be at Valdez. So in exchange for our agreeing to take the delivery at LACT Meter I the State agreed we could pay for the line fill at the end of the contract period or if upon termination immediately preceding termination.

CHAIRMAN MILES:

How much is that?

UNIDENTIFIED SPEAKER:

It's about -- well it's 85% of 1/8 of--in dollars it's about 9 million dollars.

UNIDENTIFIED SPEAKER:

But by the time it's ultimately paid for it will be paid for in the value of the oil at that time so if oil is $20 a barrel then it will be paid for at the rate of $20 a barrel (indisc.-interrupted)

CHAIRMAN MILES:

By unaminous consent we certainly appreciate the presentation....

(End of Meeting)

Tuesday

2. Joe Moore - Bonner & Moore

A review of their report. Added comment was that ALPETCO was:

- Most responsive to State's needs.
- Had expended the most money in its efforts to secure the contract.
- Management had improved as a result of negotiations.

Questions and Answers revolved around the following topics:

- Alaska Disadvantage: Will value added concept diminish the Alaska disadvantage?
- Profitability: Petrochemical project vs. refinery.
- Preferable Location: Alaska over West Coast
- Japanese Interest: Unstable Middle East supply; Outmoded plants.

3. Administration - Bob LeResche and Fred Boness

Bob LeResche gave a brief summary of what has transpired recently to lead up to the current contract along the lines outlined in the attached memo from Connie Barlow to the commissioner.

He added that the ALPETCO contract was the"best possible deal we could put together for the State", and that it was infinitely better than to continue to take our royalty oil share in value. He said an opportunity would not represent itself again to sell our royalty oil so favorably.

He maintained that what risks existed were minimal, and that the Administration's burdens connect with the contract were confined to:

- monitoring the contract
- site selection
- some added accounting work
- litigating storage right question
- permitting process
- measuring and testing of the crude
- enforcing local hire provisions.

Questions and Answers dealt with:

- Commitment of other royalty oil - 2.3 and 2.4 - and the ability of Prudhoe Bay to provide 150,000 b/d upon initiation of project start-up.

- Article XXII - "Referendum" Provision: Before it can go before voters it must first pass the Royalty Board and the Legislature.

- Volume: Percentage vs. specific amount. LeResche said it was a percentage, which differs from what Rep. Miles maintains.

- Extentions under Article X: They are not cummulative; they are measured from effective date. Passed this interpretation on to Randy Berry.

Alaska State Legislature

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TRANSCRIPT OF TESTIMONY OF

ROBERT E. LeRESCHE

March 14, 1978

BEFORE THE SPECIAL COMMITTEE OF THE LEGISLATURE ON ROYALTY OIL AND GAS

Committee:

Senators:	Representatives:
Mike Colletta	Chairman Bill Miles
Pat Rodey	Chat Chatterton
Bill Sumner	Joe McKinnon
John Sackett	Charlie Parr
Kay Poland	Al Osterback

CHAIRMAN MILES:

We will come back to order, Commissioner, are you ready?

COMMISSIONER LERESCHE:

Yes, sir. Shall we go, okay. Mr. Chairman and members of the committee, I'm not going to spend a lot of time today by way of background, nor am I going to go through the contract term by term, as certainly you could do that as well as we could on your own. What I would like to do is summarize the procedures that we followed over the past 8 or 9 months to arrive at where we are today and to discuss the general questions that we had to deal with in making these decisions.

UNIDENTIFIED SPEAKER:

Will you speak a little louder, Commissioner?

COMMISSIONER LERESCHE:

I can sure try. To discuss the general questions we had to deal with in making these decisions and why we came down where we did on them. First a brief summary of what's happened to

us in the past 9 or 10 months, actually is what it is. I'll start before that time, however. In May of 1975, the Department of Natural Resources issued a general interest solicitation for Prudhoe gas or oil for export or for in-state processing. Essentially this was a canvassing of the industry to see what type of interest we had in our royalty oil and gas. We sent out more than 100 letters and got I'm not sure how many responses, but not a vast number of responses. Remember, this was '75, before completion of the pipeline. Most of these responses expressed an interest in purchasing gas or oil with no in-state processing requirements. There were several, however, who did express an interest in in-state processing. These were Golden Valley, to whom we've since made a sale as you know last year; Tesoro, which at that time was thinking of expanding their Kenai refinery; North Pole, with whom we are about to consummate the contract and then Alaska Petroleum Company, one of the four final bidders in this present contract; and Cook Oil, which was suffering at the time from Canadian crude cutbacks and wanted a large volume purchase for export to their, I think, Minnesota refinery.

Given those replies and given the uncertainties of tariffs, oil pricing, etcetera, we let the matter sit for the next two years roughly. That was about a year ago. And you recall better then I do probably the events of last spring. We did approve a sale to Golden Valley. Meanwhile, both North Pole and Alaska Petroleum were putting some significant pressure on us to get on with consideration of the large volume sale. And perhaps more important, a group composed ironically of one of the present venturers was trying to force us and the legislature to make a very quick sale of Prudhoe royalty oil in order to avoid possible jurisdiction by the Federal Energy Administration. At that time they were arguing, if we didn't sell then we'd never get to take our oil in kind. As you recall, we got an opinion out of F.E.A. which made us all comfortable with our position and the fact that we can take in-kind in the future. So that is obviated. Perhaps the most important event that occurred last year was your passage of the amendments to the royalty board statute. These were very significant in that they changed the presumption under which the executive branch has to operate. From the date of passage of that we could not continue to take in-value until we considered all the alternatives -- until we'd made a finding that taking in-value was in fact preferable to the broad public interest to take in-kind. Now we took this mandate very seriously. However, there were two possible approaches. One would have been to sort of take an academic look at the whole thing, consider the problems of doing business in Alaska, consider refinery and petrochemical capacities and just conclude academically, if you will, that we might as well continue to take in-value. We did not choose

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that alternative.

The second alternative was to do what we did. And this is to lure the private sector into very significant considerations of markets and of possible projects, to lure them into doing that as part of proposals for our royalty oil. We felt that only through the private sector, through private industry look at markets and projects, could we get a proper feasibility study for an in-kind taking and sale of the royalty oil. So at that time we issued a formal solicitation for a large volume sale of Prudhoe Bay crude. Concurrently, the Royalty Board adopted 8 policies after hearing from some of you in testimony -- taking testimony from the Governor and others, and we adopted policies regarding price preference for in-state use and things like that. We then told the firms that received the solicitation that we would make decisions based on these policies. Our first deadline for preliminary proposals was August 1st, 1977. At that time we received 10 responses, some of which involved expenditures of several hundred thousand dollars at the outset for preliminary feasibility studies. We considered these very carefully and established a date in October whereby we wanted final concept proposals which would include draft contracts. After August 1st I sent out another letter to all legislators and interested parties throughout the state, discussing in some detail the issues as we saw them that were growing or evolving in this sale. This included a discussion of eleven objectives and a statement of how we proposed to carry out these objectives and a request for your comments on those. The objectives included volume -- that is as that time we said we would not sell more than 90% from the Prudhoe field; a policy, or an objective, that we did not wish to deliver crude before a facility was in place; an objective that we would favor the highest value added, all else being equal in the product state; an objective that we favor the largest facility possible within the constraints of optimized project economics; objectives regarding price; environmental controls, citing penalties and terminations under the contract; the role of the state in advocating permits etcetera; resident and minority hire objectives and in-state sales and prices of in-state products.

After the comment period, we proceeded with trying to negotiate all these objectives into the contract. We also sent the original 10 bidders detailed critiques of their proposals, comparing them with these objectives and clarified certain things such as volume and other things and outlined requests for the final October submissions. As a result of that, we came down to the four proposals. Municipal Utility Systems, which is one of the first respondents, withdrew. Tesoro withdrew. Pacific Resources withdrew, the Board rejected Energy Resources Incorporated of Salt Lake and Commercial Realty of Los Angeles for insignificant or inadequate final proposals. Following this -- we're down to the four proposals. We discussed these in hearings with Chairman

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Miles' committee and then proceeded for the following three months into intensive negotiations which resulted, as you know, about in the middle of February with our choosing ALPETCO as the best possible deal that we could put together for this state after all this time in light of real circumstances. We also concluded unequivocally that the ALPETCO contract before you now was infinitely better than a continuing to take in-value over the long term.

Now I'll just step back from that a little bit and mention briefly what the ideal contract would be. That is the ideal contract in the ideal world. The ideal contract maybe in the economists' world. I think we have the ideal contract in the real world, but what we started out to get was something different. That ideal contract under circumstances which certainly do not exist today would have been a contract with one of the major oil companies, or chemical companies, with an absolute commitment to build this facility with liquidated damages negotiated in. I'm not afraid to say we're unable to get that given all the world conditions that you've heard about for the last two days. It became clear that this was impossible. Royalty oil is expensive oil. There's no cut rate royalty oil under our pricing policy. Furthermore, the price is still undetermined, although it's much more determined than it was two years ago. The volumes that will be available are still undetermined, even with the option clause. Further, there is this theoretical disadvantage of doing business like this in Alaska, which is something else we had to take into consideration. The alternative to this ideal contract, and I think the best alternative in the real world, is a contract such as we've negotiated. This is a contract which minimizes the risks to the state and puts maximum incentives on the buyer, the private entity with which we want the state to contract, puts maximum incentives on them to make the project work for the benefit of not only their own pocketbooks, but all the people of the state. With that in mind I will just underscore what all of you know, the critical term in this contract is the performance term, Article X in which ALPETCO promises what they'll do, promises what they'll expend and promises what incentives they have. That, together with the security terms, does in fact leave the state virtually riskless and gives ALPETCO the greatest incentives that we could derive. To simplify — ALPETCO's going to spend at least 10 million dollars over the next 18 months. They have to or the contract will be summarily cancelled. No one -- least of all the firm made up of listed firms is going to throw away 10 million bucks. They want it to fly as much or more than we do. If they don't get financing after this best effort, we get the oil back -- we've never lost it in fact by that time, we're left riskless. But basically we've negotiated that some

of the strongest people in the private sector will put their best efforts and their good money into making this work for the people of the state and that's what the contract is all about.

Now when you talk directly about the risks to the state -- there's been a lot of talk about a riskless contract. This is not a riskless contract. There is no riskless contract as far as I'm concerned. Nothing can be riskless and commit you for more than the next thirty seconds. There are risks inherent. I submit that these risks are very minimal compared to the extreme benefits that are possible under this contract. Let me just run down the supposed risks. There is an added administrative burden to the state if this contract is approved. No question about it -- it's a minor burden. The state would have to monitor the contract, we'd have to participate in site selection; we'd have to do some accounting as volumes of taking changed, whereas we don't have to do that now, taking in-value. We're required to litigate the storage question. We're required, as a state, to consider all the permits that these people are going to need as we would with any development project. We have some requirements to assist ALPETCO in looking at the measuring and testing, which is not a major thing; to assist ALPETCO in obtaining crude oil assays, which is not major; to help the buyer design the training and resident hire programs and to help them implement those,which are functions of the government as it exists now. Another supposed risk that we enter under this contract is the fact that we do in fact lose the option to do something else with this oil in the next 18 months. Now apparently Legislative Affairs asked Botel (ph) to consider this, you'll hear from them I think tomorrow. Basically there's nothing else to do with the oil in the next 18 months. The way I understand it, Botel will reconfirm that. In fact, this contract is a culmination of a very thorough and expensive search for alternatives as to what to do with this oil. None others have come up -- this is the best alternative. So the fact that we can't sell the oil to anyone else within 18 months, I do not think is significant. Two terms of this contract allegedly put the state under some vague future risk and I want to just briefly address these directly. These are 2.3 and 2.4, the infamous option terms.

2.3 is not an option term per se, but it is right of ALPETCO to have the opportunity to purchase any other state royalty oil which is cheaper at their refinery gate than Prudhoe oil --if they then reduce their Prudhoe purchases by a like amount and only after their facility is on line. This is a

term they insisted on to protect them from another refinery or another petrochemical facility running them out of business using cheaper state royalty oil from right next door. It's a reasonable term. It does not burden the state. If they take this cheaper oil, they return the Prudhoe oil to us. There seems no benefit to the state to make it possible for someone else to drive this facility out of business which will, before this term can ever come into effect, be an existing in-state facility, which as you all know, rationally and politically we'll all be very pleased to protect. The other option term is 2.4. This is a term that gives ALPETCO the right to purchase up to 70% of any future royalties from other fields up to a ceiling of 150,000 barrels per day, aggregate ceiling, that is Prudhoe, plus these other sources. This also only comes on line once the facility is on stream. I think I might have misspoken on 2.3 but it's not significant now. We can go back to that. At any rate, this comes only once the facility is on stream. Now there's some vague fear about this and I'm not sure why, once we think it through. Before this term even applies, ALPETCO will be an existing in-state facility. Our statute requires that we not sell oil except as surplus to in-state needs. ALPETCO will be an in-state need at that time. Our policy says we'll favor existing in-state facilities without alternate sources. All we're doing is contracting what we would intend to do anyway and contracting what I submit we would do without fail anyway. Picture us ten years hence, a very large industry in the state running short of crude -- picture us selli alternate crude to someone else. We wouldn't do it. All this does is contract that we won't do it. In fact, it does better than that, it very clearly states that we would intend to withhold up to 30% for other potential uses. The 70% is not something ALPETCO wanted but we did preserve the option to the extent of 30%. But I submit you think this through. The option doesn't take effect until Alaska -- or until ALPETCO -- is an on stream facility in the state, an established in-state need. With that in effect, why would we sell to someone else anyway.

CHAIRMAN MILES:

Isn't that a Catch-22 though Commissioner?

COMMISSIONER LERESCHE:

No.

CHAIRMAN MILES:

You say we're committing it now and then down the line, there will be an in-state need to which we are committing ourselves, so it's okay to commit it.

COMMISSIONER LERESCHE:

I don't follow that,Bill?

CHAIRMAN MILES:

Well I don't either.

COMMISSIONER LERESCHE:

This term does not commit it unless there is an in-state need, by definition. If they don't come on line, the term doesn't apply.

CHAIRMAN MILES:

Go ahead, we'll get back to that.

COMMISSIONER LERESCHE:

Okay, I don't think it's a Catch-22 at all. What people seem to ignore is that this term doesn't even trigger until there's an in-state need. It's by definition, it's not a Catch-22.

Okay, all I'm saying is this term really contracts to do what we would do anyway and I think it's a good term. I'll tell you frankly, we're trying to get the term out of there for just the reason the people are objecting to it. It's difficult to understand. We're unable to excise that term. So, those as I see it, are the generally vague and/or insignificant risks that the state takes under this contract and I'd just ask you to compare these risks with what you've heard the last day and a half regarding the benefits, the job benefits, the increase in the in-state fuel capacity benefits, the tax benefits, the benefits of the trust fund, the benefits of having the state involved as a proprietor, not just a regulator in such things as local hire, job training and environmental affairs. So just to summarize what I've said, we're instructed by the legislature to explore all the alternatives to taking in-value. We did this, let us say, with a vengeance. We got private industry to spend hundreds of thousands of dollars exploring these alternatives within our stated criteria in terms. We put together the best deal possible through negotiation, given the present and predictable circumstances. This deal has a very high potential of benefits for the citizens of the state and it has minimal risks to the citizens of the state. The

contract relies entirely on private sector initiatives and mechanisms to put the facility together and to operate it. I think this is important. It does not make the mistakes that the come by chance refinery in eastern Canada made of getting the government involved financially in it. But it creates incentives for private enterprise to put it together, that's how we wanted it. It seems to be only prudent for the legislature to confirm this sale as a solid epitome of the purposes of the entire concept of why the state retains a royalty interest as a lever for achieving more than can be achieved just with the money we would get by selling the oil at the wellhead. Prudhoe is being produced. An opportunity like this is not going to knock again in the very near future. And I, of course, recommend very strongly that we take this opportunity now.

SENATOR SUMNER:

Mr. Chairman. In 25.2, in regards to local training, who in the administration negotiated that section? When they talk about $500,000 as having fulfilled their requirement (indisc. -- cough) in 10 years or that an aggregate of 1 million dollars had been expended from all sources, including federal, private and state funds on said program on or prior to 10 years from today, who negotiated that?

COMMISSIONER LERESCHE:

This was proposed by the Department of Labor and the Department of Law and Mr. Boness and I negotiated it. If you're implying that the numbers are low, I submit that they're not all that low. I submit that as part of the whole contract, but basically I submit that this firm includes six Alaska native corporations. And to me that's the best guarantee of all that this firm will be dedicated to local training and resident hire. I think that's a better guarantee than negotiating a very complex and (indisc.) term under the contract. But basically Senator, this was the best we could do in the total context of the contract.

SENATOR SUMNER:

I understand, but out of our committee already, we're asking for a million dollars in terms of expanding the Seward Skill Center to address some of these problems and when you talk about federal, private and state funds, essentially they're out from under the gun even before their own stream. These funds will -- this is by no means the magnitude at which the training -- if we are to

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even in the period of ten years. We'll have no recourse as a result of the contract.

COMMISSIONER LERESCHE:

Well I think Fred wants to reply also, but I think you could understand why they were not anxious to negotiate an open ended commitment in the thing. That wouldn't have been prudent for them. Fred.

MR. BONESS:

I would just add in response to that that from a lawyer's point of view, if there's no threshhold in there but simply commitment to local training and then there are allegations that that commitment isn't being lived up to, it becomes very difficult to determine whether a breach of the contract has occurred or not. And it was my recommendation that from the point of view of a lawyer or somebody looking at it in terms of the legals construct, some minimum would at least give you a threshhold test and it was intended to be just that, a minimum -- not a maximum, a threshhold test with respect to whether or not they were making an effort or not. If we left out the last part of the term which refers to dollar amounts, it would be much more difficult to determine whether or not a real commitment was made. Now I understand what you're saying about the amount of money. I would point out two things in that regard. First of all this money refers to training specific to the project. The million dollars for the Seward Skill Center, some of that may refer to training that would be adequate for this project and some of it may not so that this is not necessarily -- this million dollar commitment cannot fully be covered by actions of the legislature with respect to its overall commitment.

Beyond that I think your objective and ours is both simply one of insuring that training does take place. I don't think you particularly feel that it must be ALPETCO's responsibility to do the training, if indeed some other company or some other government body said we believe that's our responsibility and we see this project coming on line and are going to do it. So I think the contract was intended as Commissioner LeResche said, to reflect a commitment, but not necessarily to put the full responsibility and burden upon them.

SENATOR SUMNER:

Okay, but it wasn't intended to exclude them, either?

MR. BONESS:

No, definitely not.

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SENATOR COLLETTA:

Okay, then the other part of my question is, how much consideration and what was the determination that was made on that consideration as to -- how does this commitment for the future weaken our future lease sales?

COMMISSIONER LERESCHE:

Lease sales? I don't see any connection.

SENATOR COLLETTA:

Because the availability of the buy back of the state's share in value certainly has to be a carrot for anybody bidding on something. (Indisc.)-- gas situation with Phillips. We were forced to go and drill another well because we decided to take that gas.

COMMISSIONER LERESCHE:

Okay, the answer is it weakens it to the extent that any royalty sale weakens it -- to the extent that the royalty statute weakens it. Certainly a lease purchaser would prefer to have 8/8's instead of 7/8's. This is a signal that we intend for them to only have 7/8's. I don't know how to calculate how much that weakens it, but that's been the state's policy since the royalty statute was established.

SENATOR COLLETTA:

And one other question probably to you is, in 2.4, was that applicable only to Prudhoe Bay -- the one phrase, and I don't remember the line and page but we had in all production that the state has an interest in, in fact then would Cook Inlet be eligible for delivery (indisc.)?

COMMISSIONER LERESCHE:

Under 2.4, yes.

SENATOR COLLETTA:

Okay, aren't we taxed to the maximum now in Cook Inlet with Tesoro?

COMMISSIONER LERESCHE:

There's an express exemption for Tesoro.

SENATOR COLLETTA:

(Indisc. - simultaneous speech).

COMMISSIONER LERESCHE:

But we are delivering all of our royalty oil to Tesoro. This contract would not interfere with that contract.

SENATOR COLLETTA:

No, but it would become eligible to delivery of oil. Would it not?

COMMISSIONER LERESCHE:

No.

SENATOR COLLETTA:

2.4 is inclusive of all state interests in production?

COMMISSIONER LERESCHE:

All state interests except Tesoro, North Pole and Golden Valley, which are explicitly mentioned in here. If there's new Cook Inlet reserves discovered, they would come under 2.4, the leases from which Tesoro is presently purchasing royalty would not come under it.

SENATOR COLLETTA:

Thank you.

CHAIRMAN MILES:

A couple of questions have recently been raised about the legal background of the contract. I don't mean questions arising from the non-winning bidders. Can you just give us an idea what legal basis you progressed -- legal background that went on for the contract?

COMMISSIONER LERESCHE:

I guess -- you mean for procedures that were used?

CHAIRMAN MILES:

Yes. And -- yeah. What did your lawyers say and do and who were they?

COMMISSIONER LERESCHE:

They were Fred, although I'm not sure that he can officially be an attorney any more, Cynthia Pickering (ph) and Jeff Hanes (ph), plus we retained Gene Kline (ph) from Phillips and Iser (ph) firm in New York to look at the commercial and

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security sections of this. Fred could deal with -- I don't really know what the questions are. As far as I'm concerned we followed the statutes perfectly well. There was nothing even shadily illegal about this.

CHAIRMAN MILES:

I think you're reading something more into my question. Has the Attorney General signed off on the contract?

COMMISSIONER LERESCHE:

Yes.

CHAIRMAN MILES:

He's approved it and so we're all -- during the course of negotiations did you discuss royalty oil contracts with other states?

COMMISSIONER LERESCHE:

No.

CHAIRMAN MILES:

Why not?

COMMISSIONER LERESCHE:

Didn't feel any need to.

CHAIRMAN MILES:

Did you review royalty oil contracts from other states?

COMMISSIONER LERESCHE:

I assume that the attorneys did.

CHAIRMAN MILES

Which ones?

MR. BONESS:

California has a contract which they use from time to time and I'mtold Louisiana attempted a deal somewhat similar to this,

although I have not seen the contract that they put together, if in fact they tried to put together a deal that never went through in Louisiana.

CHAIRMAN MILES:

The reason that I raised the question -- go ahead please.

COMMISSIONER LERESCHE:

I would point out that to my knowledge and I've certainly not made an attempt to canvass it, but no other state has a royalty statute at all similar to ours in terms of the obligations it places upon either the executive or the legislature with respect to the sale of royalty oil. The federal government, for example, sells oil through U.S.G.S. it's sort of -- under a standard form contract and there are regulations, federal regulations for the sale under that. I believe California operates under a procedure quite similar to that -- the sale is made by the lands commissioner. In no other situation are there quite all the steps or quite all the burdens or implications, they may not necessarily be burdens, set forth. So I'm not sure other states, or the federal government's contracts, or even private contracts are particularly helpful, I don't know. All the contracts that I know about are essentially posted price contracts, calls for oil. They're straight buy/sell oil contracts. Ours -- this contract is really two contracts. It's purchase and sale of oil and it's a commitment to construct a facility and do various other things for the state.

CHAIRMAN MILES:

Well the reason I'm asking, I've gone through some other contracts of royalty oil sales from other states and the language, the tone of the other contracts, is substantially different from the tone of this contract. For example, one contract says that if somebody would make the state a better offer, the person taking the oil at that time can meet that offer. If they don't meet the offer, they can sell to the other company -- to the higher offer. And that's -- that would substantially be in the state's interest to have language like that.

COMMISSIONER LERESCHE:

Sure, if the only thing involved was price for the oil, it would. Given that a lot more is involved, I can't see how we could practically put that in.

CHAIRMAN MILES:

Well I think it's something that should have been considered and there's other royalty oil contracts that call for premium payments. Bonus payments.

COMMISSIONER LERESCHE:

Okay. We considered bonuses, we considered premiums, we considered price hikes, the whole thing. We considered all those without considering specific -- at least without myself personally considering specific other state royalty contracts. When you're buying and selling a commodity over a short term, you can build all that sort of stuff in. When you're putting together a very large, long term development project, those things are not feasible.

CHAIRMAN MILES:

Well why wouldn't it be feasible if the value of the oil is going up substantially, at least Milton Lipton's theory being that availability is more important than pricing, why wouldn't a premium inflator be feasible? I disagree with you there.

COMMISSIONER LERESCHE:

I can't imagine what you're thinking. This price is tied to the general price of oil. I mean it's our wellhead price as well back from what people are getting for it. It reflects the inflator price of oil, which also reflects the scarcity value of it.

CHAIRMAN MILES:

We've heard for two daysnow that one of the major aspects of the sale of this oil is that it's a domestic supply. Was it impossible or did you bring it up with the bidders, the possibility of paying for that, paying for that benefit, that it is an assured twenty-seven year supply? When the price of oil goes up, we get more than (indisc.)?

COMMISSIONER LERESCHE:

We certainly did and this contract reflects that they certainly have paid for it.

CHAIRMAN MILES:

I'm saying over and above the average price, the weighted average price?

COMMISSIONER LERESCHE:

This is above the weighted average price.

CHAIRMAN MILES:

How much?

COMMISSIONER LERESCHE:

It depends on conditions outside. It's tied to the weighted average but it's above it. It's essentially the west coast price as calculated in the leases.

CHAIRMAN MILES:

Well, okay.

COMMISSIONER LERESCHE:

-- which is far above the weighted average price. They also took the risk of paying any added charges that are added on by virtue of taking in-kind, which is something that costs them something, I'm sure.

CHAIRMAN MILES:

But he can't put a price on it?

COMMISSIONER LERESCHE:

No, because it's a probability judgment.

CHAIRMAN MILES:

Chat do you want to follow on that?

MR. CHATTERTON:

Well, no, I'll let anybody else who wants to follow, because I'm going to change the subject, but I will ask one question and I don't have it here but it's (indisc.) on your pricing schedule, is the price that we're going to receive for our royalty oil the weighted average?

COMMISSIONER LERESCHE:

No. Kirt could explain it. He's got the explanation down to about 8 minutes. I'm sure you'll understand it. It's the weighted average of the price paid by each producer but it's not the weighted average of the price they get.

MR. CHATTERTON:

Right, okay, but it's not the west coast price either?

COMMISSIONER LERESCHE:

That's what it boils down to. No. Because Sohio, for example, doesn't pay what they're getting for their oil, they pay what the other producers are getting, which is the west coast price.

AGO 545561

The other producers pay what they're getting. Each producer pays the highest of four things; their actual market price; the market value; the prevailing price, which is the price all the oil producers are getting; or the posted price, which of course doesn't exist. So it calculates roughly to west coast price because of ownership percentages and things like that.

MR. CHATTERTON:

I'll do my homework. Mr. Chairman, if I may, I have a question but it would change the subject.

CHAIRMAN MILES:

Go ahead.

MR. CHATTERTON:

Thank you, Mr. Chairman. Commissioner, Article XXII, where was the genesis of Article XXII? Or what was the genesis?

COMMISSIONER LERESCHE:

Okay. Yeah, the genesis came from two places. The first sentence was initially in there. There might be minor amendments, immaterial amendments, but any amendment, we just wanted to be very clear, had to pass the Board and the legislature. The second part came directly from the Governor. He said I want another roadblock ahead of increasing the price. Basically any contract can be amended by the Board -- well the Commissioner, the Board and the Legislature. The Governor asked that we put in another hurdle, that being the people. That's where the second sentence came from.

MR. CHATTERTON:

Mr. Chairman, if I may continue. Commissioner, don't you have concern about that section and concern along these lines -- I think we've all witnessed the media campaign, propoganda campaigns that are mounted that can sway the opinion of the people even to the point of where they might vote against their best interests? Do you have concern about that?

COMMISSIONER LERESCHE:

No, sir, I don't. Because it still has to go through the Executive Branch, the Royalty Board and then the Legislature before it even gets to the people. Now without this clause it would have to go through those three and then it would be fact. Certainly as you experienced recently, people can put

a media campaign on you that might or might not influence the Legislature to do something. This just puts another roadblock in front of it, four instead of only three.

MR. CHATTERTON:

If I may continue, Mr. Chairman. Do you suppose that this very phrase about the referendum is one of the prime reasons that the Governor can now support this sale?

COMMISSIONER LERESCHE:

I don't know how to answer that. He directed that that be put in there.

MR. CHATTERTON:

I'm wondering without it if he could still support this thing?

COMMISSIONER LERESCHE:

I didn't presume to answer that. It's a good contract without it. This just puts another shield, another floor under the price.

MR. CHATTERTON:

Thank you Mr. LeResche, thank you Mr. Chairman.

CHAIRMAN MILES:

(Indisc.)

MR. PARR:

If I might call upon the same question. I guess it disturbs some people as to why there's any consideration given at all to the reduction in price. If there's no possibility of reduction in price, you wouldn't need anything by referendum.

COMMISSIONER LERESCHE:

That's correct.

MR. PARR:

So why have it in there at all? If we was just told Commissioner the price is going to be the same, it's going to be the west coast price etcetera, etcetera.

COMMISSIONER LERESCHE:

That's right. With no mention, the thing would be open to amendment by only three bodies, the Department of Natural Resources, the Royalty Board and the Legislature. There's no way to write a contract that's not amendable. If you say this contract is not amendable, then you just amend out that sentence. It's a labyrinth, but as far as I'm concerned this is the highest level of protection that it's possible to put into a contract. The Legislature can change laws, you know, I think this is the most layers between ALPETCO and the price reduction that we could conceive of.

MR. PARR:

You didn't find it -- I guess ALPETCO, didn't find it necessary to have any layers between that and a price raise? Why are we mentioning only a price reduction, in other words, and not mentioning an upward adjustment? That's the real question, That's what is disturbing the people. It isn't the fact that you put the referendum in there. It's the fact that you mentioned a reduction and you didn't mention the increases.

COMMISSIONER LERESCHE:

That's right. The increase can be handled by four parties, ALPETCO as one of the signers of the contract; the Executive Branch; the Board and the Legislature. Frankly it's good negotiation. We don't want the people to necessarily vote on the price raise. It's easier to get a price raise than a reduction, let's say.

MR. PARR:

The implication from that, of course, is there will only be negotiations regarding a price reduction. It's just that simple. It's not intended that way, but that's the implication.

COMMISSIONER LERESCHE:

No. Okay.

MR. PARR:

No question about it.

COMMISSIONER LERESCHE:

Okay, I guess I understand that.

CHAIRMAN MILES:

Commissioner, on what basis did you -- I presume -- did you make a finding that Tesoro would service the in-state needs?

COMMISSIONER LERESCHE:

On the basis of the study that I think ISER did for the Royalty Board and on the basis of the contract. The only period of time in which this oil could be conceivably be going out of the state is the time from 18 months until the facility is on line. Clearly we will have a large surplus of crude oil for in-state needs during that period. Once this facility is on line, it's an in-state need and there's no question, because it's not going out of the state.

CHAIRMAN MILES:

Every time you say that. Obviously, I have a different feeling about that.

COMMISSIONER LERESCHE:

Well put yourself in 1985. ALPETCO's on line, there's an in-state demand, what's the lack of logic there?

CHAIRMAN MILES:

Well we're making the commitment now, Commissioner, this is 1978. You're asking us to make the commitment now. You can't justify future in-state needs 7 years down the line, now. So I'm saying it's going to be an in-state need 7 years hence. Now that's putting the cart before the horse and tipping it upside down.

COMMISSIONER LERESCHE:

Well, I disagree. How can we ever enter a contract for more than a microsecond then? You have to make some assumptions. And this is more than an assumption. It's contracted. It's not sold unless it's an in-state need.

CHAIRMAN MILES:

Back on the legal problems. Did the Royalty Board give you written approval of the sale of non-Prudhoe oil?

COMMISSIONER LERESCHE:

Yeah, they approved the contract.

CHAIRMAN MILES:

Well don't you have to have a finding, specific finding made and --.

COMMISSIONER LERESCHE:

They made five or six specific findings.

CHAIRMAN MILES:

But didn't all those findings and all those resolutions relate to specifically as with the proposal that went out. The proposals that went out were just for the sale of Prudhoe oil, right?

COMMISSIONER LERESCHE:

They weren't exclusive but they didn't specifically include more, you're right.

CHAIRMAN MILES:

So that means they were just for the sale of Prudhoe oil?

COMMISSIONER LERESCHE:

No. That means they were explicitly -- they didn't explicitly exclude other oil; they didn't explicitly offer other oil.

CHAIRMAN MILES:

Yeah, they didn't offer any other oil. What they offered for sale was Prudhoe oil?

COMMISSIONER LERESCHE:

That's right.

CHAIRMAN MILES:

No other oil?

COMMISSIONER LERESCHE:

That's right.

CHAIRMAN MILES:

Okay, I can't find where you have the authority to go ahead and sell that without written approval of the Board.

COMMISSIONER LERESCHE:

We have written approval of the Board.

CHAIRMAN MILES:

Is that right?

COMMISSIONER LERESCHE:

Yeah.

CHAIRMAN MILES:

Because the resolutions that waive the bidding procedure all seem to speak to Prudhoe oil only.

COMMISSIONER LERESCHE:

They speak to this contract.

CHAIRMAN MILES:

Which one?

COMMISSIONER LERESCHE:

This one.

CHAIRMAN MILES:

Which resolution?

COMMISSIONER LERESCHE:

All of them.

CHAIRMAN MILES

Well I have the resolutions here. It seems to speak to Prudhoe oil only. I've got eight of them. And I'm just wondering if we're going to run into a legal problem there if there wasn't any official finding and the law wasn't completely complied with?

COMMISSIONER LERESCHE:

Okay.

CHAIRMAN MILES:

We've got a legal opinion that says that.

MR. BONESS:

We haven't had the benefit of that opinion.

AGO 545567

CHAIRMAN MILES:

I didn't until yesterday either. You'll certainly want to have a copy of it.

COMMISSIONER LERESCHE:

Yesterday. Well we could do several things. We feel -- Jeff, Jeff Hanes (ph) and Fred feel that we have no legal problem. I doubt it's significant enough a problem that it couldn't be corrected at the next Royalty Board meeting. It would be nice if we could have the opinion sometime though.

CHAIRMAN MILES:

Yeah. I just got it yesterday, myself.

CHAIRMAN MILES:

Joe.

MR. MC KINNON:

Did I understand you to say that the purpose of 2.3 is to prevent any sort of competitive pressure on ALPETCO from another in-state facility?

COMMISSIONER LERESCHE:

Using royalty oil, yes.

MR. MC KINNON:

Is that a wise policy to give ALPETCO a veto over other projects within the state?

COMMISSIONER LERESCHE:

Not a veto, a chance to meet the price.

MR. MC KINNON:

Well the practical effect which may be the vetoing of another feasible facility.

COMMISSIONER LERESCHE:

Not necessarily. It will release a barrel of Prudhoe oil for every barrel they get under that. And it's tied to the value at the refinery gate. But you're right. The fact of it is that they did not want another firm to be able to come in and drive them out of business using state royalty oil.

AGO 545568

MR. MC KINNON:

How is the financing of the economics of this, let's say second refinery, could be entirely different. It's going to depend on the fact that they may be getting state oil cheaper than the oil ALPETCO will be getting doesn't necessarily mean that the final product they're going to be producing will be any cheaper than that which ALPETCO is coming up with.

COMMISSIONER LERESCHE:

That's right.

MR. MC KINNON:

And yet we're giving them veto over this even though necessarily it doesn't mean that the low price will (indisc. -- cough) the second company to undercut.

COMMISSIONER LERESCHE:

That's correct. I still say it's not a veto, but it's a chance to meet the price.

CHAIRMAN MILES:

(Indisc.)

MR. PARR:

Just a minor point, Mr. Commissioner. I think you said a while ago that you already have a contract with Golden Valley and you're about ready to close one in North Pole, right?

COMMISSIONER LERESCHE:

Yeah.

MR. PARR:

That contract with North Pole, is there -- looking down the road as far as we can reasonably see -- will the contract with ALPETCO cause any problems for North Pole, getting as much oil as it needs?

COMMISSIONER LERESCHE:

No sir, I don't think so. Fred could speak more to that, he's been negotiating with --.

AGO 545569

MR. PARR:

In a sense, they were here first. They didn't waif any kind of guarantee from the state. They came in and built their refinery -- not as big a one, I realize, but nevertheless they stuck their necksout, came into the state and here they are.

COMMISSIONER LERESCHE:

That's correct and we in fact backed all of the other proposers back off the 90% to 85% in recognition of that fact.

MR.PARR:

In other words there's no problem with them getting what they'll need if this contract goes into effect?

COMMISSIONER LERESCHE:

As far as I'm aware, they're pretty much, if not totally, satisfied with their volume term and this -- 15% will certainly be significant to them.

MR. PARR:

Thank you.

CHAIRMAN MILES:

Commissioner, by essentially guaranteeing a specific quantity of oil -- this is a subject that -- I don't know if you were here yesterday, but the ALPETCO people and I disagreed on -- I certainly feel that there's a specific quantity guarantee, they seem not to think that but -- what effect will that have on our regulatorypowers insofar as we do to some extent control the rate of flow? Doesn't that -- won't we be sacrificing or isn't the position very, very possible we'll be sacrificing what's in the best interests overall of the State of Alaska for some economic concessions just to get up to 145,000, 150,000 barrels a day?

COMMISSIONER LERESCHE:

Any commissioner or any oil and gas conservation committee or any oil and gas conservation commission who could allow those things to influence their conservation decisions ought to be summarily dismissed. There would be no excuse for such a thing.

CHAIRMAN MILES:

Well that's in fact -- we know that doesn't happen, nobody gets summarily dismissed.

COMMISSIONER LERESCHE:

Nor, I don't think we've ever made a decision for our proprietary interest which reneged on our conservation regulatory responsibility.

CHAIRMAN MILES:

Yes, but it's a strong possibility, isn't it?

COMMISSIONER LERESCHE:

No, what if we don't have a contract. We've still got to monitor the interest in royalty.

CHAIRMAN MILES:

Well, we're talking about -- we're assuming that we do have a contract. That's why we're all here.

COMMISSIONER LERESCHE:

I'm saying the problem exists with or without this contract. If there's a problem.

CHAIRMAN MILES:

But doesn't it exist to a much more severe degree?

COMMISSIONER LERESCHE:

I don't think significantly more severe. Certainly if there's an industry in the state that uses 150,000 barrels of crude a day, there's pressure built to produce crude for that industry. But that's just inherent in our dual role of regulator and owner.

CHAIRMAN MILES:

Well it relates to, again, the initial point of should we be selling a quantity or a percentage.

COMMISSIONER LERESCHE:

Yeah, Bill, we're selling a percentage with a specific ceiling on the percentage, that being 150,000 barrels.

CHAIRMAN MILES:

But let's face it, we're essentially guaranteeing up to 150,000 barrels, regardless of -- you can call it what you want, but

that's essentially what we're guaranteeing is 150,000 barrels.

COMMISSIONER LERESCHE:

No, we're saying -- we're guaranteeing 85% of Prudhoe, 70% of any others, but never to exceed 150,000 barrels. We're guaranteeing percents.

CHAIRMAN MILES:

So ALPETCO gets 150,000 barrels?

COMMISSIONER LERESCHE:

If we have it.

CHAIRMAN MILES:

Yeah.

COMMISSIONER LERESCHE:

We're creating a demand for it, no question about it. But if all we have is Prudhoe and if 85% of it is 100,000 barrels, we haven't guaranteed them 150,000 because we don't have it.

CHAIRMAN MILES:

Yeah, I understand that. But if we have it, we're guaranteeing 150,000?

COMMISSIONER LERESCHE:

That's right.

CHAIRMAN MILES:

Right. Okay.

COMMISSIONER LERESCHE:

Well if we have it within the 85% --.

CHAIRMAN MILES:

Within the 15 and the yeah, I understand. Well that's just a philosophical difference, I guess.

COMMISSIONER LERESCHE:

Metaphysical.

CHAIRMAN MILES:

No, I can't spell that. It just seems like we're really putting

the fox right in the chicken coop.

SENATOR SUMNER:

Mr. Chairman, yesterday you asked that same question and I was under the impression, the way you were wording it, and again todays -- if under all the worst possible circumstances coming about, would we still be required to deliver that 145 or 150,000 barrels a day. It's my understanding that that would not happen if all the positive things flow and the yield is such that the percentages as outlines in here would come up to 145 or 150,000 barrels a day. To that extent, they would be guaranteed that take. But at the same time that guarantee limits them to 150,000 too. But under the worst of all possible circumstances and the flow rate was not such, that this percentage yield 150,000 barrels, the state would not be guaranteeing that. We wouldn't have to go and buy from somebody and --.

CHAIRMAN MILES:

No, no. But my point is that the flow rate, you just mentioned, can be changed to deliver that -- to require the state to deliver 150 thou.

SENATOR SUMNER:

But this wouldn't do it here?

CHAIRMAN MILES:

Oh, it would do it as much as anything else.

COMMISSIONER LERESCHE:

Mr. Chairman, I'm sure you understand the procedures whereby these flow rates are established and being sure that you understand that, I can't really understand your question. They are totally unrelated to this whole deal with the exception that it's regulated by unit operators and state employees.

CHAIRMAN MILES:

By state employees, yes, well that's a strong relation.

COMMISSIONER LERESCHE:

But it's about as far away as you can get, given that their both state employees. We were talking about that earlier.

CHAIRMAN MILES:

(Indisc.)

AGO 545573

MR. CHATTERTON:

Mr. Chairman, I'm going to diverge again and come back to -- and I hate to have you take the 8 minutes, Fred, shorten it here -- but on this pricing, let me set up a scenario here, a very simplistic situation. Let's say 25% of the gross production from the field (indisc.) carries a wellhead value of $6.00 a barrel, 50% of that production carries a value -- wellhead price of $5.00 a barrel and 25% carries a wellhead price of $4.00 a barrel. Now the weighted average to that of the whole 100% barrel is going to be $5.00 a barrel, right?

UNIDENTIFIED SPEAKER:

Right.

MR. CHATTERTON:

We're to gather. Now that would make our 1/8 worth $5.00 a barrel and the operating company's 7/8's worth $5.00 a barrel, we're all together here, this is wellhead price.

MR. BONESS:

May I interrupt just for a second?

MR. CHATTERTON:

Yes.

MR. BONESS:

I don't believe you can do this kind of calculations without also assigning different incomes to different companies because that comes into it, but I'll follow through with your example before I explain why I think that's so.

MR. CHATTERTON:

Okay, you're going to confuse the heck out of me, Fred.

COMMISSIONER LERESCHE:

It's how you get the wellhead value, not how you average it out once you have the wellhead value. That's the big question.

MR. BONESS:

Why don't we go through the rest of your example and then I'll come back and explain to you.

MR. CHATTERTON

Let me go through the rest of my example to clarify one point in my mind then you can confuse the heck out of me.

AGO 545574

MR. BONESS:

Okay.

MR. CHATTERTON:

Okay. Alright. So here we have our 1/8 and their 7/8's is worth $5.00 a barrel at the wellhead. Now, so far as I know, why -- yesterday we had quite a point was made of the purchase point was the L.A.C.T. meter. I submit that 7/8's of this barrel is produced, or 7/8's of the production of any one day here, is now worth $5.00 a barrel at the L.A.C.T. meter. We are in court as to whether our 1/8 is worth $5.00 per barrel. Now what if we lose that court case? In other words what is ALPETCO going to pay us at the L.A.C.T. meter?

MR. BONESS:

Okay. For the purposes of your question -- I don't have any problem assuming that the L.A.C.T. meter 1/8 is worth $5.00. Now, if we lose the court case and the court says you value royalty oil at the flow station, let's say, then the state will have to pay the producers a certain amount of money to get it from the flow station to the L.A.C.T. meter. We will still deliver to ALPETCO at the L.A.C.T. meter, they will still pay us $5.00 at the L.A.C.T. meter, but now we're going to have to take some of the pennies from that $5.00 and pay to get it from the flow station to the L.A.C.T. meter.

COMMISSIONER LERESCHE:

Which we'd have to do if we took in-value.

MR. BONESS:

If we took in-value, the producers would have paid us only $4.90, if it's a dime from the flow station to the L.A.C.T. meter, $4.90, so the state is in no different posture. The one potential difference -- one potential outcome which is covered by this contract is where if we take in-value, let's say we get the flow station -- let's say we get the L.A.C.T. meter price, the $5.00. But if we take in-kind, we also get the L.A.C.T. meter price, but we have to pay cleaning and dehydrating cost because as you know, there's a difference in the lease. One paragraph makes specific reference to cleaning and dehydrating costs and one doesn't. In that situation, in order to make the state whole and still have $5.00 in our pocket, we said that ALPETCO must reimburse the state for any costs incurred by reason of taking in-kind and make specific reference to cleaning and dehydrating cost, also with respect to other costs. So that ALPETCO would have to pay us the L.A.C.T. meter price, plus whatever we had to pay the producers, 30 cents cleaning and dehydrating

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costs, so ALPETCO's L.A.C.T. meter cost would go up to $5.30, even though the other 7/8's would continue to remain $5.00. And had we taken royalty in-value, we would have gotten $5.00. Under this contract, ALPETCO will then be paying us the L.A.C.T. meter $5.30.

MR. CHATTERTON:

They would be willing to pay us more than what they could buy it from one of the owner companies?

MR. BONESS:

That's right. That term is in there because there's no other way to make the state whole. They are willing to take the risk that there's not going to be a difference in in-value and in-kind.

MR. CHATTERTON:

Well you've just made me question their acumen as being a businessman right there.

MR. BONESS:

Well it's a legal question, more than a business question.

MR. CHATTERTON:

Well let me interrupt, if I may --

MR. BONESS:

Okay.

MR. CHATTERTON:

-- which I did. This hypothesis we had was if we lose the court case.

MR. BONESS:

I have problems, we could win some of it and lose some of it. That's when the problem comes up. Not like there's one question and the answer's yes or no. The question is how must they pay us when we are taking royalty in-value? How must they pay us when we're taking in-kind? What must we pay if we take in-kind? And the answer is, it may not be an absolutely identical situation. In one case they may pay us $5.00, to use your example. Let's say that the court says the proper place fo paying royalty in-value is at the L.A.C.T. meter. The L.A.C.T. meter value is $5.00. The court could also say when the state takes

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its royalty in-kind, the state must pay cleaning and dehydrating costs. That means we've won the lawsuit with respect to our contentions on royalty in-value but lost them with respect to our contentions for taking in-kind. We say we don't have to pay cleaning and dehydrating costs in either event, notwithstanding the provisions in the lease.

MR. CHATTERTON:

We have some unknowns then?

MR. BONESS:

That's right. There are some unknowns.

MR. CHATTERTON:

Then obviously my question is, how can we make a determination today as to what is in the best interests of the people of Alaska until we first know the outcome of the court costs--case?

COMMISSIONER LERESCHE:

We create an identity between what we would get at any time in the future if we'd never heard of ALPETCO and continued to take in-value and what we're going to get from them. That's why the price term is so complicated because it tracks future unknown events.

MR. BONESS:

There are no numbers in the price term -- in this contract. It adopts the concept that they'll pay us a sum of money equal to what we would have gotten had we continued to take royalty in-value. So we're not getting a premium as Chairman Miles has asked about.. But we're not going to get less money than if we just continued to take in-value. And it is as complicated as it is because there are so many unknowns at this date.

MR. CHATTERTON:

Okay, thank you, I think. Thank you Mr. Chairman.

UNIDENTIFIED SPEAKER:

He confused me.

COMMISSIONER LERESCHE:

He left out 2/3's of it.

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CHAIRMAN MILES:

Yes, I know, but that's easy to do. We're going to take a short 5 minute break to give these guys the chance to get a drink of water.

(Off Record)

(On Record)

CHAIRMAN MILES:

Questions.

Commissioner, the total project costs in the contract go back to January 1, '75. Would you give us the reason for that?

COMMISSIONER LERESCHE:

Not really. That's what ALPETCO wanted. The question arises -- it arose in my mind, what does this mean about the first benchmark, the promise to spend 2 million bucks before 6 months after the effective date. The fact is they've probably spent 1/2 million to a million already. That's fine. That's the conditions of the thing. The important benchmark, the first two, the two and three million dollar expenditure, was just a way to make them prove commitment continually and keep going. The key benchmark is 18 months. It involves 10 million bucks and financing for a billion five. So whether they spend a million two between now or between the time it's approved by the Legislature in six months or two full million, I think is insignificant.

CHAIRMAN MILES:

What would be included? What would be included back in October of 1975, perhaps somebody from ALPETCO could answer, if you don't know?

MR. HONIG:

My understanding is that the provision of the contract counts everything that we have spent since we began the effort of making a proposal to the state.

CHAIRMAN MILES:

Well it goes back to January 1 of 1975 and ALPETCO wasn't even formed, to my understanding, until last year.

MR. HONIG:

One of our major stockholders was Alaska Consolidated Shipping and they had incurred and did spend money in their same efforts, the same contract and my understanding is what they spent would be included in this amount. It's all for the same purpose.

CHAIRMAN MILES:

Might we get a copy of those expenditures?

MR. HONIG:

Yes, I'm sure.

COMMISSIONER LERESCHE:

They just want to write off Henry. (Laughter)

MR. HONIG:

We've already done that.

CHAIRMAN MILES:

Talking about the benchmarks, we have a number of extensions that are available and they total over four years if my addition is right. Doesn't that have the effect of substantially delaying the project after four years.

COMMISSIONER LERESCHE:

They're not cumulative, Bill. They're each measured from the effective date.

CHAIRMAN MILES: Well if each extension was granted, each benchmark, it could be cumulative?

COMMISSIONER LERESCHE:

No. Okay, you've got, let's say, the 18 month benchmark can be delayed six months and that's measured from the effective date. So say they have two years, if it's necessary to meet the 18 month benchmark. The 24 month benchmark can also be delayed six months. But 24 months is measured from the effective date, again.

CHAIRMAN MILES:

From the effective date, that (indisc.--sumultaneous speech)

AGO 545579

COMMISSIONER LERESCHE:

Yeah.

CHAIRMAN MILES:

-- I just misread that. Any questions? I have plenty but --. Senate?

SENATOR SUMNER:

I think I can sort of summarize, the fact that I don't have any questions doesn't mean that at some future date I won't, it just merely means that at this time I haven't had an opportunity to review the contract in some detail and to attempt to track down some of the questions that I will have by both staff and consultants' support and at that time come back with some questions, but that's my posture at this time.

CHAIRMAN MILES:

Okay, well we might as well call it a day.

MR. BONESS:

Okay, thank you very much Mr. Chairman.

COMMISSIONER LERESCHE:

Thank you, Mr. Chairman.

***** End of Proceeding *****

AGO 545580

Lipton

3/15/78

Observations:

① advantages to Alaska

Basis for ind. establishment / development.

③ Prospects of Success

Disposition of chem prod on W. C is a reasonable assumption - a potential mkt

Foreign Mkt - the most elusive and difficult to predict - the areas from which it can be supplied "look well as much more attractive than Alaska"

Incentives for investments in the Middle East -

- Transp. disadvantage
- Capital "
- Assured supply

} not because of

political thrust to develop an ind. profile for reasons difficult to platform - Impt psychological urge to assume a pivotal political role - not just look

AGO 545581 +

the role but act; it will
Export rights get served out of
exportable supply; ie., Middle
East

(2) Disks to Alaska
If project can come to fruition,
but (3) becomes a reality then
what?

Interim Period
Due dates - if they cannot
be met even if ARPETCO performs
sincerely, will the State really
cut them off or will they afford
them the oppt to make up!?
No. Then, what are the
risks for the interim being
tied to a contract.

Profitability
Does the group have the financial
wherewithal to stick it out for instance
5 yrs? Or will the State be forced
to lower the price

Prospect is leading the State to
got further and further sucked
in, assuming an equity position
Alaska does not look too much by

AGO 545582

defering the decision.

Income tax based on in-state
→ Multi national
formula. It would not generate
much in income taxes

Comm → "First" sale should be in Alaska
this way would have a leg
up for tax purposes!!

Questions:

Chatterton: Risk - getting Cass - Yes!
(the legislature)
Should we take a risk
with the people's money
or oil - Yes!

Parr: Main benefit - Breakthrough?
Yes!
What are the obsolete plants
in Japan with a modern
plants - ? old plants an advantage
rather than liability
in many cases.

AGO 545583

→ To the AK disadvantage outweighed by assured supply? Questionable!
We would be fighting the export battle, which is now being increasingly determined (price) by Middle East

Miles: Future Reserves?
another wish! May be for more attractive in the mid 1980s — assured supply vs. "Alaska disadvantage"!

Pricing: We are being asked to make the same commitment as far as timing is concerned as is ALPETCO
If the State thinks PB is it, maybe the time is ripe to make that commitment now before too much is gone. If the State feels more sure in future reserves maybe we can wait in committing ourselves.

AGO 545584

And for how long?

Hackney: Would the sky fall in if we waited?
The sky will not fall by delaying the contract. Urgency is absent availability now which will decline.
A yr or two will not be tragic; but we are turning our back on something that came to us in good faith!

Patterson: If Option existed where would you locate project? at Valdez or W.C. of the US?
W.C. absolutely!

Later commitment better than earlier commitment!

Miles: Saudis willing to offer more than 4K!
They will offer over and above. (ISOM + (SOM)
ISOM to process - SOM free of all strings).

AGO 545585

Stability of supply bases is attractiveness. Contractors Typings!

Part 5 What are the risks ?

Risks: Contract will collapse, most likely went.
Venture after venture fails what is our credibility
- During time frame in contract - not too bad
- after initiation first 5 yr will be difficult, and state will ~~be~~ feel obligated to do something not required by contract.
State will not allow it to flounder because of a lack of cash flow.

Royalty crude contract should not be conditioned on what State wants to do with it or

AGO 545586

Wednesday

4. Mr Leon Lipton and Dick Kelgore

Mr Lipton made his comments in the form of observations.

1. advantages to Alaska
   - successful implementation of contract serves as a basis for industrial development
2. Prospects of Success
   - The ~~prospects of~~ disposition of chemical products on the West coast is a reasonable assumption – the potential market exists
   - However, the foreign market is most difficult to predict. Other areas from which petrochemicals can be supplied "look ever so much more attractive than Alaska."

The incentives for investment ~~a~~ in the Middle East, which ~~are~~ are no better – maybe

AGO 545587

(stable supply)
worse than Alaska is that
in addition to what ~~we~~ Alaska ~~are~~ is
offering, ~~they~~ the Saudis
are offering certain volumes
of crude over and above
those committed to the development
of a petrochemical industry
in their country with no
strings attached. Lipton is
thus in disagreement with
Joe Tydings (

AGO 545588

Alaska State Legislature

POUCH Y, STATE CAPITOL
JUNEAU, ALASKA 99811
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TRANSCRIPT OF TESTIMONY OF

MILTON LIPTON

March 15, 1978

BEFORE THE SPECIAL COMMITTEE ON ROYALTY OIL AND GAS

Committee:

Senators:	Representatives:
Chairman Mike Colletta	Chairman Bill Miles
Pat Rodey	Chat Chatterton
Bill Sumner	Joe McKinnon
John Sackett	Charlie Parr
Kay Poland	Al Osterback

CHAIRMAN MILES:

I'll call the committee to order. Senator Hackney, would you care to join us? Senator Sackett? We'd be more than pleased to have you. We have with us tonight Mr. Milton Lipton. He's going to give us some of his observations on the contract. He's certainly well known to all of us. So with that, Mr. Lipton, please --.

MR. LIPTON:

I'd like to ask Mr. Kildrum (ph), my ass~~essor~~ociate, to join me. I don't mind volunteering observations to the committee but if the questions get too difficult, I'm going to throw them at Dick.

Your committee's obviously been close to this issue for a long time, a lot closer than we have been and when we met the latter part of January, you asked me if I would comment on the subject of the oil royalty contract. At that time it was still in the competitive stage and I offered some very general observations on what I saw were the critical considerations involved. I will not repeat myself to you.

UNIDENTIFIED SPEAKER:

Mr. Lipton, I'm having a little bit of trouble hearing in the

back.

MR. LIPTON:

Well I'd be glad to address myself to the ALPETCO group, but that would mean turning my back on the committee. Does this do it, does this help?

UNIDENTIFIED SPEAKER:

No, I think that's just a tape recorder. You have to move forward.

CHAIRMAN MILES:

You just come on up.

MR. LIPTON:

I'll try to talk louder, not better but louder. Really, we have put together, I think, three observations about the contract that is now in front of you. And I think one footnote to the three observations, and I'll try not to be long-winded about these, and then place myself at your mercy for whatever questions you would like to ask.

I start with the first observation which is that if the royalty contract placed before you is approved by the legislature and if it comes to fruition, there are some very definite advantages for Alaska. And I see these as especially significant in the light of the fact that when the issue or the subject or the possibility of the sale of royalty oil as the basis for some kind of industrial establishment was first (indisc. - cough). The companies that are most likely to be parties of the first part, rather they are oil companies or chemical companies, were extremely reluctant to come forward with positive commitments. We know this because among our clients were companies that really discussed the prospect and many of them looked at it, some seriously, some less than seriously. But in light of the fact that the companies who might have had the best controlled markets for the disposal of either energy products or chemical products were themselves reluctant or didn't visualize the prospects as particularly conducive or were reluctant to make the investment, that in consideration of all of this, it stands as significant that there is a contract before you with a group who if they can perform and if it comes to fruition would contribute something that otherwise you have been unable thus far to get. And that in itself I consider to be a plus for what has been the process of investigation, discussion and negotiation up to date. That's my first observation.

I skip to my third observation, and that has to do with how we see the prospects for success. Now I speak of this, not in terms of the probability, it is no part of our role to tell you what the chances are of this thing coming to fruition, but I think it is important to evaluate again what the difficulties and what the problems are. Particularly, because in all of the discussion and in all of the representation there has been a great deal of possibly and probably, and sometimes not coming to what we think are the realities of the project, or any project faces.

The disposition of chemical products on the West Coast is, I think, a reasonable possibility; that is to say there is a great market at the present time which is supplied by indirection out of capacity in the Gulf area. The market is undoubtedly growing. One can argue about rates of growth in the United States or in world markets, and I put that aside. I don't think this is a numbers game. But there is a potential market on the West Coast.

The difficulty, of course, is that the companies who are in most direct control of the market are not the ones who are participating here. It becomes a matter of whether one can establish the relationship which makes it possible to do.

I think that the foreign market, which is discussed, which is essentially the western perimeter of the Pacific, is probably the most elusive and the most difficult one. It's not because there isn't going to be a growth in chemical demand in Japan, Southeast Asia, and the Pacific basin as a whole; there will be a considerable increase in demand. But the areas from which that chemical demand can be supplied looks to be ever so much more attractive than out of Alaska. I'll give you our quick thinking on this.

The expansion of chemical capacity to serve the markets by Japanese chemical companies is undoubted. It is going to happen. The question is from where. For a lot of reasons we think that the major expansion of chemical capacity by Japanese companies will not be in Japan. It will be outside of Japan. There are limitations on what can be done in Japan for a lot of reasons, not the least of which has to do with siting problems, has to do with environmental problems that are very, very real. But it means that if the Japanese chemical companies are going to export capacity, they will export capacity to those areas where it is most strategic for them to do so. And that means either exporting the capacities, say, into Southeastern Asia, the whole range of areas all the way from Taiwan, through Singapore, potentially through Indonesia, where in a sense they are in the direct line of the main flow of feedstocks from the Persian Gulf area, the Arabian Gulf area, to their markets. Or, they will participate directly, or indirectly, in the expansion of

petro-chemical capacity in the Middle East itself.

I think there's some misunderstanding about what the incentives are for investment in the Middle East. It's true that capital costs are relatively high there, but the decisions of companies whether or not they put their capacity into the Middle East, where capital costs are high and where transportation costs to market for petro-chemicals are high, better moving the crude oil from the Middle East to Southeast Asia, the naphtha that comes with the crude oil, you process the naphtha. Given the transportation disadvantages and given the capital disadvantages, the reason that the companies are considering going in there is not just that they get an assured supply of petro-chemical feed stocks (ph), which is the argument in behalf of the Alaskan facility, if in the future period of time there is question about the continuous availablity of feed stocks (ph), shouldn't you go where it is available - Alaska or Middle East? It is more than that. It's that there is a political thrust on the part of Middle East governments - Iran, Saudi Arabia, especially - to develop an industrial profile for reasons that are difficult to follow. I don't know the reasons for it, but to develop an industrial profile which somehow is a reflection, also, of their importance in the world at large. They aren't important in the world, because Saudi Arabia is going to be pivotal to the supply of oil and gas for the world. Why an industrial profile that reflects it? Certainly not to create unemployment. They don't want unemployment of Arabs, and they have great concern about the importation of foreign labor that might work there. But I think there's an important psychological urge that, if Saudi Arabia is to occupy as pivotal an economical and political role in the world as they now believe they can, and as the world outside tells them they must, that somehow they ought to look the role as well as play the role, and this involves some kind of an industrial profile which fits in with everything else.

Now, to do that, they have not only to offer the feed stock (ph) for the petro-chemical plants, and as a considerable negotiation, what price ethylene to an ethylene operation, and how do you handle financing, more important than that, and this is what brings in the Shells and the Mobils and the Dows and, in due course, the Japanese, that they're prepared to offer, in addition to the assured feed stock (ph) near the petrochemical plant, a collateral supply of crude oil for export purposes. The investment in the petrochemical facility will not only directly or indirectly overcome the competitive disadvantages, which you have in Alaska and which they have also (high capital cost, high transportation cost), they can put in the at a very low price if they will, they can offer low-cost capital advances, but there is a hundred to a hundred and fifty thousand barrels a day of crude oil, which in the late 1980's will be available to the company that is willing to make the petrochemical or the refining investment. And this is what is bringing the facilities into it. And this means you will have, not as quickly as we had anticipated had been brooded about,

and not on the scale that originally went into the Saudi-Arab investment program. And, in view of the surpluses, neither the companies nor Saudi Arabia are that anxious to push the thing along, which is one of the reasons the negotiations proceed.

But there will be, in due course, a reasonable expansion of petrochemical facility in the Arabian Gulf and in the Persian Gulf, because the Shah will have at least one major facility. This expansion, which willy-nilly is going to have to move to world markets and which faces special competitive disadvantages in the European market, or the U. S. market, transportation problems, no quick mode of transportation, the kind of ocean-going carriers that are lowest cost probably couldn't go through the Suez Canal - what goes through the Suez Canal is higher cost transportation - plus protection in Europe by the Common Market for their own chemical industry, so worthily (ph) you are looking at the western rim of the Pacific, which is precisely what Alaska would hope to get to augment whatever the potential is in California. And if the export of processing capacity by the Japanese chemical industry to Southeast Asia, coupled with the competitive supplies out of the Persian Gulf are put together, what it means, in effect, is that the present capacity in Japan, which is both for domestic and export markets, becomes increasingly available for domestic markets, because the export markets get served out of the export capacity to other areas.

This is why we feel that it is extremely difficult to visualize the (indisc.) of commitment of Japanese, because given the proper terms and conditions, there may be certain commitments. But the way in which the competitive environment operates in '85 and '87 and in '89 when an Alaskan facility comes on (indisc.) and they may have to supply parts at not stipulated prices, but at what are called competitive prices, I think both volume and price-realizations are questionable. The point of what I'm saying here is not that I'm trying to tell you the odds of the project coming to fruition, that's not my point. I think that you've got negotiated, both by the State and by the ALPETCO group, as an imaginative combination of factors into a contract as you could get, particularly in view of the fact that nobody else was forthcoming. What I'm concerned about is my point two, which I now come back to. Namely, what are the risks for Alaska? Because, if the project can be put to fruition, but if the economics should turn out as complicated and as difficult as we think they will, then this raises the whole question of what the risk is for Alaska. So I come back to this, which is the in-between thing.

Yes, it's a heroic effort on both parties' parts, and I think a very carefully drawn contract.

Number three - we think there are problems, And, if we are right about the problems, but meanwhile the contract is moving forward, what are the risks for the State of Alaska?

I suppose that in the interim period. they are pretty much minimized by the terms of the contract. There are due dates and performance commitments right down the line. So how can Alaska really lose on it? For example, the ALPETCO group, which for reasons that I can only partly interpret, would like to have prior access to the crude oil before the facility is completed. Obviously, if they have that option, and in eighteen months they have met their commitments, they would only exercise their option for the crude oil if it turns out to be profitable for them to do so.

But, how much protection does Alaska have in this interim period? Well, the due dates are very clearly specified. There are certain allowances to the Commissioner six months at various dates (indisc.). But, you know, I rather suspect that if this group works as hard as they obviously intend to, that if there comes a due date and there is evidence of sincere effort, will Alaska at that time say, "Cut them off because they haven't met their commitment," or will you be more inclined to say, "Well, look, all the evidence of effort is there - one is on the verge, shouldn't we go?" Which means one may extend all of these due dates somewhat beyond the contractual terms, which may not be bad. The only question then is, for how long a period of time has Alaska, in a sense, given the first option for all proposals to this selected group and, during this interim period which may be assured is eighteen months, but may be as long as two years or two-and-a-half years, which in effect blocks out any alternative proposal. I have no idea if alternative proposals come in, and I don't weigh this very heavily. But in my own mind, as I visualize the progression through which one goes, one has to ask realistically whether a due date at which point performance has been completed or the contract is voided is really realistic. If in fact this group will perform, as I expect they will; that is, with diligent effort and always with the expectation that things will be coming through. But more importantly, your contract is a contract contingent upon a whole series of performance. The ALPETCO group must also look for the contracts which they need, both for off-take of products and for the commitment of funds, which, in a sense, are contingent,too. That is to say, as long as things continue to look prospective, one goes along.

What is a contract for the off-take of products? Specified products, specified quantity into a certain market at what? At a guaranteed price? Never. It's also got to be at a price which allows the buyer to be competitive in his own markets. Call it what you will - world market prices, competitive prices, whatever it is. And so long as things are running this course,

and in every stage of the game there may very well be a feasibility study, one goes along; which means the lenders do, the ALPETCC people do, and the buyers do. But, if, finally, this facility is built and if you have five difficult years in which the lenders can be satisfied but the profitability of the refining bill really isn't there, that is to say, there would have to be capital infusions to keep it running, does the group have the financial capabilities to weather five or six years of difficulty beyond which the project may work out fairly well? Maybe not, but it could very well be. Or, does it become the responsibility of Alaska, in a sense, to provide them with essential support in the expectation that things will be better. The light at the end of the tunnel and the way you do it is you turn the equation around. The equation today is that the feed stock (ph) costs are fixed. They'll make a profit by selling competitively. You may have to turn it around that the selling price of the products is determined, and in order for the thing to survive, you have to adjust the feed stock (ph) costs to what the market looks like. This, I think, is the risk of Alaska. I'm not trying to pre-judge it. This is not a forecast, but I think that if you look at the combination of realities which the group faces, it is less disadvantageous for Alaska, but the realities stop the project, in a sense, and made a good pass at a Royalty crude contract but it hasn't worked out. Then that always the prospect is leading you one step further and then Alaska gets in the position where it, willy-nilly, is party to the equity position of the project because it will be very, very difficult for a billion, a billion-and-a-half, two billion dollar project in which the state has a vital interest to suffer financial disabilities and maybe threathen some future viability, which is only two years down the road, a few years down the road, or four years down the road. This, I think, is what you must assess.

And, as I said last time, and I simply quickly summarize. In the state of the circumstances, if you the Legislators have significant doubts about the balance between the benefit to Alaska and the risk, I don't think Alaska loses too much by deferring the decision. This, of course, is contingent upon whether you think royalty oil will be available in the future, whether you think one or two years or three years of draw-down of reserves is going to prejudice your ability later on. But the way in which one sees the future suggests that the perception of all parties as to the value of assured access may improve over time. And, there's no question about it, that the success of this project depends upon the participation of other participants, and the stronger the other participants are, the more closely entwined they are, the more they appear as a party of the first part, the more chances there are for success.

What you are wrestling with here is outside financing, outside marketing, all contingent upon the performance of other parties

and with an imaginative and an agressive effort by the ALPETCO group, but with limited capabilities on their own, as we see it.

Now, just one footnote to all of this, and then I give you your crack at me. I say this because we have just come this visit and the previous January visit and last year and the year before with long discussions about the adequacy or inadequacy of the state's income tax. In reaching out at the income generated by operations here in Alaska, and there are bills to change the income tax - I have no idea where they are going - but let's assume now that the income tax remains as it is, which means that for any multi-state corporation the income which you can tax here in Alaska is not measured by the profits in Alaska but is measured by the allocation of their overall profits earnings allocated by formula through Alaska. And, as you know from long dicussions, the big deficiency in the formula is that the sales factor gives you virtually nothing. You produce a lot of oil, or you might refine a lot of oil, or refine a lot of petrochemicals, but very little of it is sold in Alaska. So the proportion of a corporation's, of a multi-state corporation's total sales, which are sold in Alaska and become very small. So little of the income is allocated here.

I know very little about the internal structure of ALPETCO now, let alone what it may be by the time the project comes to fruition. But to my mind it is quite conceivable that it will be engaged besides petrochemical operations in Alaska with at least transportation and perhaps some satellite projects. They would like to get as much of the down-stream investment up here in Alaska, but they may be involved in California. I don't know.

What I'm suggesting is you might want to consider that if the state feels positively inclined that you might at least consider that part of the arrangement between the state and the group shall be that the first sale of products out of the facility shall be made in Alaska. It doesn't mean it stays in Alaska, but it can very well be exported. But if the first sale, whether it's to a trading company or to whoever, takes place in Alaska so that one comes to reckon what the earnings are, subject to tax, apportionments, or anything else, that at least you have under your present income tax statute and under your present allocation formula, at least you have a leg-up that there is a reasonable proportion of the product produced in Alaska is also sold in Alaska so that for tax purposes at least it get allocated back here. Which means you're not increasing the tax burden on it, but what you're saying is you have at least a chance to identify and reach out and tax it. This is a footnote, and it comes up only because this whole issue of the income tax has been so much in the fore for such a long time and we've been pivotal to that discussion. So I think you may want to consider that.

CHAIRMAN MILES:

Thank you very much. It's always a pleasure to have you come before us. Are there any questions from the committee?

MR. CHATTERTON:

Yes. I'll strike out first, Mr. Chairman, if I may.

Unequivocably, Mr. Lipton, you feel that a sale of our one-eighth royalty oil, that there is a risk attached to it. A risk that we might end up getting less for that one-eighth than if we took it back.

MR. LIPTON:

There is a risk. There surely is a risk.

MR. CHATTERTON:

I'm curious if you are somewhat acquainted with the State of Alaska's Constitution. Over the years you've been coming up here, it more less states that the resources of the state belong to the people. I'm wondering if you would care to make a comment as to whether or not we, as a Legislative body, have the moral or even consitutional right to take a risk with the peoples' money, or would the people go after it.

MR. LIPTON:

Well, you put your questions very, very directly, and it's awfully hard for me to equivocate when you put them that way, and I can't. Yes, I think you have a right to take the risk because you always take the risk. You take the risk in every kind of a lease sale. You take a risk when you select the bidding variable for a lease sale. You take a risk when you decide on how you choose among tax alternatives. These are all risks. I guess, unequivocably, I've got to say yes you have a right to take a risk on this, also.

MR. CHATTERTON:

Okay, fine. Fine. Thank you.

MR. PARR:

Mr. Lipton, if I understood you correctly, I think what you saw as the main advantage of this whole contract operation is that you got a breakthrough. You finally find someone who is willing to stick his neck out and go for a petrochemical complex in the West.

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MR. LIPTON:

Gee, you put it so simply, and I was so complicated. Yes.

MR. PARR:

Okay.

MR. LIPTON:

That's it.

MR. PARR:

The second thing. . . I'd like to paraphrase what you said to make sure I've understood it all. There's going to be growth in the Japanese petrochemical industry. Most of it is going to be exported capital growth. They're going to build the plants either in Southeast Asia or in the East. And those . . .

MR. LIPTON:

For a specific market. For a specific market.

MR. PARR:

And those plants are going to take care of the export business. The plants that have been formed that are rather old-fashioned, using naphtha which are now in Japan itself will be servicing their domestic market.

MR. LIPTON:

Increasingly, yes.

MR. PARR:

Yes. What is the general status of the ability of those plants remaining in Japan? Those domestic plants we have been told, at least, are rather old-fashioned, to compete with a modern plant now coming on the line; but coming on line in 1983? Given their advantage of being on the spot.

MR. LIPTON:

Well, look, it depends upon what the ingredient of the competition is. Uh, in many respects a depreciated plant has a tremendous competitive advantage over a new plant if you're talking about relative costs of production, relative costs of processing. It depends how you calculate the costs. If you're saying, if you're looking just at operating costs, they may not be that competitive. But if you're looking at the whole complex of costs that go in with a great deal of the capital investment written off, and

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you're looking only at the incremental cost of operation, they can compete. Hell, some of our oldest plants in the U. S. Gulf are competing in world markets today. And, so

MR. PARR:

You mean, in that case, that the advantage of having depreciated their plants already outweighs their technological backwardness. Is that what you are saying?

MR. LIPTON:

I'm not even sure how technologically backward they are. You know, it's an interesting question as to which technology is going to be the most competitive. Because technology is also a function of the feedstock that you use. Now, you know the new generation of ethylene plants, which are coming on stream in the U. S. Gulf and which is proposed here, are gas-oil plants which, basically, have a somewhat higher capital investment required relative to a somewhat different mix. But it's not at all clear that the direction in which the world petrochemical capacity is moving is going to move more and more towards the heavier feedstocks rather than the lighter feedstocks. Because if you go towards the Persian Gulf or the Arabian Gulf, you're talking about a fantastic availability of ethane, which is lighter material. If you look . . . I don't want to get more complicated than is necessary, but, if you look at the projects for the development of natural gas and natural. . . LPG liquids. Now there's talk about can you have an LPG base petrochemical operation here in Alaska? It's one of the things that's been considered. The amount of LPGs which are coming out of the Arabian Gulf between now and the early 1980's firm, and prospectively by '85, '87, and '88 suggests that propane, which has never been the basis for petrochemical processing in the whole Eastern hemisphere, although there has been to an extent in the U. S. Gulf, may become a competitive factor for petrochemical processing.

So, it's very difficult. I really don't want to substitute my judgment for somebody elses. All I see are so many uncertainties in the picture. But it's very, very hard to say with the kind of confidence that I would like to say that if only you have an assured source of feedstock here in Alaska, that outweighs your competitive disadvantages. And your competitive disadvantages are very clear. You heard . . . I don't even want to repeat it. . . you've heard this so much. The question is, does the assured availability outweight the competitive disadvantage. It may for the Western hemisphere, and you may even get Japanese participation here for world markets, not on the Pacific rim - the Western Pacific rim, but for the world markets in the Western hemisphere. The Japanese are very active here.

They want to make an investment, which would be fine because they like to diversify their investment, and the Western hemisphere looks very good to them. But that's not the marketing output over there. And any way you look at it, you're moving against the mainstream of the flow of energy commodities and the buildup of energy values. You're pricing . . .

MR. PARR:

I'm sorry, I don't follow you.

MR. LIPTON:

The center of pricing for energy commodities and derivatives will be increasingly, it almost is today, but not quite, increasingly out of the Arabian Gulf. And as you move eastward, it builds up in cost. True. But, if you're going to move against that, it builds up in cost more and more as it comes toward the U. S. East Coast. And if you have crude oil out of Saudi Arabia, or whatever else, or the naphtha which is derived from the crude oil, or the gas oil which is derived from it, it all builds up in cost and, therefore, in value as you reach the U. S. West Coast. Well, you have a better competitive value in the U. S. West Coast, but if you start moving with transportation costs against that flow, you're moving further and further in the direction in lower cost feedstock (indisc. - cough) cost alternative feedstocks. Whether they are naphtha or whether they are gas oil or whether they are ethane in the Persian Gulf area, (indisc.) the Arabian Gulf itself, or whether they are LPGs.

MR. PARR:

You say moving against that flow you are talking about, in other words, trying to supply markets which are nearer to the Mid East. .

MR. LIPTON:

Nearer to the place where the price originates. That's right.

MR. PARR:

Now I'm with you. I think I'd like to look at this a little further.

CHAIRMAN MILES:

Mr. Lipton, in there, speaking directly to the contract, as you are aware the contract does commit some future unknown reserves. In light of the risks that we understand (indisc.) ALPETCO and the State of Alaska will be taking should it go ahead with the project, can you comment on the (indisc. - cough) that the State might have in committing those unknown reserves, the non-Prudhoe reserves?

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MR. LIPTON:

Insofar as there is a question whether you will have adequate royalty oil out of Prudhoe over the duration of this contract, whether it's this contract or any other contract, if, in fact, it's the assured availability which offsets the known disadvantages, then nothing's going to fly unless you're prepared to commit the hundred of a hundred and twenty-five of a hundred and fifty. Which means also the right of first refusal over any deficiency out of the royalty oil from Prudhoe out of other royalty oil anywhere else in the state. That is, whether it's this particular project, or whether you say no to this, and Dow Chemical comes back three years from now. If you're going to offset competitive disadvantages by assured availability, you've got to assure availability.

Is there a risk in this? Sure, this is another one of the risks. And the risk is that, in effect, you are committing this oil to a particular project under specified contractual price arrangements, which may by 1988 or 1989, 1990, or 1992 look to be far more attractive than other alternative in uses. It is difficult to say. And again, all . . . I think if you want this kind of a project, whether it's this group or another group, you're going to have to give assurance of supply. It's a risk you take. I don't know how high I would count that risk. I think, in many respects, the contract is as carefully worded as it can be to minimize the State's risk. I mean,you're not going to get any bargains on the royalty oil, although in the light of unknown circumstances it may be that they will still be able to get it at a price for their facility, which is less than what the State might otherwise later on may have been able to negotiate.

CHAIRMAN MILES:

Let's talk about pricing for just a bit. When you've come down and talked to us before, you have explained your theory about the, and I can remember you doing it, . . the surpluses like this now, when it's going to be like this a little bit later on, and it was the availability versus the price, and you really didn't, we didn't have a contract before us. Can you comment on that theory insofar as this contract is concerned?

MR. LIPTON:

Oh, I still think it's the case. This group. . . again, I think imaginatively has foreseen what the world is going to look like in '85, '89, and '90, '95. Which means they are presuming they can take your royalty oil today, within twenty-four hours construct a facility, and sell the products in a world in which petrochemical capacity is way at surplus. So, therefore, seeing the time when, one, there will be less surplus capacity in the

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chemical industry, a greater demand from products from new facilities at a time when the new facility, which has assured access, has got a leg up over a new facility that doesn't have assured access. So, they're willing to take their chances on the price equation because they think that this is . . . . So, they are looking very, very far ahead.

I guess what I said to you last time that the way in which corporations react to this future, and virtually everybody sees the future the same way. They have different years that they put onto it. The C.I.A. says a catastrophe by 1982- - - we're all going to run short of oil. The O.E.C.D. says well, by 1988 - '89 it's going to be tight, but there's going to be enough oil left. Everybody sees the due date as somewhat different, but everybody sees the probability of a tighter supply situation in the world of oil than (indisc.) is today even if there aren't acute shortages.

Now, when investment decisions are made with a sense of urgency, or when prices start getting bid up, doesn't depend upon the shortage being there. It depends upon how soon companies begin to see the shortage within there planning periods. If you've got a five-year planning period, and you see the shortage coming up within five years, well, that's at hand. So, what we're talking about is not shortages in the early 1980's but when companies will have to make investment decisions and begin to say, we'd better start worrying about what our position is going to be within the period of time that we make capital commitments for capacity. And there are very few that are doing it today. The ALPETCO group is saying that, essentially. I believe so. What they are saying is, we're not building for today's chemical market, we're building for tomorrow's chemical market. And, if we've got this thing timed right, we come on-stream at the right time. And they are saying it.

But, you know, none of us know when year "x" is going to come, and you are being asked to make a decision on the same basis as the ALPETCO group has made their decision. That is to say, make your commitments now well in anticipation for a facility which will come on-stream when '83, '84, '85, at the best, and will run for about twenty-seven years more. Than whether that's the best time to make that decision, it's hard to say. And, if you're convinced that you have a limited amount of royalty oil with which you would like to achieve a purpose, and if you don't do it within this year, or at least a couple of years, you may not have the same oil to bargain with. Then, perhaps the time is now.

CHAIRMAN MILES:

What you're saying is that we are at a very similar investment decision crossroads that ALPETCO or anybody else is.

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MR. LIPTON:

Absolutely.

CHAIRMAN MILES:

And we have to make a decision if the time is right for us to invest.

MR. LIPTON:

Sure. And, truly, if you want a facility which has to depend upon assured availability, and you think that all you've got is 12 1/2 percent of something under ten billion dollars at Prudhoe, and you've got to strike your bargain with that before too much of that runs out, then you don't have that much time. If you think that you've got a future here in Alaska, and it's not just Prudhoe Bay, but a lot of other things coming on, then the cost of waiting is perhaps not that great.

MR. OSTERBACK:

Is there anything else they could do with this crude oil? Would it be feasible for putting in a plant for rope and (indisc.)?

MR. LIPTON:

For what? I'm sorry.

MR. OSTERBACK:

For rope. You know, like nylon rope, poly-rope, web . . . Has anybody ever talked about that? The price has been doubling on that.

MR. LIPTON:

Not that I'm aware of, but if you have an aromatics plant, you've got the basis of nylon. Now how far you go. . . You know what the problem in Alaska is? That the closer. . . you have a very limited market here, a very limited market, so the more you go into finished products, you know. . . . To satisfy the Alaskan market is really the best thing that could happen to Alaska. Whether it's nylon rope or garbage bags, or almost anything which is petrochemical-based. This becomes a tremendous advantage for Alaska, because otherwise you ship out and you ship back and forth, but there is a real problem involved - how far you can push the downstream processing into finished products.

MR. OSTERBACK:

I'm not talking about shipping, but most of our rope now comes from Japan, Norway, Sweden, and that's a hell of a lot further than Alaska, if you're talking about shipping down to Washington, Oregon, and California. It's a lot closer.

I mean, I was just asking if that would be feasible to put these plants up.

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MR. LIPTON:

I don't know. From the standpoint of any group itself insofar as they can satisfy the Japanese market, if they can satisfy the Alaskan market, which otherwise is served from Japan, it's all to their advantage. It's all to their. . . The question comes down to scale and how they are going to put it all together. I really don't know.

MR. OSTERBACK:

Thank you, Mr. Chairman.

SENATOR HACKNEY:

Mr. Lipton, the prospect of not having to make a decision is always something that is dear to a Legislator's heart. Did I understand you to say that the sky would not fall if we were not to accept this contract and were to wait say, a year, two years? And, if we were to wait, how long should we wait?

MR. LIPTON:

With a certain amount of confidence, I will answer, the sky will not fall. Now that I answer the other part of your question, I have more difficulty. But, really, what is now being proposed? The sense of urgency is because of the availability of the oil. If you don't commit it, then whoever wants to put together a project has more and more difficulty of telling his customers and his financiers that the one thing I've got that other people don't have is the short availability. 'Cause the further you postpone it, the less assurance there is of availability, unless, come '79 and an open-lease sale and some successful drilling, and then everything gets turned all around.

But, I would think that a year or two is not going to be tragic for Alaska, except that, in a sense, what you're saying is we are turning our back on what has come to us in good faith, because we are hoping for something more. I would. . . This has to do with the psychological. But, the companies who might otherwise be involved with the ALPETCO group are not going to disappear in a year or two. They are still going to be there for ALPETCO or anybody else, or maybe come in as a party of the first part. I don't know, and I certainly don't hold this out as something of great promise.

I really don't think that . . . It's one set of uncertains against the other. There are risks in this; there are uncertainties if you say no. At least what you've got here is certainly a promise of sincere and major effort. I think that that's about the best that I could. . . There are uncertainties all over the place for them, for the State of Alaska.

CHAIRMAN MILES:

Can I follow up on that, Senator Hackney, if I may?

If the risks are there, I suspect similar risks will be there in a year or two. But, don't we come down to a situation where the oil becomes more valuable to the State of Alaska and, therefore, to any potential purchasers in a year or in two years?

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MR. LIPTON:

Well, I think that out of a combination of world developments and U. S. policy, your oil will become more valuable. It will become more valuable as royalty oil and it will become more valuable for whatever purpose. The only question is whether you have dissipated a sufficient quantity of the Prudhoe Bay reserves and what you have left is royalty oil, looks to be less and less sufficient as the basis for a short availability. One can't turn his back on that. If it's assured availability that's going to overcome competitive disadvantages, then the longer you hold out the less you have to offer as assured advailability and the more it becomes speculative. The next time around, and the third time around, and the fourth time around you would have to offer an option on what comes up.

The other things come through relatively quickly, you're in great shape. Absolutely in great shape. I would say that if there were another major discovery in Alaska, so that you see your future further down the road than you do today, then you will have lost nothing. Except you will have lost the effort of a very determined group that are pushing like all hell, and that doesn't (indisc.).

MR. CHATTERTON:

Thank you, Mr. Chairman.

Mr. Lipton, I've been trying to figure out how to get to this question. I think I finally may have. If you were a party, the buyer party, to the contract as you have seen and probably understand, and everything in that contract remained constant, but gave you one option not in that contract now. . . say we could give you this option. . . to locate this complex that you are going to build in Valdez or someplace on the West Coast of the contiguous "forty-eight", what would be your choice?

MR. LIPTON:

The West Coast, beyond any doubt. If you had the same assured access to Alaska's royalty crude for a project on the West Coast, I don't think anybody would consider Alaska.

It's not a natural location for a petrochemical facility, anymore than Puerto Rico is.

MR. CHATTERTON:

If I heard the testimony on the last couple of days correctly and the answers to questions correctly, I think that the solitary, single big apple is the (indisc.) one that you mentioned, and I think that ALPETCO fully recognizes, and this is the long-term twenty-seven-year (indisc. - cough).

MR. LIPTON:

Of course, of course. Surely, surely.

MR. CHATTERTON:

And if we could keep the same supply, if we could lock it up right, or we could replenish it from new discoveries, would not a person be willing to make even greater sacrifices as the buyer may possibly be willing to make greater sacrifices in years from now than you are today, with the same guarantee....

MR. LIPTON:

Well, I think that, if you are right in our perception of the future, the closer we come to the time when the buyer sees close at hand the tightness, the more valuable assured access becomes. Yes. In the same sense that the parties that are negotiating in the Middle East today, on both sides of the fence, are rather prepared to drag the thing out and let it go, so, instead of coming onstream in 1981, it comes onstream in 1984 or 1986. There is no sense of urgency if they can keep negotiating, but get the thing going at a time when it's closer to when everything looks to be relatively more assured than at the present time. I think that's right.

MR. CHATTERTON:

Anyone in our case, with the contract we have, anything we can do to, and I can't remember the terms of the contract so this may be in order, but, if it's possible, why we would....you as the (indisc.) would certainly be interested in trying to extend so far as possible into the future the date that triggers off the twenty-seven-year period. And it may be the contract starts....

MR. LIPTON:

I'm talking now as a buyer, not as an investor. But it depends upon the buyer's circumstances. He has his own conception of when he needs products for further processing for integration into his markets. And, if he foresees that he is going to need new capacity either by construction or by purchase for 1983, he would just as soon start a contract in 1983. But given the way the surpluses are going, if you want to generalize, I would say, yes, you're better off later down than line than earlier.

MR. CHATTERTON:

Thank you. Thank you, Mr. Chairman.

MR. MCKINNON:

Mr. Lipton, to what extent does Article 2.3 preclude any other in-state use of royalty oil? It's the article that gives up ALPETCO's first option.

MR. LIPTON:

Yes.

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MR. MCKINNON:

Another (indisc.)

MR. LIPTON:

As I read the.... As I read Article 2.3, this, in a sense, gives the group the right of first refusal over other oil insofar as is necessary to make up any deficiency out of Prudhoe. They are not entitled to more than 150,000 barrels a day. So, it depends on what your total volume of oil.... it doesn't preclude other sales necessarily, but it gives them, you know, the right of first refusal.

MR. MCKINNON:

Is that only for a deficiency out of Prudhoe?

MR. LIPTON:

I think so. Either a deficiency or, in the context of the other articles, if the other oil is priced lower in royalty value, then they substitute royalty oil from Prudhoe.

(indisc.), do you read that....?

MR. MCKINNON:

Yes, that's the way I interpret it.

MR. LIPTON:

This is the way that I interpret it. But, basically, the state is not committing more than 150,000 barrels of oil a day.

MR. MCKINNON:

It's my understanding that the provision, assuming that ALPETCO was taking out 150,000 barrels a day, well, say, 100,00 barrels (indisc.) at a cheaper price, that ALPETCO would have the option of replacing 100,000 barrels of their 150,000 (indisc.) under Prudhoe, with the other 100,000 being offered at a cheaper price.

MR. LIPTON:

I think that's right. They may have the right to substitue. But, in toto, not more than 150,000 barrels a day.

MR. MCKINNON:

To what extent does that serve to extend this contract beyond its twenty-seven year deadline?

MR. LIPTON:

I don't believe it does.

MR. MCKINNON:

Well, the provision is that they all shall be offered to the buyer at the same price on the same terms and conditions as offered to third parties. Twenty years into this contract, the State makes an offer at a certain price with a twenty-year term....does that mean that ALPETCO gets the option to....

MR. LIPTON:

I would assume not. But, look, this is a legal interpretation of the contract. I would think that any reasonable man, which means not necessarily and attorney, would interpret this to mean the right to lift the twenty-seven year duration of the contract, and not because there is an offer of royalty oil elsewhere which may be available in the twentieth year of the contract, then for fifteen years they would have the right to extend it.

But, this is a legal interpretation of the contract. I would certainly not think that this is the intention of the drafters, either way.

MR. MCKINNON:

I didn't think it was, but I'm certain that it may have that effect.

MR. LIPTON:

Yes.

CHAIRMAN MILES:

Mr. Lipton, you mentioned before, and again tonight, that in any project of this particular nature the first five years may be rocky from a financial standpoint. They may be fairly tough.

MR. LIPTON:

Well, not necessarily. I mean there are capacities that come on-stream that are just at the right time of the cycle, and the first five years are magnificent. It's just that, again, I'm not making this as a prediction, I'm saying this is what the risk is for Alaska. But, if it works out that way, then it's a risk.

CHAIRMAN MILES:

I know you're not making that as a prediction, but you indicated that is a possibility and you use a five-year term (indisc.). When exactly does that five-year rought period begin? Does it begin after Legislative approval?

MR. LIPTON:

No, no. The five years I'm concerned about is the five years after coming on-stream, after starting. Because this is the time when all of the work has been done, the capital has been invested,when the contracts are beginning to be supplied. And then when you're worried about do you have

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the volume to get optimum utilization of your capacity and, therefore, relatively low unit costs so you're getting the prices you had anticipated. And, in the first five or six years, at the start of an operation like this, the cash flow can be decisive for the survival of an operation.

MR. PARR:

Mr. Lipton, I'd like to make some rather flat statements in coming back to things that have been (indisc.) before (indisc.) things that I've understood from you cannot, as near as possible, get yes or no answers (indisc.). If I understood you correctly, one of the risks to the State is that this refinery, or this petrochemical plant, may have difficulties somewhere along, (indisc.). And the State is going to have to wind up getting to bail it out by going in and putting in equity into the petrochemical plant.

MR. LIPTON:

No, I didn't say putting in equity. I thought maybe modify the price at which the royalty oil is being delivered to enable them to survive in the face of a difficult cash (indisc.).

MR. PARR:

I thought that you had said both of those. I misunderstood you, then....only the one of having to lower the price of the feedstock....that's the only one.

MR. LIPTON:

That's the most immediate one that occurs to me.

MR. PARR:

Looking ahead to 1983 or '84, or whenever (indisc. - cough), in petrochemicals, we are looking at a seller's market rather than a buyer's?

MR. LIPTON:

I'm not at all sure of that. Not at all convinced.

I know why. Because what you have is a projection of chemical demand, and, if you're projecting demand at six or seven percent, which is sometimes done, then what you speculate is that it needs so much capacity and, if it isn't forthcoming, you've got a seller's market. But turn it around. Let the expectation of a lot of companies in the chemical industry bid the demand goes up six or seven percent, and let demand go up four or five percent. The expectation of a six - seven percent growth means a lot of investment capacity. And the growth of four or five percent means you've got a buyer's market, not a seller's market.

It's very.... You know, the chemical industry, among others, goes through fantastic swings. And one of the reasons that it does - one - not all of the reasons it does, is that you tend to have a lot of companies make simultaneous investment on the basis of the same expectation. And, if enough of them expect the same thing to happen, then all of them become frustrated because the capacity goes in.

MR. PARR:

Has that resulted in, let's say, petrochemical plants being built in bunches and skipping a number of years and being built in another bunch?

MR. LIPTON:

They tended to be, yes. Very definitely.

MR. PARR:

Everybody has seen the possibility all at once?

MR. LIPTON:

Pretty much so. There's a lot of that. There's a great deal of that. It's not.... As I said, that's one factor - far and away from the whole story. A lot of it has got to do with when oil companies went into the chemical industry and why they did and under what circumstances, and changes in technology A lot of these things happen.

But, certainly, one of them is that, if you've got a competitive industry that sees things through the same set of glasses.

MR. PARR:

Another thing we've been told and, again, I'm using my own words, which may not be exactly the words that were used, but is it because of the imbalance in trade between Japan and the United States and the strong economic pressures that make Japan interested in taking a U. S. export of this sort? Now the question of the dollar and the yen thing didn't even come into this, this was even disregarding the dollar and the yen....

MR. LIPTON:

Yeah, sure, but there are a lot of ways Japan can do it. One way is to buy petrochemicals from Alaska, another way is to build automobile factories in the United States.

MR. PARR:

I didn't say, necessarily, in this particular instance....

MR. LIPTON:

I think it's a factor, but with all of the direction you have over industry from government in Japan, there's a limit to the extent to which public policy is going to lose to uneconomical commercial decisions.

MR. PARR:

I had gotten the impression from the testimony we had before that it's not such a marriage between government and big business in Japan, but it is a Siamese twin relationship. Which means that political decisions might well govern.

MR. LIPTON:

Well, maybe commercial decisions and government-political decisions?

MR. PARR:

Possibly.

Thank you, Mr. Chairman.

MR. LIPTON:

Excuse me, can I just expand on that for a moment?

The Japanese have always been interested in security of supply, and that's a combination of commercial and political decisions. And Japan has looked at Canada many times, under many different circumstances as a potential secure source of petroleum. Not necessarily to export to Japan because, come an emergency, they're not likely to, but if they have their own position, it becomes the basis for an exchange, or international balance of oil flows may be affected by their position. And there's no question but that it is widely believed, and the Japanese have held it out, that they will pay premiums for security of supply.

But, when it comes down to it, we've been involved in several of these projects. They will. But, the amount of premium that they are prepared to pay for security of supply is within manageable commercial limits. There is a limit to what they will do for it. And this had to do with the question of the Japanese investment in the (indisc.), that's all. All right?

CHAIRMAN MILES:

I'd like for you to go back over the industrial profile of the point that you made with respect to Saudi Arabia. I think I understand the situation on the West Coast and what large producers' situation is. I didn't fully understand the industrial

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profile point that you made.

MR. LIPTON:

On the petrochemical investment there?

CHAIRMAN MILES:

Right. Insofar as it may, or may not, relate to Japan and the other Pacific (indisc.).

MR. LIPTON:

First, let me start with the competitive disadvantages of a petrochemical facility in Saudi Arabia, which are very similar to the problem of Alaska. One is that construction costs and capital requirements are very, very high. Secondly, your market is a distant market. Therefore, if you have to move your chemical products to the market, it costs more to move the chemical products to the market than to move the feedstock embodied in the crude oil. So, you're bucking up against a transportation disadvantage.

Now, the starting point to overcome that is, particularly in Saudi Arabia, is the availability of huge quantities of ethane, associated with their whole gas-gathering system, all of which they've been flaring gas at a fantastic rate. Now, if you look realistically at a world-scale ethane and ethylene-related operations in Saudi Arabia, and try to calculate at what price the ethane would have to go into an ethylene operation in order that the combination of feedstock cost, capital cost, and transportation cost would allow you to sell competitively in Europe or Japan, you come up almost inevitably with negative prices on the ethane. In other words, the Saudi Arabian government would have to supply the ethane at zero price and maybe pay to take the ethane. But the Saudi Arabs, from the very beginning, negotiated not in simplistic terms. They were talking in terms of a combination of operations in which the ethylene project would be jointly owned, they would put capital into it, your derivatives would have a different financial structure. And, in fact, if you put together everything, which is a very low price on the ethane, and a very, very low price on the capital, which the Saudi Arabs would largely provide, you'd begin to get close, maybe, to a competitive situation. But, probably not. I doubt very much if, at least what we have seen, anybody would voluntarily move into Saudi Arabia and, even on that basis, just build a plant.

But what they have to offer in addition to that, and they've held this out since 1975, not in 1974 - in 1974 everybody was coming to Saudi Arabia and begging them - and by 1975 they were asking Saudi Arabia, if you want to marry us, what kind of a dowry do you have? You know, the things had turned around by then. Well what they have to offer is this. Look, if you won't do this on the terms and circumstances which we will

together negotiate. In addition, the way we sweeten the whole investment project is by making available to you, not as feedstock to the project but for export purposes, for a given amount of capital investment, say a hundred thousand barrels a day of crude. Now, the further you push this project down the road, if it comes on-stream in 1985, you still may be in a difficult chemical environment. But, sooner or later, the project will pay out. But, meanwhile, if you can start gaining access to a hundred thousand barrels a day, a hundred-fifty thousand barrels of Saudi Arab crude, which is the most important and predictable source of world oil reserves for the long-run, over a period of time this becomes tremendously valuable. In the same sense, if you had said to a developer here in Alaska that we will sell you a hundred and fifty thousand barrels a day of royalty crude to do this investment, but, on top of that we will give you for export, beginning in 1990, another 50,000 barrels a day of Alaskan crude that you can do anything you want with, you've created an entirely different situation. This is what the Saudi Arabs are doing.

And this is why, what is essentially non-economic chemical capacity to a limited extent, and I don't think everything that's been booted about will not come to fruition, but I would guess three world-scale projects are reasonably well-assured at this date. It may come in largely because the Arabs have something else to offer, which is access to what will in the future be, scarce world oil reserves when the rest of the world is close to operating at productive capacity. The exspansible source of crude oil reserves production for the world will be Saudi Arabia.

CHAIRMAN MILES:

Let's just speak in terms of Japan now. From Japan's standpoint, would Japan rather have a source of Saudi Arabia or a source of Alaska?

MR. LIPTON:

Saudi Arabia. Saudi Arabia. You're talking about finite reserves here in Alaska. Unless, if things really work in exploration and turn Alaska into a fantastic producing province, is one thing, but we're worried about whether or not Prudhoe Bay will support twenty-seven years of a hundred-fifty thousand barrels a day (indisc.) crude. I'm not talking about Saudi Arabia producing a twenty million barrels a day, which was the expectation some years back, but whatever the demands upon Saudi Arabia, we are facing the year "x", and I don't know exactly when it is, when virtually most of the world will be operating at very close to capacity. And if the world is looking and saying, where will the next barrel of oil come from? - it will come from the reserves in Saudi Arabia.

And this is the most precious commodity they have, an expansible source of supply. It's not a bottomless barrel the way we thought in the 1950's, but it is, for the rest of the world, an expansible source of supply. And it becomes an extremely critical place for companies to go, and, if you'll notice, most of them go through Asia, which are going on into Saudi Arabia. They are companies that want either to improve or establish an off-take position in Saudi Arabia, which heretofore had been dominated by the members of ARAMCO (ph).

CHAIRMAN MILES:

I don't understand that. If we can assume for a moment we are talking about a hundred-and-fifty thousand barrels of oil from Alaska and a hundred-and-fifty thousand barrels from Saudi Arabia, I don't know if it's reasonable to make that kind of very narrow assumption. It would seem to me that, and again, relating to Japan, that they would rather have Alaskan source, if they could get the long-term commitment of.... mainly because of political stability.

MR. LIPTON:

I'm sorry, I misunderstood you.

If it's nothing more involved than an "x" number of barrels, and a price and competitive situation is about equal, they would rather have it Alaska, and they might even pay a premium... some premium for Alaska, but not very much. What I'm saying is it's not "x" barrels against "x" barrels. In Saudi Arabia it's "x" barrels plus. This is basically what they are getting in Saudi Arabia. They are establishing a position which gives them preferred access, not according to their feedstocks, but the off-take of crude oil for export purposes. This is the big thing. And in Iran, where so far the Shah has been unwilling to do this, the Japanese have been negotiating the petrochemical operation for years and years, and they haven't been coming anywhere on it. And only, I think, if they're going to be something which gives them more than just access to feedstock, because Iran is as unattractive a place to put export capacity and chemical industry as Alaska or Saudi Arabia. One doesn't go into these areas just on a purely commercial basis, I don't believe.

CHAIRMAN MILES:

Thank you.

MR. CHATTERTON:

Excepting the news of the last thirty-six hours or so, do you rat the "economic climate" in the Kingdom of Saudi Arabia any less stable than the economic climate in the State of Alaska?

MR. LIPTON:

It's a damn sight less stable than the climate of Alaska. Sure. I mean, if you're assessing political risks, there's just no question about it. No question about it.

MR. CHATTERTON:

Thank you. Thank you, Mr. Chairman.

SENATOR HACKNEY:

Mr. Chairman, the only time I ever heard Mr. Lipton really put in a box was the time when somebody sat at a position just about like this and they said, "Mr. Lipton, if you were sitting in my seat in the Senate, and this (indisc.) before you at the present time, and you had a green button and you had a red button, which button would you push?"

MR. LIPTON:

Remember what I said?

SENATOR HACKNEY:

Yes, I do. Push the green button. Would you push to green button in this case?

MR. LIPTON:

I don't remember saying push the green button. I think what I said was, if you'll give me a vote on everything else you can vote on the Alaska Legislature, then I'll vote on that issue.

MR. PARR:

Mr. Lipton, what you said, in effect, I think, greatly over-simplified, is we accept this deal. It's a pretty good contract. The real thing is ALPETCO is taking some calculated risks, and they are using their best judgment in this area. And the State, of course, if we go over the contract, essentially takes the same kind of risks. And you have not said whether you think it's a good risk or not. Maybe it's not in your field, I don't know.

MR. LIPTON:

See, I can't say that without being a Legislator who weighs everything in the balance. That's the difficulty. I don't want to overplay the risks here. And I do think it's a contract which, under the circumstances, was started from very little interest from anywhere around. It represents a maximum effort

on the part the group, and it represents a maximum effort on the part of the people who drafted the contract to protect the State.

The question is, how do you assess the value of the whole thing? There are risks.

MR. PARR:

Nobody, who is very much interested in security, comes to Alaska in the first place. If they do, they don't stay. It isn't that kind of place. On the other hand, what I think most of us try to do is try to assess the risks as carefully as we can, and which, I think, is where we are hoping you can help us. If the gamble seems like a good gamble, we will go. If it's a poor gamble....

MR. LIPTON:

Let me try. You're asking me very straight-forward questions, and I try to give you straight-forward answers, but does it make my answers correct? Then I give you a judgment.

I think the biggest risk is that the contract will collapse, as we personally assess the probability of success as not all that great. And this is the risk. Now, what's the cost to Alaska if it does? That is, if an honest effort has been made and you've got this protection, and, whether it's eighteen months or twenty-four months, the ALPETCO group will be out a considerable amount of money. What has Alaska lost? It's a subtle thing. I guess you don't have the answer to that, but let me tell you the impression I have.

Alaska has been involved now in a series of episodes involving contracts with off-takers. And, first, it was on the joint resolution of the Legislature and then it was on the sale of the royalty gas - all for a specific purpose. Has Alaska suffered because of this? Well, at some point, if there is misadventure after misadventure, questions begin to arise about how solid is the thinking up there in Alaska about these things. If the contract doesn't come to fruition in the nineteen months or the twenty-four months, I don't think Alaska has lost a great deal. But, it's just become one more episode. But, I think that's about the greatest risk.

The other risk is that everything is going to go, and the investment's all going to be made, and it may lead to a very, very difficult time. And you may be faced with things which, under the contract, you do not anticipate; that is to say, a real sense of responsibility on the then-administration in the State of Alaska and the Legislature at that time that, hell, we can't let this go down the drain. Maybe that's not all so bad, because, if the thing does come to fruition - if

you have to hold for five years or seven years - that's not in the contract, but that's a risk you may have to do this, and it may not even be all that bad.

But, if you're asking me honestly to give you a personal judgment, that we've all discussed, it seems this is the way we assess it. Now you've got to decide whether, if the worst of these come to fruition, how much does Alaska suffer by it? I can't answer that question, but this is about the way which we will try to evaluate. The biggest risk and the highest probability, I think, is that it will not come to pass. What does it cost you? You decide now.

The other risk is way down the road, and then you may face things that your successors will feel obligated to do, even though the contract doesn't call for it. They may not be so terrible, if worse comes to worse, and if it turns out to be only a short holding operation. But, these are risks.

CHAIRMAN MILES:

You're talking about another set of risks if everything goes, and then some new unforeseen, or heretofore undiscussed, problems (indisc.). What does.... Okay, what are some of those that you haven't yet discussed?

MR. LIPTON:

Well, look....that every step along the line the project looks like it's working out, then the fact you do have off-take contracts. And on the basis of the off-take contracts, commitments are made to finance, whether it's net capital or whether it's equity capital and joint ventures, but commitments are made, because everybody perceives step by step down the line that it's working out. And on that basis, ALPETCO has performed according to the due dates of the contract. But, then, about the time when.... While all of this is going on, other people are making their own investment decisions, too, in similar expectations, and it turns out that, when the first crude oil is being processed, and the first gas oil from the refinery is going into an ethylene operation, and naphtha is being cracked, and products are coming out, all of a sudden you don't have as firm volumes, which changes your average cost of processing, and the prices are somewhat lower than have been anticipated in all of the calculations, because nobody is committing you to a firm price in the future. You are going to have to meet competitive prices, whoever is doing this operation. This could put an on-going operation in a cash bind for some time. And that's not a matter of something unforeseen happening. Everybody who is looking at this is willing to acknowledge that this could happen. These are the

imponderables that happen in the world chemical industry. All I'm saying is that at that point the State of Alaska may be faced with commitments they feel obliged to undertake, which go beyond that of the contract, simply because this is one of your major investment projects in Alaska. And, one way or another, you are not going to allow it to founder for the lack of cash flow.

MR. CHATTERTON:

Then the obvious way to help it out is to reduce the cost of the feedstock.

MR. LIPTON:

Yes. Sure.

MR. CHATTERTON:

Thank you. Mr. Chairman, if I may continue....

This point that you raised earlier of petrochemical plants, etc., even product refineries, "they sort of come in bunches like grapes - they're all built".... The possibility that you pointed out of getting into a cash flow problem after this deal is on-stream, was it in the late fifties or early sixties where there was a situation - as far as I know in Canada and also (indisc.) - with the market for sulfur (indisc.) out of gas?

MR. LIPTON:

Oh, yes....the sulfur problem. Yes....sure. Just let me say this, too. It's not my purpose to put a dark light on this, because none of these things might happen. But, if you've gotten beyond what is the point of no return on the project, you can even, the ALPETCO people or anybody else, foresee problems ahead. But, once you've passed the point of no return, the work having been done, you don't stop the project. One goes ahead.

There is a point at which capital has been committed and construction is going that one goes ahead and completes the project. Look, I don't mean.... I know I sound like.... I don't mean to come here, you know, and preach Doomsday here. It could work out just the opposite way, but my responsibility is to the Legislature, and I feel one of the things I must do is discuss what the uncertainties and what the risks are.

MR. CHATTERTON:

Mr. Chairman, I guess it's just human nature, even though you see if by any chance things look rocky ahead, why you can proceed to build your mind up until you want that (indisc.) as large and as glistening as possible, because that may be the last way to do it right.

MR. LIPTON:

I wasn't really thinking of that. That's probable. But, what I was really thinking was that in an investment process the way in which you evaluate the profitability of an investment decision is always what is the incremental investment and what we will get back from that. And there comes a point when you've sunk so much money that it's not a matter of whether what you've already invested pays out, but it's the incremental investment, and what do we get in return for that.

Of course, the classic story of that, and forgive me for bringing a New York episode into it, but this goes back to the 1930's when one of our most famous public servants, Bob Moses, was at that time - later on he built everything - but, at that time, he was in charge of the New York State Recreation Department, and he decided to build Jones Beach, which has become a monument in due course. He asked for an appropriation for Jones Beach, and there was no way in which the state legislature was going to give him those funds. They gave him the funds which they thought were appropriate. And he took all those funds, and he built the foundation for Jones Beach. Then he said, "Now I've got the foundation - give me the rest of it." This is incremental investment decision-making.

UNIDENTIFIED SPEAKER:

The (indisc.) is alive and well and living in Alaska.

CHAIRMAN MILES:

Can you give us an over-view of how this decision, Mr. Lipton, might relate to the other decisions regarding financing of gas line, gas liquids, the structure in which we might be viewing those various decisions? As you know, we are being asked to participate in - the Northwest Gas Line - make a decision whether to (indisc.). Can you kind of give us your over-view?

MR. LIPTON:

I don't think that your decision on the royalty crude contract ought to be contingent upon what may, or may not, happen on the gas. I think that the probabilities of being able to use gas liquids as the basis for industrial development as an

alternative to this are really not much more exciting. I think probably they are more difficult. I think they are more difficult.

You've got a lot of problems on what you're going to do with your gas, when is it stripped, who's going to strip it, is it (indisc.). These are a lot of very difficult problems. They are too elusive right now to try to come to grips with all of them. I would say that we don't feel that your decision on the royalty crude contract now ought to be conditioned in the probability or improbability of what may happen to the gas liquids.

We have been very excited about what may be done with gas liquids. As you know, for many years we first talked about gas liquids probably being of greater significance to Alaska, per se, than the natural gas itself. It's not as though you are going to be energy-short in Alaska. But when you start looking at the specifics of it and, even what we have mentioned on several occasions, which is thinking small instead of big at Fairbanks, there are a hell of a lot of problems that show up. Now, things may still be done, and there are a lot of permutations and combinations, but I think you would be ill-advised at this stage of the legislative process, or the royalty disposition process, to try to condition your decision on this project in terms of what may, or may not, be done with natural gas.

CHAIRMAN MILES:

Thank you. Mr. Lipton, thank you very much. Do you have any closing remarks?

MR. LIPTON:

No, except to express my appreciation for the courtesy you have extended, and I have enjoyed this conversation very much.

CHAIRMAN MILES:

Thank you very much.

Shall we adjourn until tomorrow night - same time, same place?

3/16/76

Present:

Osterwalder

Greening

Miles

Parr

Challenger

Battelle Northwest Presentation

Tussing

AGO 545621 +

1. What is the likelihood that the ALPETCO project will be commercially viable?

   (a) Comment on the "Alaska disadvantage" and on how ALPETCO might overcome it?

   (b) Comment on the realism of ALPETCO's marketing plans for Japan and for the U. S. West Coast.

2. Is it possible or likely ALPETCO could get its project financed without an overwhelming assurance of its commercial feasibility?

3. What would happen if the ALPETCO facility were financed and built, and after its completion it were to be unprofitable? What would be the consequences for ALPETCO's sponsors, for the bondholders, for the employees, for the community in which the plant was located, and for the state?

4. If ALPETCO were to encounter difficulties either in financing the project or in operating it profitably, what other assistance, if any, would ALPETCO be likely to ask from the state, apart from a discount on crude oil prices? What would be the costs, risks or other implications for the state from these measures?

5. What will be the likely impact of the ALPETCO project on the West Coast oil market and on the value of Alaska crude oil generally, both before and after the proposed facility goes on stream?

6. Comment on sections 2.3 and 2.4 of the contract, specifically the option to buy non-Prudhoe royalty oil.

7. Comment on the procedures by which the Commissioner of Natural Resources and the Royalty Board decided to negotiate this contract.

8. How can the Legislature best resolve the factual, legal, analytical and policy questions presented by this contract?

Tussing

3+M See Report

ALPETCO CRUDE OIL RESALE SCENARIO, 1980

September 1977 Data
(Bonner and Moore)

Destination:	Alaska	Cherry Point	California	Gulf Coast	Total
Volume(mb/d)	82.5	452.1		178.8	713.3
					Weighted Average
Value at destination	12.50	13.30	13.38	13.77	13.35
less transportation from Valdez	(-)	(.60)	(.82)	(3.05)	(1.21)
Value at Valdez	12.50	12.70	12.56	10.72	12.13

					Total
Arco volume (mb/d)		143.0			143.0
Exxon volume (mb/d)	2.9	139.0			141.9
Sohio volume (mb/d)	74.4	141.6		167.5	383.5
Total Volume (mb/d)	82.5	423.6		178.8	713.3
1980 distribution (Bonner and Moore)	73.0	300.0	302.0	525.0	1200.0
Assume Alaska and West Coast Sales Distributed among Companies in Same Proportion as 1977:					Average Valdez Price
Arco volume (mb/d)		190.4		49.6	240.0 12.23
Exxon volume (mb/d)	2.6	185.1		52.3	240.0 12.21
Sohio volume (mb/d)	65.8	188.5		390.1	644.4 11.46
Total volume (mb/d)	73.0	602.0		525.0	1200.0 11.79

The 1980 price to Alpetco would be $11.79 (less pipeline tariff).

AGO 545623 +

(1) ALPETCO would lose money marketing this crude oil at the U.S. Gulf. (Cost $11.79 + transport $3.05 = $14.84; value at Gulf cost is only $12.77.)

(2) Therefore ALPETCO must make room for this crude on the West Coast. (Cost $11.79 + transport average 71 cents = $12.50; value is $13.34; potential profit 84 cents.)

(3) But ALPETCO has to compete the market away from other producers. 150 mb/d is a very large part of a total market of 602 mb/d. Prices will have to come down.

(4) ALPETCO is willing to resell its oil at 2 percent over cost. Therefore it will accept a Valdez price of $12.03. Suppose it is able to make room for all 150 mb/d at this price.

(5) SOHIO with an average Valdez cost of $11.46 could easily defend its market share. Competition between ALPETCO, SOHIO and California producers would tend to drive West Coast prices down to ALPETCO's minimum price $12.03 plus tanker charges; Alaska prices would likely fall by the same amount to $11.90.

(6) Assume a price elasticity of demand for Prudhoe-grade crude oils on the West Coast of - 1; West Coast sales would increase by 30 mb/d. Assume ALPETCO's West Coast share is carved proportionally out of the other producers' shares. Therefore, the new prices and volumes would be:

Destination:	Alaska	West Coast	Gulf Coast	Total	Average Price
Value at destination	$11.90	$12.74	$13.77		
less transport from Valdez	(-)	(.71)	(3.05)		
Value at Valdez	11.90	12.03	10.72		
Arco mb/d		153.1	56.9	210.0	11.67
Exxon mb/d	2.6	148.8	61.2	210.0	11.79
SOHIO mb/d	65.8	151.5	346.6	563.9	11.20
ALPETCO mb/d		150.0		150.0	12.03
TOTAL mb/d	73.0	632.0	495.0	1200.0	11.48

The new priced ALPETCO would be $11.48.

$e = \frac{dQ \cdot P}{dP \cdot q}$

$e = -1$

AGO 545624

(1) If the process stopped here, Alaska would be losing at least $69,285 per day, $25.3 million per year as a result of ALPETCO's resale effort (31 cents per barrel on 150 mb/d royalty, plus tax of 7 percent of 31 cents on 1050 mb/d).

(2) ALPETCO, under the new circumstances, would be entitled to its royalty oil at a new, lower price of $11.48.

(3) If, as is likely and contrary to the above assumption (4), reduction of the Valdez price to $12.03 were not sufficient to penetrate the West Coast market with 150 mb/d, ALPETCO would still lose money on any crude oil it sold at the Gulf (cost $11.48 + $3.05 transportation = $14.53; value is $13.77).

(4) But ALPETCO could still undercut the prevailing West Coast price of $12.03 plus transportation from Valdez, and increase its market share, if it was still willing to sell at cost plus 2 percent = $11.71.

(5) Where would the process end? We don't know, but equilibrium would be reached only when the Valdez price for oil shipped to all destinations fell to the same value: $10.72. In this extreme case, ALPETCO's resales would cost the state $239,145 per day, or $87.3 million per year ($1.07 per barrel on 150 mb/d plus 7 percent of $1.07 on 1050 mb/d).

April 7
reasonable depths

5':25' Channel 2 or 3

1

half hour

Alaska State Legislature

POUCH Y, STATE CAPITOL
JUNEAU, ALASKA 99811
907 465-3800

TRANSCRIPT OF TESTIMONY OF

DR. ARLON TUSSING

March 16, 1978

BEFORE THE SPECIAL COMMITTEE ON ROYALTY OIL AND GAS

Committee:

Senators:	Representatives:
Chairman Mike Colletta	Chairman Bill Miles
Pat Rodey	Chat Chatterton
Bill Sumner	Joe McKinnon
John Sackett	Charlie Parr
Kay Poland	Al Osterback

DR. TUSSING:

You all know who I am, and I won't waste time on introducing myself. I have a number of questions I intend to address myself to this evening, and let me run through the questions which I would deal with, if I have the time, which I won't, and we'll try to be selective. What I'll do is I'll take up one issue at a time, and let you discuss....let's have some interchange during the discussion. I won't have a formal presentation. We'll just take these issues up. Feel free to interrupt me if there is something you are not following.

Here are the issues that had been identified as possible areas for my treatment on which I'm ready to comment. First, what is the likelihood that the ALPETCO project will be commercially viable? And under that, comment on the Alaska disadvantage and how ALPETCO might overcome it. Second, comment on the realism of ALPETCO's marketing plans for Japan and for the U. S. West Coast. Third, is it possible, or likely, ALPETCO could get its project financed without an overwhelming assurance of its commercial feasibility? Fourth, what would happen if the ALPETCO facility were financed and built and, after its completion, it were to be unprofitable? What would be the consequences for ALPETCO's sponsors, for the bond holders,

AGO 545627

for the employees, for the community in which the plant was located, and for the State? Fifth, if ALPETCO were to encounter difficulties, either in financing the project or in operating it profitably, what other assistance, if any, would ALPETCO be likely to ask from the State, apart from a discount on crude oil prices? What would be the cost risks or other implications for the State from any of these measures? Sixth, what will be the likely impact of the ALPETCO project on the West Coast oil market and on the value of Alaska crude oil generally, both before and after the proposed facility goes on-stream. Seventh, comment on Sections 2.3 and 2.4 of the contract, specifically the option to buy non-Prudhoe royalty oil. Seven, comment on the procedures by which the Commissioner of Natural Resources and the Royalty Board decided to negotiate this contract. And eight, how can the Legislature best resolve the factual, legal, analytical, and policy questions presented by this contract.

Of all of these things, I think that the Battelle presentation has set the background for discussing some of the issues which relate to the West Coast surplus. Firstly, let me say that the West Coast surplus will have, and is having, a consequence that the Battelle study did not point up and that is in exerting downward pressures on West Coast oil prices. And, as the West Coast surplus increases, those downward pressures will increase. I will want to show you in a brief scheme how these downward pressures are likely to work.

Taking a series of hypothetical prices at Valdez - these are net back prices at Valdez for shipments to various parts to various markets based upon what net back prices were posted by the company in September of 1977, with some modifications, but, essentially, the sales in Alaska to Alaska refiners were at $12.50 a barrel; that is, as of Valdez. West Coast sales were at an average of $12.63. Gulf Coast sales were at $10.72. And this reflects the differences in transportation costs to those markets, as the average transportation cost from Valdez to the Gulf Coast was $3.05, while the average transportation cost to California was $.82, and to Cherry Point $.60. And this is what results in the difference in Valdez price.

Okay, now let's move forward to 1980 and assume that nothing changes in terms of the real prices of oil, that the OPEC price in real dollars, remains constant, and the transportation costs remain constant. And that, of course, assumes that for the Gulf Coast price to remain constant and assumes there will be no higher prices.

CHAIRMAN MILES:

Doctor, are you sure that your figures are right there - $12.50

AGO 545628

at Valdez price for sale in Alaska and a higher sale for the West Coast?

DR. TUSSING:

Yes. I'm not sure these are right. I took this figure from Bonner and Moore, who claim to have derived it from state revenue figures. Since I had just one day to prepare this, I had to grab the only materials I had at hand. I didn't have a chance to go to the original data. Whether or not this is precisely right is irrelevant to the thrust of my explanation. What I am dealing with is the large difference between the West Coast and the Gulf Coast net back, and Battelle set out the same thing. They had different numbers, but they were in the same order of magnitude - roughly, a $2.00 difference in the net back price from the West Coast and the Gulf Coast.

As you know, ARCO was able to market most of the oil through its own West Coast refineries; EXXON, a somewhat smaller proportion; and SOHIO, with no outlets of their own on the West Coast, must ship most of their crude to the Gulf Coast markets. Now projecting ahead the shares of the various markets to 1980, and assuming 1.2 million barrels per day, which is more than is going to be produced at this stage - but, again, it's a minor....I'm not trying to predict the future in this - but, projecting the differences, we have for ARCO an average net back price at Valdez of $12.23, for SOHIO, an average net back price of $12.21 - not for SOHIO....for EXXON, SOHIO - $11.46, and for a total, including the other minor companies, a weighted average price of $11.79.

Alright, now, what we see here is that the cost of oil for SOHIO is more than a dollar under the West Coast price. It's an interesting situation, which in our competitive textbook economics would say would not last very long because SOHIO, rather than accept this price for its oil, would want to penetrate this market for every barrel, additional barrel, that SOHIO could put into the West Coast market. SOHIO would make $1.17 more. Our textbook market economics would say SOHIO would keep trying to sell oil on the West Coast until - what would happen if SOHIO tried to sell more oil out on the West Coast? They would drive this price down. In other words, to make room in the market, they would have to offer a discount because ARCO and EXXON are selling all they can at this price, or moving all they can at this price - the biggest customer is SOCAL - to displace more Saudi crude out of SOCAL's supply, or, for that matter, to convince refiners to not to take oil somebody else. So, SOHIO would have to offer a discount. Now, SOHIO would be ahead as long as it could get more than $11.46; that is, on the last barrel. The reason SOHIO doesn't do this is that by pushing more crude into the West Coast they are not just making....suppose they offer it on the West Coast for

$11.63, for a dollar discount. Well, they are making the difference between $11.46 and $11.63 on that incremental barrel but, in the meanwhile, they are provoking the others to cut their prices, too, to maintain their market share. The California independents will cut their prices to maintain their market share. So, all the producers would end up worse off than they were before, as they would all end up selling roughly the same amount of oil into the West Coast market. But all of them would be getting less, and the state would be getting less. So, SOHIO, because it's such a big element in the market, suffers most from its own competitive actions. SOHIO is not about to start a price war which will drive the West Coast price down.

Other than that, with the growing surplus, SOHIO really does want to market this. One of the things that came out in the suit of the Maritime Unions against the Virgin Island Exchanges - what was doing was SOHIO was swapping its oil with SOCAL; it was delivering its oil to SOCAL and taking SOCAL's Saudi crude and selling the Saudi crude in the Virgin Islands at a discount. They weren't discounting on the West Coast. They were posting their net back prices in Alaska as if they were selling it in competition with Saudi crude on the West Coast. Yet, they were taking a loss on the Saudi crude they sold in the Virgin Islands. So, in effect, they were discounting without it appearing on the books, and the State of Alaska was getting royalties and severance taxes on the basis of a crude price which was higher than the true value - the market value - of the crude. In other words, SOHIO was willing to pay a higher royalty and a higher tax than it had to, based on the true value of the crude in order not to appear to be pushing down the West Coast price.

This was what was happening with production at less than 700 million barrels a day - 700 thousand barrels a day. As production gets up to 1.1, the downward pressure of the temptation of any of the producers to try to get more of the West Coast market. All of them can do better on the West Coast than they can.... Their average price is lower than the West Coast price. They can all do better so long as that's the case.

Now, if competition broke out, what would happen is the West Coast price would be driven down to $10.72. The competition that each of these producers, say SOHIO, would keep trying to sell more oil on the West Coast. It could keep making more oil on the incremental barrel, on the last barrel, by selling it on the West Coast at a discount until they got it down to this price.- until they were making no more from selling on the West Coast than they made on the East Coast. If they could receive $10.73 by selling an extra barrel on the West Coast, instead of $10.72 by selling on the Gulf Coast, they would do it, if there were competition. Now, where does ALPETCO come

into this?

In a situation where the surplus is going to be increasing, at least until 1985, and I suspect it's going to continue to increase faster than that - the projections that were cited by Battelle that show it falling off are both pessimistic about future discoveries. By 1985 we are going to have the (indisc.) Sea sale, the lower Cook Inlet sale - will have been taken place long enough that if there are any discoveries to be made there they will ready to go on-stream. There will be, according to the Interior Department's schedule, seven more OCS leases off Alaska in that time, so that the supply may continue to expand far beyond the highest of those projections. While it's my belief we are in for a long period of low economic growth and low increase in energy demand, for reasons which you can see.

Now the economic management of the United States and the Free World is not really at its optimum, and I think that we're going to see very low rates of growth - of economic growth and energy growth, generally. So, we're going to have an increasing surplus on the West Coast, increasing downward pressure on prices if exports aren't authorized and if none of these proposed transcontinental pipelines are authorized. And I think the odds are against all of them. Anyway, you have continued downward pressure.

What does ALPETCO do? If it comes in as a petrochemical plant, it removes some of the surplus crude that otherwise tends to depress the West Coast price. It does not go into the petroleum market as such. And so a crude-base petrochemical facility in Alaska, or anywhere on the West Coast, if it used Alaska-type crudes, would reduce the surplus of crude on the West Coast, it would reduce the amount which has to be pushed through to the Gulf Coast. The weighted average price, the price that ALPETCO would have to pay under these assumptions, would be $11.79. They would be paying $11.79 essentially for oil that would otherwise have to be marketed on the Gulf Coast for $10.72. So there would be two effects of that. One is that the pressure on the part of the other producers to market their surplus on the West Coast, and drive down the price, will be reduced. The second is that the weighted average itself will tend to go up because some of this will be pulled out. Some of the $10.72 will be pulled out of the weighted average and replaced.... say, this is oil that SOHIO pays $10.72 for, will be reduced.... and, instead, ALPETCO will be paying the $11.79. So the weighted average will go up, and ALPETCO's price will be more than $11.79.

So everybody's price will be....the total price will be higher. So, (indisc.) in that context, any facility which removes oil from the West Coast market and reduces the pressures on the West Coast market, the surplus is favorable to the state. Now, as the Battelle people pointed out, the thing that is over-

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whelmingly most favorable to the state would be exports to Japan. I think that they made a good case that this is the best thing, under any circumstances, that could happen to the state. I think that the state has not devoted it the attention it might have to overcome the political bottlenecks. This is something that is a subject for another discussion, but I believe that exports could be authorized with the proper political strategy.

But, getting back to this.... Second best would be a petrochemical plant as opposed, say, to a products refinery which would simply push more oil into a West Coast market that's got more oil in. Now, (indisc.) from the petrochemical plant, however, to the ALPETCO proposal as a whole, there is another problem and one sees another picture. The proposed contract entitles ALPETCO to take up to 150,000 barrels, or up to its full Prudhoe Bay entitlement, of crude oil for re-sale up until the time their plant is ready to use it. Let's see what the effect of their taking that oil in (indisc.) will be. According to their pro forma financial statements, they intend to market their oil on the West Coast of the United States, and they intend to mark it up by two percent. Then they expect to earn a two percent margin on it and they give a puchase price of $7.00 at the well head, plus shipping costs to the West Coast of $.85, plus an ALPETCO margin of $.25, and tax (indisc.) for $5.40, and give a $13.50 sales price on the West Coast. Well now they're starting with different numbers and I won't quarrel with those, because they are based on other assumptions as to what the actual tax tariff will be and what the net back will be. But the problem here is ALPETCO takes oil that costs the $11.79 at Valdez, that is, well head price plus tax tariff, and there is no way that it can sell it on the Gulf Coast. ALPETCO gets 150,000 barrels, 140,000 barrels, of oil for $11.79. They lose money unless they can sell it for $10.72 plus transportation to the Gulf Coast, which is $3.00. So there is no way that ALPETCO can consider marketing on the Gulf Coast. ALPETCO, if it takes this oil, has to go into the West Coast. What can ALPETCO afford to do? ALPETCO says that it is looking for a two percent margin, so that brings its price at Valdez to $12.03. And, in that case, they can undersell the West Coast price by $.60. In other words, the value of North Slope crude oil on the West Coast as set by what the other producers are charging is $12.63. ALPETCO is getting its oil and is willing to sell oil for $12.60. I mean $12.03.

I really doubt whether, out of roughly 6 to 700,000 barrels per day of Alaska crude, which can be marketed on the West Coast, they are going to push in 130 or 140,000 barrels a day of it for only a $.60 discount. If you recall, ARCO will be moving all of its own oil through its own refineries. There is no way they could push ARCO's crude out of ARCO's refineries. EXXON

is going to be running a substantial amount of its own crude in its own refineries. Essentially, if ALPETCO is going to market this, they are going to have pretty much mop up the independent refiners who could accept the backing out of a very large portion of California independent production. And they are going to have to butt heads with SOHIO. They are going to have to undersell SOHIO at the CHEVRON refinery. Let's go back. There is no way they can sell Alaska royalty oil on the Gulf Coast. The only way they can sell it on the West Coast is to undersell SOHIO. And, essentially, they've got to undersell SOHIO at CHEVRON's refinery.

CHAIRMAN MILES:

Why would a CHEVRON refinery, an independent refinery, be willing to strike a temporary agreement with ALPETCO when they know that essentially they are going to have to go back to producers once the proposed facility starts producing petrochemicals?

DR. TUSSING:

Because there's a surplus of oil.

CHAIRMAN MILES:

Simply because of this?

DR. TUSSING:

Well, if you had a seller's market, which you don't have now and you won't have in 1980, and, very likely, you won't have in 1985. You certainly will have a buyer's market on the West Coast of the United States, at least through 1985. They are going to shop around.

Now, I'm not saying that the process is going to be perfectly competitive just because there's one seller. But now we've got a wild card in the deck. We have a different kind of seller. SOHIO will not behave competitively, will not use its full market power to capture its maximum market share on the West Coast because it knows it's spoiling its own market.

ALPETCO's in a different position, because to the extent ALPETCO drives down the West Coast price and can make a profit in doing so. Next month the composite average goes down if ALPETCO sells for $12.03. You can see SOHIO's getting their oil cheaper than ALPETCO is. SOHIO can defend its market position. SOHIO will not initiate a price war, but SOHIO will not be backed out, either. So SOHIO will go as low as ALPETCO can go, and it can go lower for the purpose of protecting its market

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share. Some of the California independents can't. And you're having this problem right now that Alaska oil is backing out California independent production. The Economic Regulatory Administration just gave an additional $1.79 entitlement benefit, or reduced the entitlement penalty, for the California producers by $1.79. And, thus, oil is still backing up California production. So those people, some of them can't back down. Some of them will make room for additional North Slope production, but you bet they will be in Washington and trying to get some new entitlements (indisc. - cough) or some other thing that prevents them from being backed out.

So, if ALPETCO can't afford to drive the West Coast price down to $12.03 and still make money. Unlike SOHIO, unlike ARCO, and unlike EXXON, they don't lose a penny by doing it, because they have no stake in the production of the rest. They have no production. They are a middle-man. And, to get this market share, they will go in and compete - they will engage in what textbook economics calls arbitrage (ph). And they will make their two percent, or they will make more than two percent on the arbitrage (ph). They don't have to take the full 150,000 barrels at once. They can start with a minimum of 10,000 barrels. You find a home for 10,000 barrels today. Give me 10,000 barrels of oil today at the composite average price, and I can find a home for it in California at $12.00. No question. I can find some California crude, or some SOHIO crude, that I can back out. So you take that next month. Meanwhile, you have driven this down a little bit and you've got a greater price advantage. Where does the process end?

If this becomes $12.03 - the West Coast net back price becomes $12.03 - the in-value price becomes $11.48, and here we get another round. And, so, where the process ends....it probably won't go all the way, but the only place that brings it to a definitive halt is when the West Coast price gets down to $10.72, which is the competitive equilibrium price. That is what your textbook economics would say is the natural price. That is the value of North Slope crude oil on the West Coast. Because, why should any producer on the West Coast accept this price, ship it to the Gulf Coast, and take a lower price if they could sell it for even a penny more on the West Coast? So the end of the process is this.

People tell me, or I have been told by people who are in these negotiations, that ALPETCO has no intention of taking this oil and marketing it. I know that Sea Train (ph) and Alaska Consolidated Shipping, which was the predecessor organization, had this as the main thrust of their participation, and they were most interested in getting an option on the royalty oil for the purpose of marketing. Now, I'm not urging any, or suggesting there's any bad faith here, I see no evidence that

any of the ALPETCO participants have ever thought this through. I know when I was on the Royalty Board the submissions (indisc.) asked of Consolidated Shipping, with respect to their proposal, were totally unrealistic because they were expecting to take oil at the in-value price and sell it on the Gulf Coast. They had professed letters of intent from purchasers on the Gulf Coast; they gave this as evidence they could do it, saying that we would take it at a price no higher than the lowest price at Prudhoe plus transportation cost.

Anyway, I don't know what their intentions are, and we'll get to how I think that the Committee ought to proceed in looking at some of these things a little later. But I can tell you that....with confidence, that just as Battelle sets out the case it would be a disaster for the state to market its own royalty crude oil, for the same reason, and perhaps even more so, a disaster if you let somebody like ALPETCO market the state's crude oil. The West Coast consumer will benefit, the national economic efficiency will benefit, but the tendency is to introduce into that market a major seller who has no stake in the business of an orderly market, who is not an oligopoly, profit maximizer.

Now, this moves on to something else. Let me put my statement to the Royalty Board in the record at some point. At that time I'd be reported on a survey I did for the Commission, mainly on the realism of ALPETCO's plans for marketing in Japan.

CHAIRMAN MILES:

Representative Chatterton.

MR. CHATTERTON:

Thank you, Mr. Chairman.

Doctor, did you say you wanted to....were willing to be interrupted before you switched to another subject?

DR. TUSSING:

Yes. Surely.

MR. CHATTERTON:

I have one question of you. This exercise we have gone through.... I think it's great, but aren't you analyzing just a small portion of the total system and not analyzing the system? Is not, with about 14 million barrels a day producible capacity today that Saudi Arabia has, and yet they're only producing about

8.7 million barrels per day....don't you think that they are the ones that control the West Coast price and not SOHIO? If you look at the total system?

DR. TUSSING:

If you look at the total system you see who controls the level of world prices. But the prices in individual markets vary according to transportation arrangements and local supply-demand situations. The Saudis control the price at the North Slope. If Saudis decide to cut back further on production to raise the OPEC price, the net back at the North Slope will go up. But it's not true from that to say the tax tariff doesn't determine the price on the North Slope. So, here you've got the OPEC price here at this level and, depending on the distance from Saudi Arabia and from the Persian Gulf, you'll have prices in various markets in the world like this - prices at the refineries. And then there will be other places that feed into these refineries, and you'll have to subtract transportation costs from the price there. This is the.... If this is the West Coast price, then the transportation cost from Prudhoe Bay to the West Coast influences the West Coast price. Now suppose Prudhoe Bay, plus California, put in more oil than the California can use - than the West Coast can use. That, in a sense, begins to free it from the OPEC price, because California is no longer importing OPEC oil. The only way that Calfornia price is determined by OPEC is - what is the transportation cost beyond California to the next market, which is the Gulf Coast, or to Japan? That is, it's the OPEC price in a third market that then begins to determine the Prudhoe price.

So, yes, it's true. OPEC moves the whole structure up and down. But what goes on on the West Coast of the United States determines whether this is wide or narrow and determines whether the West Coast price is above or below the OPEC price. I think it is inevitable, as long as there's a surplus on the West Coast, that the West Coast price, particularly for middle-sulfur, middle-gravity crude oil, like Prudhoe Bay crude oil, will be below the OPEC plus transportation. It's got to stay below that or we won't even absorb all the North Slope and California crude. The price situation can't be such that refiners are indifferent to whether they use Saudi twenty-seven degree, one percent sulfur crude or North Slope twenty-seven degree, one percent sulfur crude. So the West Coast price is going to be lower than the OPEC price for as long as we can forecast in the future.

I think that Battelle is reasonable in saying, we really don't want to forecast beyond 1985, because both supply and demand.... there are so many uncertainties in both supply and demand. The general concensus is that world oil prices are going to go down until some time in the 80's, and then they'll start

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turning up again some time in the 80's, but there's enormous disagreement about when that is. Some....the C.I.A. and Dr. Schlessinger (ph) and EXXON say 1982, there are other people who say that the crunch is like the horizon, as you get close to it it recedes because the geologists and the government officials have always, historically always, underestimated the new discoveries. The Paley (ph) Commission in 1946 had us running out of oil by 1949, the Geological Survey had us - in 1921 - running out in before 1929. That's why they set up the Naval Petroleum Reserve in Alaska, so the battleships would have some oil to run on in World War II.

Anyway, up to 1985, the West Coast price is going to be below the OPEC price - how much below the OPEC price depends on the market behavior of the producers and sellers on the West Coast, among other things. If the oil is closely held and flows through controlled channels - the North Slope oil is controlled overwhelmingly by ARCO, EXXON, and SOHIO - the effect of competition is going to be minimum. They don't have to violate anti-trust laws, they just have to behave like gentlemen toward each other. They just have to avoid getting into price wars that they know would be mutually ruinous.

The state royalty oil sold to an independent marketer has no such constraint. And, if one of the non-majors came in with a discovery out in the Western Arctic, or something like that, and it was somebody who was not tied in by intimate relationships with the (indisc.) agreement, and things like that, somebody came in with a large field - it could be Occidental, or even a major - Texaco or Gulf - they could break the market, too. Let's say that if ALPETCO attempts to move 150,000 barrels to the West Coast market, they are almost certain to break the market, and the bottom is somewhere in the vicinity of $2.00 below the present price. Now it won't hit bottom. Maybe the SOHIO pipeline will be built which would mean the bottom would be in the vicinity of $1.25 below the present price.

MR. GRUENING:

Does that mean that this is money that ALPETCO is going to lose if forced to sell it, so this is money to pay the state if, supposedly, they lose? Let's say they lost $1.00 a barrel, and it takes seventy-two months, I think in the contract, before they are actually putting it in a form where it could be sold. But, as a refined product, you're talking about over $300 million.

DR. TUSSING:

They don't lose any money. They sell it at above cost. Their cost is $11.79. When it first comes in they can sell it on

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the West Coast. The West Coast refiners are paying $12.63 for that kind of oil.

MR. GRUENING:

You're saying that they won't prolong if they get....

DR. TUSSING:

Okay. Now the question is....the contract does not compel them to refine in Alaska or to process into petrochemicals any specific amount. So they don't reach full production. In their pro forma, their financial statement, they assume that they reach full capacity of 150,000 barrels a day in the fourth quarter of 1985. There is nothing that prevents them from continuing to sell. Suppose their petrochemical production contract is slower, and suppose they are making a good deal of money on these West Coast.... There is nothing in the contract that compels them to refine all that oil.

Now, I'm not trying to predict what they are going to do, because they don't know. I'm sure if you asked them, they'd say - well, these are the projections we're working on, but we don't know what markets will be like; we haven't even got our products laid down. But I would say, in general, that the existence of a crude-based petrochemical facility benefits Alaska in terms of the tax and royalty (indisc.).

An independent marketer very much hurts Alaska. It cannot do anything but hurt the state, and the state would be much better off to say - we'll keep the oil until you go on-stream, but we'll pay the two percent margin that you expected to earn on it. Let's just give them the money and let the producers.... The state would be far better off just handing them the two percent outright.

Okay. Well, let's go on and get back to the Alaska disadvantage. You've all heard about the Alaska disadvantage. I don't need to repeat it. You've got transportation cost disadvantages, higher construction costs, higher operating costs. And virtually everybody in the business, whether it's in the oil business or the chemical business, except this group, believes the Alaska disadvantage can't be overcome without some sort of subsidy. Now this group believes that....ALPETCO believes that it can.

I haven't worked through their economic analysis, and I don't know. I just know that it's a minority point of view. It's virtually a minority of one....

UNIDENTIFIED SPEAKER:

You've been there before.

DR. TUSSING:

No, I'm not the minority. I'm with the majority. They are the minority of one. And even their marketing consultant at the Royalty Board agreed that Joe Moore's assessment of the probability of success is fifty percent, at best - agreed that that was a fair assessment. Let's say they are going against the entire weight of industry sentiment, and I won't quarrel with that. But there is an Alaska disadvantage. Now, how can it be overcome?

The marketing plan we talked about has two elements. One is the expectation of getting long-term, hell or high-water, take or bake contracts from Japanese chemical consumers - Japanese industry. I did an investigation of this for the Commissioner and found no reason whatever to believe that there was any possibility that they would accomplish that, and I would say that the odds on that part of their program are - maybe they are finite - very close to zilch. Now it is conceivable that the notion that they can market on the West Coast....there is a substantial possibility that, given their cost structure, they can market on the West Coast. There is no basic petrochemical-producing facility on the West Coast.

Given any reasonable assumptions about economic growth, the demand will increase, and there is a gap that they could fill if they could overcome the cost disadvantages of operating in Alaska. They realize that the alternative sources for the West Coast are, for example, the Gulf Coast - the expansion of the existing petrochemical industry there - and there is part of the cost disadvantage, the transportation cost disadvantage, the transportation cost component of the Alaska disadvantage, is offset by the fact that if that crude has to go to the Gulf Coast and the products come back to the West Coast. So a West Coast petrochemicals plant would have a substantial advantage for the West Coast market over the Gulf Coast. Now it's quite conceivable, even though a California-based petrochemical facility would be in better economic shape than an Alaska one, that because of air-quality problems, site problems, it may simply be impossible to get a site for a petrochemical plant in California. So given those two considerations, they might be able to offset on the West Coast a good portion of the Alaska disadvantage.

The remainder of the equation is an interesting one - that if the West Coast price for Alaska-type crudes were substantially below world market price, below the Gulf Coast price, if there were no SOHIO pipeline, if exports to Japan weren't allowed, then we'd have a price for a North Slope crew. There would be a price advantage for a West Coast producer, whether in Alaska

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or in California of a dollar more per barrel over its competition in the Gulf Coast region or, for that matter, competition on a crude- or naphtha-based facility anywhere in the world. Here's where the marketing fits in, and, again, I don't believe this is ALPETCO's game plan. But, if by marketing crude independently between now and 1985 they broke the West Coast price, pushed it down to a level $2.00 below the world market equivalent, they would have gotten their subsidy from the state. They would have gotten that $2.00 by the back door. Now, why, when they go on-stream, doesn't the price go back up again? And that's an interesting question. Would it go back up when they take the crude out of the crude market and start marketing petrochemicals. I suspect it's a one-way downward rachet, because the equilibrium price - that is - the normal situation and the absence of some sort of anti-competitive behavior, is the same for all destinations at Valdez. And that the big three would have to collude, and they'd probably have to get the California independents on board. They would have to engage in per se violations of the anti-trust laws to re-establish the differential price structure. I think that once this differential price structure is knocked down by competition it would take a positive intervention - anti-competitive intervention - for the market to restore. So....

UNIDENTIFIED SPEAKER:

Dr. Tussing, just a moment. If we're talking about a time-frame of 1984-85, which is to unscrew their oil from the West Coast market, this is the time when the shortages, or the surpluses, appear to be diminishing. And if we further diminish it by 150,000, which is hypothetically injected into that under your scenario, doesn't that have to drive the price back up?

DR. TUSSING:

Well, as long as there's a surplus, there is no force driving the price back up; that is, there's a surplus now that is having downward pressure on the price. And that downward pressure is being resisted by the fact that the oil is moving in controlled channels. So long as the surplus exists, I don't think there can be any upward pressure on the price on a price structure that's been established previously by competition.

Secondly, I don't think we can count on, say, 1985 being the time in which the surplus is diminished. All we can do is say with confidence that the surplus will increase until 1985. After 1985 we don't know whether it will level off or diminish or what. So the.... I'm not trying to forecast the future.

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I'm just.... The case I've established, with respect to the erosion of the price, is a worse case. As I said, I think there is a substantial possibility there will be some export outlet. For example, they could....the Federal Government could go half-way on it by allowing the export of residual oil from the West Coast. And it's the heavy high-sulfur resid which is creating a good deal of the glut. The top-end of the barrel can be used. If the California refiners could export their heavy fuel oil to the Far East, that would take a lot of.... There are things that would minimize the danger of the scenario, but the point I want to make is that the scenario which is worst for the state is best for ALPETCO in the sense that the best way of overcoming the Alaska disadvantage is with a lower price for crude. And that is one way I can see, without going dollar per dollar through their cost projections, and I'm not a chemical engineer or a cost engineer, and I can't assign costs to the various elements of their proposal, but just in broad general terms to overcome this cost differential, this is the only way I can see it working on the West Coast is they are relying on a West Coast price that's lower than the import equivalent price. And that is a way of overcoming the disadvantage. I want to repeat - I don't think that this is their game plan, because I've seen no evidence that there's been any long-term or any sophisticated view of the crude oil market on the part of their proponents. They certainly haven't put it on the record. And conversations with the participants over some time haven't betrayed any indication that this is what they are looking at. But I think that it is something the state really ought to take into consideration.

Now, if you have any more questions, I want to first ask how long you want to go.

UNIDENTIFIED SPEAKER:

I think we should just keep going.

DR. TUSSING:

Okay. One of the issues that was raised to me is....

UNIDENTIFIED SPEAKER:

Doctor, would you like to take a five-minute break?

DR. TUSSING:

Yes.

(FIVE-MINUTE BREAK)

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DR. TUSSING:

I think the most important of the remaining questions is.... two of them that go together - is it possible or likely ALPETCO could get its project financed without overwhelming assurance of its commercial feasibility? And I address this one, in particular, because I think there has been an assumption all along, and certainly Commissioner Leresche stated this, that the ability to finance the project is a good test of its commercial viability and, although we of the state can't make a really accurate assessment of it, the financial community will, and their ability to put the financing together is probably the best test of its commercial viability. I would think that would be the conventional wisdom, and I address the problem only because Milton Lipton said to you that it was not necessary to demonstrate overwhelming likelihood of commercial feasibility in order to get the thing financed. But it is quite conceivable the thing could get financed and still go belly-up. I don't think he was talking about the fact that bankers and underwriters sometimes make bad judgment, but I think he was saying that it's not necessary to show that it would be profitable to get the....to obtain long-term debt. And this is true with certain assumptions about financing, with what we call conventional financing, where there's a big equity component.

The financial markets, the bond underwriters, and the insurance companies, and the other institutional investors are not interested in the profitability of the project, per se. They could care less about the health of the equity of the owners. The health of the owners....the financial health of the owners concerns them only to the extent it affects the ability of the enterprise to pay interest and to re-pay the debt.

So, in conventional financing, if there is a sufficient equity component - that is, if the owners put up enough of their own capital - it's quite possible for them to get financing. In the worst case their cash flow is going to be sufficient to cover debt service. Suppose we're going fifty percent equity and fifty percent debt - I'll just use round numbers and not say....and I'm not going to claim these are the numbers of the ALPETCO project, but just to show the principle. Suppose you have a one-billion-dollar facility. So it's $500 million debt borrowed money. And the owner has put up $500 million in equity. Suppose the interest is nine percent, so it's got to pay $45 million here in interest. And it's got to pay.... Suppose it's got twenty-year life, and so it's got to pay $25 million a year in depreciation - in amortization - in debt repayment. All right, so you've got a total of $70 million that this company has to come up with in addition to its operating costs to pay off the debt. Now, to make money, to make it a worthwhile investment for the equity investors, they

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probably have to make fifteen or, say, twenty percent before taxes, at least. So it's probably twenty-five percent before taxes. So, to make it profitable, to make it worth doing, they have to come up with a cash flow of $195 million a year; that is, in profits, allowance for interest, and depreciation they have to come up with $195 million a year.

The equity investors probably won't go in unless they think they can make $195 million a year. They won't start the plant unless it shows on their pro forma statement that the cash flow is going to be $195 million. The bond sellers will go in, and they really have to be convinced that there is for sure going to be $70 million. And, if the $70 million is there, the owners could be losing money every year and they are still meeting their debt obligation. So it's true that a non-profitable....that the financial community is willing to invest in projects which may turn out....which have a good possibility of turning out not to be profitable and of pouring in money and lending money to PAN AM, or Penn Central, or God knows what. All sort of Chrysler companies lose money year after year after year after year. So long as there is some security, and they'll look at it in terms of the debt service coverage. They'll say.... They'll project the income and say the cash flow is how much percent of the debt service. Now, in evaluating utility bonds you look at what is their income as a multiple of the amount of interest and repayment they have to pay.

CHAIRMAN MILES:

Dr. Tussing, the equity owners aren't going to sit by and let that happen year after year after year.

DR. TUSSING:

What can they do? What can they do? They, most likely, have a situation, and this is true of many of these companies, this is true of Chrysler, for example, where they lose money year after year. They lose more by shutting down than they do by continuing to operate. They have to.... If they shut down they still have to pay that $70 million debt service. They still have those fixed costs.

If their revenues exceed their operating costs by even a penny, it pays to minimize your losses. And so, generally, when a facility is worth more as a going business, even to the trustees in bankruptcy.... Well, let's look at some numbers here. Suppose the fixed costs are $250 million a year and the variable costs, that is operating costs, are $250 million, so the total cost is $500 million. Okay, now....suppose your revenues, that is the sales, are $400 million with a loss of $100 million. What happens if you shut the plant down? You do away with

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$250 million operating costs. You reduce your costs by $250 million. You reduce your sales by $400 million. And so your loss goes from $100 million to $250 million. So what happens is these fixed costs include payments to bond holders, and so on, creditors. The same when you get the drain of $100 year after year and pretty soon the equity of owners is wiped out. And suppose they get to the point where they can't meet their....they can't pay their operating costs? The thing goes into bankruptcy. The bond holders become the owners. And they see this enterprise can't pay $250 million any more. What can it pay with sales of $400 million? All it can pay $150 million in interest and repayment. So, they take a bath on that, put the thing up for bid, and somebody buys it at a price which reflects this situation. That is, the old owners are wiped out, somebody comes in with a lower capitalization - he comes in owing less money - so he has to pay only this much.

First, in answer to the first question. With conventional financing it is possible to finance a project that has a large risk of losing money. And conventional financing is one where the owners either put up a substantial amount of equity or where this is a subsidiary corporation where the parent corporation, or somebody, is willing to guarantee the debt. So, to the first question....yes, with conventional financing where there's a substantial equity cushion, where even if the owners are losing money year after year, there's enough surplus revenue to pay the debt service. Yes, you can.

Second, in that sort of situation, the company can go on losing money for years and years and, as long as the owners, or the creditors, or the trustees in bankruptcy, or a potential other owner see that its sales are going to be more than its operating costs, it will continue operating. Now the owners may lose everything they've got, but it will continue operating. So, let's look at some of the consequences of this situation.

Suppose ALPETCO does get its financing together. Now, let's pass, for the time, on how they can do it, because they aren't proposing conventional financing. Suppose they do get the financing together and then they start losing money. Does that mean it's going to shut down....the plant is going to shut down and throw out the people who are working for it? Does it mean it can't pay its operating costs, which include the cost of feedstock, any more. No. Not so long as the sales exceed the operating costs. And in a capital-intensive operation of this sort, you really have to get into a bad situation before it pays to shut down or dump the plant before its value as scrapped is greater than its value as a going concern. So the chances of the state being compelled, from the point of view of keeping the jobs flowing, of bailing out a conventionally financed plant, are minimum.

I think the problem with ALPETCO is that its proposal is a little different. It proposes, rather than conventional financing, what is called project financing where the companies that own ALPETCO are putting up any their own faith in credit. They are not proposing to support the thing. So the bond holders have no recourse against Alaska interest. They can't take Anchorage Natural Gas; they have no recourse. They can't put a lien on Sea Train's ships, they can't put a lien on a native corporation's lands or future income, or anything of that sort. So, their only recourse is against the project itself. So they are going to look with even greater scrutiny than they would at the income statement and whether there is enough income to cover the debt service. Again, the problem here is that the owners don't propose to put up any capital. They propose one-hundred percent debt financing, or, if I read it correctly, there is something like a hundred....seven percent financing. When the thing goes on-stream the facility will have a negative net worth. That is, they will owe more than the plant is worth. And so the only security....the thing that they have to do, since there is no security in terms of an equity cushion, say all the cash flow has to be available for debt repayment - there is no equity cushion - they're not taking any bath, there's no recourse against the owners. Then what is absolutely essential is there be somebody that they can have recourse against. Well, I've convinced the Commissioner and his staff of adequately protecting the state against any legal recourse against the state, or against its revenues, or its royalty oil.

The only other alternative is that the sponsors get these take-or-pay, these iron-clad, hell-or-high water contracts where they have contracts with credit with the purchasers; that is, major chemical companies whose contracts are bankable. And these contracts may not have a fixed price, but they assure that have a....called hell-or-high water, or it's like the (indisc.) tariff we were talking about last year with respect to the gas pipeline where the purchasers have to promise, have to contract, to put up enough money, regardless of whether the plant is on-stream, whether it's producing, whether the producers are able to re-market the product to cover the debt service. Now it may be a formula price for the final price is determined by the world market price, or an index, or something like that. But there is no way that you are going to get institutional investors to go a hundred percent, or even seventy-five percent debt. In project financing, again, there's no recourse against the owners. Project financing....there's no way that the institutional investors will do that unless there are contracts that will provide for an assured revenue stream equal to the debt service charge - to the interest and amortization.

So, I'd say I don't know what Milton Lipton, what the assump-

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tion of the questions to him, but I would say that the conventional wisdom is more right in this case; that is, that unless they can show the (indisc. - cough) that they've got contracts to sell the stuff, and contracts that are enforceable against credit-worthy purchases, then they are not going to be able to put it together. And I think that's what they've been saying....that ALPETCO's been saying all along. And their ability to finance the project is a measure of viability. If, for example, as against the conventional wisdom in the oil and chemical industry, and practically everybody I've talked to, going against that they are able to execute hell-or-high water contracts for the sale of their product, they will be financed. And they've got no marketability problem. They will be profitable because they have no equity to.... their rate of return on equity will be infinite regardless of how much money they make. So, if they can get it financed, they'll get it financed according to the plan here. If it's going to be project-financed a hundred percent debt, the only way they can do it with hell-or-high water contracts for most of their proposed output, and, if they've got that, they are home-free. They're not going to come back to the state and ask for special deals.

MR. PARR:

Dr. Tussing, what you are saying is if they have assured sale contracts....

DR. TUSSING:

Yes....

MR. PARR:

....they have an assured supply of raw material feedstock from the state, and they've got a physical plant, the bond holders aren't risking very much.

DR. TUSSING:

That's right. Well, they don't even have to have a physical plant. I think that they have to have the kind of hell-or-high water contract that as of such and such a date the purchasers will pay as if they were receiving the product even if they aren't. This is like (indisc.) Gas was proposing and El Paso was proposing for the pipeline financing; that the customers would start paying for the project and would start paying off the bond holders even if the thing were never finished. Say, they don't need the plant but they shouldn't have trouble getting the plant. They could run into cost overruns. That's a danger. And there are lots of scenarios in which I'd insist in coming back to the state for assistance

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And, if it were conventionally financed, the risks on the state would be minimal because that equity cushion would allow them to operate at a book loss for years and years without laying off employees or without needing to have a discount from the state.

I just don't see where they are going to get these contracts. And practically nobody I've talked to, except those associated with the project, think that they can do it. But I think the argument, and the approach of the administration, is what harm does it do to give them the chance? To give them a hunting license to go out and look for those contracts. If they can get the contracts, if they can get the financing, the state is ahead. If they can't, all we've lost is the time and the effort of the state officials and the Legislature in going over it.

MR. PARR:

Dr. Tussing, you said a minute ago that with conventional financing the state didn't have anything to worry about. By implication, one could assume that on this project financing we do. But, in actual fact, if isn't making it, the bond holders would take over to keep the operation running to get their money back. Isn't that correct?

DR. TUSSING:

Well, that's the most likely.

MR. PARR:

In other words, I'm thinking in terms of the loss of jobs and so forth and the dangers of (indisc.).

DR. TUSSING:

I don't want to say there is no danger of loss of jobs, because it is conceivable if we move into the middle 1980's with a big world surplus of petrochemical-producing facilities everybody else is going to be looking at operating costs, and we're going to have new plants on-stream in Saudi Arabia where they can back down the feedstock costs, where the Saudi government owns fifty percent of it. And, in order to minimize their losses, they're willing to cut back on the feedstock cost to cost of production, which may be forty cents per million B.T.U. or something like that. So, in that situation, you've got two things. Who's got the lowest operating costs, and this plant will certainly not have the lowest operating costs worldwide, and who's got the contractual market to share? Again, if the purchasers go on for twenty-year contracts, hell-or-high water, and the purchasers are credit worthy, they are

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the biggest chemical companies in the United States or Japan, or wherever, then you really can't ask for better security and the dangers are normal commercial risks. I don't think there's any exceptional danger in it.

Now, on the other hand, let's look at some of the things that are likely to happen if they run into problems, if this group does not make its schedule. It's not going to roll over and play dead and say that well, sorry, that's the way.... you lose some....you lose a few, you win a few.

The first thing they're going to do, and they are going to do it whether they get into trouble or not, is they are going to go to municipalities or to the state and ask for industrial development bonds to finance their terminal facilities. It's ridiculous not to, because you can get a tax-free rate on.... and the City of Valdez did it with the terminal there.... And they can go to the City of Noorvik (ph), for that matter. It needn't be the City of Valdez, it needn't be where the terminal is, to get Noorvik (ph) to issue industrial development bonds rather than bonds which will be evaluated on the basis of the project. And they'll sell them the tax-free market. The City of Noorvik (ph) will get a fifty-thousand-dollar commission, or something like that. And, so, that's the first type of aid. Well, it seems to be costless unless the project goes belly-up. Unless it can't meet the bond obligation, the state has no legal obligation to come to the rescue of that, and it's just that Noorvik (ph) will never be able to sell any bonds again in the future, and the state will feel a moral obligation because if Noorvik (ph) defaults on $350 million dollars of industrial development bonds, it's going to affect the state's rate.

So, they're going to ask for that, and they're going to get it. They're going to find some jurisdiction in the state who will take the fifty thousand dollars. There's no question. And there's a certain amount of risk. For Noorvik (ph) if it couldn't be a better deal, or whatever, it couldn't be a better deal. They will ask for that, and they will get it. So, that's the first additional aid, and they are going to get that whether they get in trouble or not. There is no question in my mind they will.... I don't know - have you started talking to people about industrial development bonds?

CHAIRMAN MILES:

Anyone want to comment on that?

DR. TUSSING:

Well, maybe that's unfair....

CHAIRMAN MILES:

Yeah, I'd prefer to comment on all your (indisc.).

DR. TUSSING:

I don't know that they have, but they'll start soon enough.

What other assistance? Suppose they're just a tad from getting the financing together. They've got eighty-five percent of it. and you're going to be here like the Northwest Alaska pipeline. We need the back-stopping to put us over. After all, we have demonstrated that the benefits to the state are enormous. And, look, they are paying 10.9 percent interest on this last bit. The earnings on the permanent fund portfolio is 8.3 percent, something like that. If the state buys their bonds at 9 percent, or markets their bonds, or guarantees 15 percent of them for a commission, how can you lose?

Otherwise, we're going to lose this multi-billion-dollar project and all of these four-hundred, or four-thousand, jobs. And so, it's an offer that's very, very hard to resist. It doesn't require.... If it's the permanent fund, the permanent fund managers look at this as a straight commercial decision. It meets the constitutional requirements for the permanent fund investments, and it will probably meet the statutory requirements. And it can be done without a vote of the Legislature and a vote of the people, unless the Legislature wants to say that no single investment of the permanent fund for certain.... But, that's the next thing.

Now, suppose the facility gets financed and gets into trouble. We have the same kind of thing. I'm not saying these are going to happen, but, you understand, the owners with their commitments are not going to, at some point, say well, we haven't made the schedule, or we haven't made the financing, or that's the way the ball bounces, or we're losing a million dollars a year - that's the way the ball bounces. And, so politically, they've signed a loyalty oath they're not going to ask for a reduction in the well head price, and there are certain moral commitments on the part of the state government to the people that they are not going to do it. So, how about re-financing? How about re-financing the thing? We're paying 10.9 percent. We can show....our pro forma shows that we'll break even. Otherwise we are going to be in bankruptcy and we're going to shut down, and so on. Would you....would the permanent fund re-finance our debt? Well, at that point we've bought the whole package and it's all sort of a re-finance (indisc.). This has happened time and again, not with these people, but with local industrial facilities. And I think if you haven't read the history of the (indisc.) Refinery in

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Newfoundland, there are some very disruptive....terrible. So, again, I don't know whether these risks are excessive. I haven't calculated the benefit to the state of this project. And if it went through, if the ALPETCO people's optimism is justified, the benefits would be significant. I don't deny that, and I don't condemn them for wanting to draw to an inside straight when the ante is so low in the pot and the pot is so big. But these are things you've got to consider.

One remark that might be a concluding one in this respect - what the significance of the whole project is. I believe that the Administration, that the Governor and Commissioner, have tried to give Alaska what the polls, and what the Alaska Forum, and what the Legislature has indicated the people want. That is, we want a petrochemical plant, but we don't want to pay for it.

All the assembled industrial wisdom, all the big oil companies, the big chemical companies, and all our consultants say they can't do it. It can't be done. Here you've got one company, one group of people, who says it can be done. So, why not give them a chance? That's fundamentally what the Administration's logic is. And, if you buy that logic, I think it's nit-picking to talk about the question of pledging undiscovered oil or the option on the rest of the royalty oil. We have nothing to give. All we have to give them is high costs, a horrible logistical place from the point of view of transportation costs - that's high labor costs, high construction costs, a god-awful climate that makes it harder to operate these things, and we've got some oil an assured supply of which is worth nothing now; that is, there is no premium for an assured supply. And these people are willing to come in.... I'm sorry they left, because (indisc. - laughter). They're willing to come in and gamble more time and money than the state has putting together this....I think it's pie-in-the-sky. They're willing to take a chance, and the Governor is saying to you well, what harm is it?

It is not true that it is a riskless contract. It's not true that it's a perfect contract given all things. But since we're unwilling to give them anything on outright, they're going to get every little fringe benefit they can. Nobody else has ever thought of the state furnishing them fill for the pipeline and the bottoms of the tanks. Well, we'll give them that. We'll give them the right to veto any other project we intend to use royalty oil for. But we read the fine print and we take it back, because it's on the same terms and conditions as the others. But we've given them a lot of things that seem like gold-plating. But, after all, we're not giving them anything else, and they've got all the odds against them.

So, if you want a petrochemical for cheap, for nothing, you probably won't get it with this contract. You probably won't get a better contract that's going to give you one. You've got a chance at it. As I said, I think the....giving them the right to sell royalty oil in advance of building a plant is dangerous. It's particularly dangerous, if, as is likely, the state's position on the value of oil is not upheld - the (indisc.) formula in the back of the contract does not prevail. Because the spread among prices is going to be greater.

But, other than that, and say you want something for nothing, you get what you pay for.

CHAIRMAN MILES:

Dr. Tussing, your most recent remarks seem to discount the fact....or discount it as being important the fact of an assured supply. We've heard quite contrary testimony to that. Could you go through your reasoning again on that?

DR. TUSSING:

Right now, and at least for the next five to eight years, there is a buyer's market in crude oil world-wide. There is an enormous surplus of crude oil-producing capacity. But right now nobody will pay a premium for an assured supply. A long-term contract is worth less than a short-term contract, because a long-term contract pins the buyer down to a single source of supply when it's in his advantage to shop around in this market. Now what the other people have been saying is that sometime in the future the world crude oil demand is going to overtake producing capacity, and supplies will get tight. And, as a hedge against that time, a supply contract going out in the future may have some premium value.

Now, the present does reflect future expectations, but people give lip service to the value of an assured supply in the future but they're not willing to pay anything for it. And, again, that tells you whether they're really serious or not. You can....nobody will pay premium over the OPEC price to any of the OPEC countries in exchange for a secure supply. And, in fact, the OPEC countries have to accept a discount against the price to get a guaranteed long-term off-taker.

CHAIRMAN MILES:

Under that line of reasoning, though, it would seem that what you're saying is that it may be wise to delay this decision until the surplus is reduced or the shortage is intensified, however you might want to term it.

DR. TUSSING:

Well, the surplus may increase and the price go down. The thing is that ALPETCO is guaranteed against that if the price goes down with everybody elses. So you're not taking advantage.

Two years ago....three years ago people were panicked and they still remember the embargo, and you probably could have gotten a premium for a long-term supply, and you probably could have gotten.... In fact, I think the Alaska Petroleum Company, the Coastal State subsidiary, was willing to offer....two years ago was willing to offer a premium for a long-term supply contract. And a premium over the in-value price, and that reflected the perceptions then. Now there's still some hangover from the embargo, but it seems to me that what people are legitimately concerned about in the future is, not reliability of supply, but price. That is, as virtually nobody anticipates another embargo for a whole series of reasons, even when the supply gets tight again. By that time all the OPEC countries will have been so co-opted into the world capital system they will such enormous domestic import demand, they will be so integrally tied in with the Western financial system that they just wouldn't....that it's almost out of the question they'd participate in something like that. There are a whole number of reasons why what people are concerned about is if the price turns up again. And, unless you give a fixed price contract.... I don't even know whether you could get somebody to pay a premium for a fixed price contract, because the world oil prices are going down now. And virtually nobody expects them to go up faster than inflation until.... for the next five years, at minimum. The question is - when does it turn up? And that depends on a lot of things that we can't predict.

Now the ALPETCO group is operating on the premise that there are chemical purchasers, particularly in Japan, that will offer a premium for an assured supply of petrochemicals. I think they're a minority of one in that respect. They may be right, but none of the major chemical companies and none of the major oil companies believe. And they're going to have to beat their way into a market which is pretty much tied up by the majors already and in competition with a great number of new petrochemical facilities that are going in in OPEC countries and in third-world countries that want to have them for just the same reasons Alaska does. They want them for diversification of their economies, they want to create jobs, they want it as a symbol of national prestige, and in every case that I've looked at they are willing to subsidize. So they're willing to take a substantial amount of the risk. In Saudi Arabia, Saudi enterprises are taking fifty percent of the thing.

In Korea, which is has no feedstock advantage, the Korean government is undertaking to back-stop them on any operating losses. In Singapore, again, there seems to be....the government seems to be willing to share the risk. In Iran the government is contributing the feedstocks as its equity. And so, then, if there's a ....they are in a position to do so. So we're looking at competition in the world market with a lot of jurisdictions where they're willing to offer something more than Alaska is to beat their way into the market. And there's a large ethylene-producing surplus in the world today. All the projections show that it will be greater in 1980 than it is today. Now that that surplus would be worked off in 1985 if we have normal rates of growth and if no new facilities are planned in other countries between now and then.

So, I don't know whether it pays to.... If these people will take the crude, and if they can get these hell-or-high water contracts, and get the thing financed, this may be the last chance. Now, if they tell you it's the last chance, that means they know they're in a sliding market. If they told you you'd better do it now or you'll never be able to do it again, they would suggest they have the conventional view of the wisdom of the project and that they'd better convince the bankers before the bankers know what's really happening to the market. too. But, as I say, it's....I don't know....

MR. PARR:

Let me ask you.... One of the previous witnesses of the day, I made this statement and the answer was yes. About the time this project should go on-line in 1983 you'll have a seller's market. Now, you just referred to a buyer's market. And the answer was yes. This was another one of the expert witnesses. Do you disagree with that, or are you agreed?

DR. TUSSING:

No, I would say that is the earliest possible....and I suspect it will be much later than that.

MR. PARR:

Well, that's when the facility goes on line?

DR. TUSSING:

Okay. Okay. But the state's not getting any premium for this oil. If it was going to be a buyer's market in 1983, a seller's market in 1983, in which security of supply becomes important, then your conclusion would.... If that's the case, then the state would do better not to sell its oil under terms now that

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it gets only the in-value price.

MR. PARR:

That leads to my second point, then. You said that oil prices are going down. I'm not an economist, but I understood that we were using more oil than is being produced - supply and demand should be driving the oil prices up, not this year and I don't say next year, but isn't the long-range thing that involve prices like everything else be going up?

DR. TUSSING:

Well....

MR. PARR:

....and the more that the demand outstrips the supply, the more they'll go up?

DR. TUSSING:

Well, demand is not outstripping supply now.

MR. PARR:

This year, this year.

DR. TUSSING:

This year or next year. So, until the mid-80's, sometime in the mid-80's at the earliest, the pressures on world oil prices will be down. I think there's pretty general agreement that until 1982 or 1983 there are not going to be any increases in the world price of oil above the rate of general inflation.

How long after that it goes you get the C.I.A. saying 1983, and you get the U.N. saying 2,000, and there are other people who say that it's like the horizon - the closer you get to it, it withdraws. Say, if you get out past 1990, not only are the.... there may be large developments of conventional oil but, if these high prices maintain all that time, we end up re-defining petroleum, or changing our definition of petroleum.

There are three deposits of heavy hydro-carbons in the Western Hemisphere that I can name, and there may be others, each of which have more oil in them than all the conventional crude reserves of conventional oil in the world. Any one of them - they're all in the vicinity of a trillion barrels of crude reserves - the (indisc.) tar sands, the Colorado oil shales, the Orinoco (ph) tar belt in Venezuela. Those have not been economic resources in the past because it's always been far cheaper to produce or purchase....

/Whereupon the tape recorder apparently ran out of tape/

I don't see anything the state gains by selling now on a long-term contract at the in-value price, because they are going to get that anyway. In terms of selling, the state is not getting any premium for the long-term sale. The state may get a petrochemical plant. I personally doubt it, but it may get a petrochemical plant. Now, if it wants it, it's got to take some risks. Any enterprise that comes in, whether it uses state royalty oil or anything else, is going to ask to be bailed out if it gets into trouble. If ALPETCO went to SOHIO....incidentally, if SOHIO's oil is cheaper than in-value price, SOHIO's really got a problem. Ask them why they don't try to buy it from SOHIO. Well, because of the political involvement of the state it has a symbolic value, and the state selling its royalty oil may.... SOHIO probably just doesn't believe that the thing's got any potential and won't be involved in it, but they would do better going to.... Suppose they did go to SOHIO and got the oil and got a jump. If they got in trouble they'd still come to the state, whether it's the state royalty oil or not. If they couldn't meet the debt service, they would come to the permanent fund and ask for re-financing. Here this project for, what is it, four-thousand jobs, and they had that last fifteen percent of financing to put together, and they were buying SOHIO's oil, of course they'd come. Or, if you've got a big bottom-. fish processing plant, they've evidently got no objections to the state taking some of the risks and providing capital subsidies for bottom fisheries. So, what's so sacred about something that uses the royalty oil? Every business is going to have to be bailed out, and we're going to have the pot full of money to bail them out with. The risks to the state on ALPETCO aren't that much worse than the risks on anything else.

Let me wind up with one thing....with one suggestion to the Committee. One of my terms of reference here was how the Legislature does resolve the actual legal, analytical policy questions presented by the contract. When I was working in U. S. Senate in the Energy Committee, the Interior Committee, we had a procedure for hearings of this sort in which the staff would make up a long series of written interrogatories organized into the factual questions, the statistical back-ground, things like that, legal questions, analytical questions, and things like projection of future trends and how things work, and policy questions. And these could run....sometimes there would be four or five questions, sometimes there would be four or five pages of questions, and the witnesses, govern-mental witnesses or the industry witnesses, would be sent these over the signature of the Chairman some weeks in advance, or

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far enough in advance of the hearing as was practical. At the same time the hearing was scheduled the interrogatories would be published along with the official notice of the hearing. Then the witness would be required to bring a prepared statement responsive to these things and to deliver it to the Committee twenty-four hours before they appeared.... before the witness appeared. So, again, the members of the staff would have a chance to look at it, because a lot of the questions revolved around very difficult legal points or complex statistical and analytical problems that you really can't cope with just off the top of your head, and which the witness can't cope with off the top of his head. At the same time you get the witness on the record as to what he means and it's very difficult for him to back out or change his premise.

Now, this would be particularly useful with this contract where there is some....the question, what does the contract mean. Section 2.3 has the phrase....ALPETCO can exercise its option to purchase as under circumstances which are triggered by a proposal to offer the oil for sale to another purchaser at a lower price. Well, what is proposed to be offered mean? Does that mean the Commissioner has simply asked for proposals? Now, some people say we need a fancy legal expert to do this. You don't need a fancy legal expert to find out what that means. Because, if the thing gets to court, if it's ever going to be litigated, if it gets to court, what does the judge want to know? The judge wants to know what is the intention. What did the contracting parties intend by this? He doesn't go to his legal dictionary and look up propose to be awkward. He goes to the men of the Royalty Board or he takes testimony from the two parties as to what was said in negotiations, and they present whatever they can. And, so, if you ask the question, if you have a series of interrogatories and say, what does this mean - does it mean that such and such? - and you ask both the Administration and ALPETCO to answer it, either they get together on the answer, which is perfectly proper, in which case they give you an answer, and you know what that means. Henceforth, that is what it means. Because if anybody questions it, the other side just goes into court and say before the Joint Committee of State Legislature they say their understanding of it was this. So, that's what it means. If they come up with different answers, and it's a serious thing, you've got to reject the contract because you can't ratify a contract when the two contracting parties don't agree on its meaning.

This list of questions prepared by Legislative Affairs, questions to be answered in these hearings, is exactly the kind of thing you've got in mind. They've got to be sharpened, but there are some very good questions in there that are going to fall between the cracks in this hearing. Or, for instance,

Fred (indisc.) will tell the Chairman the answer to one of them. But he's not on a public record in such a way that you've also asked ALPETCO the same question, or, if it's a question having to do with what's going to happen under what circumstances where you've asked the consultants to respond to the same thing on the record where you can compare their answers. And I would strongly suggest that you get your Committee staff, or Legislative Affairs, to put together a series of questions of this sort which can be directed, above all, to the two sides that are contracting this but, also, to the extent they're appropriate, can be directed to the consultants. And you can ask the consultants, to within their particular competence, to respond to these vario) questions.

CHAIRMAN MILES:

Are there any questions for Dr. Tussing?

Thank you very much. It was exciting and enlightening.

AGO 545657

Saturday 3/18/78

Tel conferencing

① Take testimony from witnesses in Juneau

② One witness from witness in Anch, Fbks, None

- Rice + Brennan's testimony (Trustees of Alaska) in the record
- Tossing to Royalty Board testimony

Hovig –
Risk involved and
Rewards
Subsidies

Subsidies
Reduced Price
70% Prov.
90% Prov.

Risks (+ Rewards)
Near term Risks
1. Flood CA with crude oil (Freezing)

AGO 545658 +

Scenario remote

2. Unable to put project together with 18 mos.

Near Term Rewards

1. Employment
2. Construction

Long Term Risks

1. Plant built & running
   Then ALPETCO can keep it operating profitable
   Risk accrues to ALPETCO
   Risk is minimal for ALPETCO to get financing.

Rewards

Jobs
Construction
Investment
Profits of Endowment Trust

All we want is "the opportunity to try"

AGO 545659

Miles: Subsidy Question:
- Line file requirements 9 MM
- Price Change/Reduction

Honig: - Could be viewed as a subsidy. However, more "an investment" than subsidy. Not a lot of money relative to the total contract

- Joe's insistence. - A strength rather than weakness

Miles: Nevertheless, the reduction is a real possibility

Chatterton: At what time can ALPET 6 take the interim crude 10.2(d) and
Financing Question:
Not just capability to borrow the 1.5 bln but a commitment.

AGO 545660

Miles: Cost of facility

Hovig: Rough estimate 2.5 billion
incl off site
dock
utility

Miles: Why is it not mentioned
in the contract?

Hovig: 1. Facility must be
"placed in" —
2. adm. wanted the
benchmarks so they
are attainable — so
they don't have
to come back
to Cong. — hope to
do better

Before it's over we will
probably spend more
than 2.5 bln.

Clotfelter: Article 13 — Brokerage Clause
anything over 30 M can
be disposed of at
ALPETCO's discretion

Honig: Pg 21 of Presentation – "Core" Refinery includes feeding the aromatics Plants + Feed Separation Plant. It will have to serve more than the 30 M/ bbls.

Brokering of crude oil for ACS benefit – that's the main reason for the interim oil

Miller: What can you do that Alyeska did not do to assure max AK employment.

Honig: ① 34,000 reasons – the natives in this venture.

② Facility in one place instead of being strung out. People on construction will wind up as permanent employment (86% of new employees required for enlargement of Collier where Alaskans).

AGO 545662

Testimony

FOHs — 2

None —

Anc — 1

FOHs: Witnesses

① Dr Wm. Wood — Former U of A Pres.
applaud the proposal
ALPETO proposal for people
of Alaska.
Jobs —

② Mr Terry ~~Rankin~~ Pelczar
Public Input by public during
negotiations
2.2 } to be included in NPR
2.4 }
4.2 } Commitment to 2.5 Bbbl
4.3 }
2.2.2 add infinitum
4.4 Endowment — future
5, 6, 7, 8, 9 } ALPETO Capitalizing at
13 } Alaska's expense

10.3
25.2

AGO 545663

anchorage:
Jerry McCutcheon

* — Contract still under neg. as ~~early~~ late as early this week
— Legal — prior finding
— dedicating future reserves.

Issues not addressed by Royalty Bd.

— Neg. other than at arm's length
— Reduction prov. — ALPETCO surely will go for reduction
— As much money should be spent to defeat reduction as for reduction
— If contract were reneg. larger and more assured bidders would emerge
— What's the hurry — Scoog asking for delay for 2 year.
— Fin. letters of commitments — totally meaningless — must be ironclad!!
— CA flooding with high sulphur crude — reopening the trade option — who would get the profits?

AGO 545664

Dozier & Daugherty report not the final report — certain sections will be strengthened

advise Mike Miller

—

Contract still under neg.
Reliable source at the RB hearing yesterday
Call the adm. and ask them!

Henry Pratt —
— No scare tactics have been used so far
— Participation has been high
— Legislature can be first to have the honor ~~of~~ to lay the base for industrial development.

Chatterton: The mtgs with ALPETCO members and gov in Fbks and Anc — Pls check if question of contract modification was raised. Honig said — not this knowledge.

AGO 545665

3/20/78

Questions to ask ALPETCO people

(1) Barbour Oil
- Current production ?
- Pricing tier ?
- Location of production ?

Battelle

Rogers: Not available. Unknown. John Barbour transferred all interest in his bases to his father the day before he left for Japan. Rogers believes that none of the bases are producing.

(2) Pride Refinery (Subsidiary of Seatrain)
- Current production? 36,500 b/d (July)
- Pricing tier?
- Location of production? via pipeline from Texas >

Battelle

Brown + Root (contact Gary Montgomery - Houston) would probably be able to provide information. Kathy Chandler to have Montgomery get in touch with me or get his no. for me!

(3) Export of products to Japan.
Battelle (Raised by Mark C of Battelle - the "unlikelihood" that it would be permitted).

Rogers: Bill VanNess opinion — Will send copy — also products which can be exported listed in CCH Export Reporter (ask Bob Maynard)

(4) Has contract been physically been signed?

Rogers: Yes

(5) 5.3 Where is the storage? North Slope? North Slope + Valdez?

Rogers: Unclear

Kathy Chandler
Eddy Rogers - Hank Pratt 3/20/78

Rep: McK

Mallister - Not affiliated with ALPETCO

Mills: Where in contract that ISOM has to be processed

R: No requirement

McK: If refinery would only use 120,000 b/d, would we be obligated to furnish 150,000

R: Yes, but would probably not call on it unless needed for storage. Unlikely that they will ever take interim oil

Mills: 90% option - Reaffirmed earlier testimony that their concern is that a lower price would "destroy a competitive price"

R - will be able to get cheaper oil by virtue of lesser transportation charges

Key → Crown "lower adjusted price"

- all conditions attached to a sale would apply (refinery on Home Spit)

AGO 545668

Chatterton: Where can you show me in the contract that the ~~contract and~~ petrochemical plant has to be built without ~~you~~ breaking the terms of the contract.

Chat's scenario
- 30 M b/d refinery capacity
- Letter of credit
- 30 M b/d processed
- 120 M shipped south

R 10.2

Randy B: What does "commit to expend etc" mean in this context?

R obligatory (tape 1810 F)

R 10.2 not considered a breach or default

Chatterton: If you do not meet benchmarks in 10.2 we can terminate - unequivocally?

R Yes - In addition State can cancel under 4.2 if petrochemical facility has not been built.

AGO 545669

Concessions

Miles: ① Where did LeResche not give

90 % - 85 + 5 ? %

90 - 90

90 - 70

② Point of Delivery Point

Valdez vs. P.S. #1

③ Charitable Foundation

4.4 definitional problem

affiliates

↓

(?) 8.2 - in-kind vs in-value

Costs to ALPETCO

Miles: Article 12 - Commitment? To what extent?

Letter of Credit - Funds up to amts promised, issued by bank.

blank check up to the face amt of value.

AGO 545670

Thursday 3/23/78

Administration
Barnes + Bob Maynard

— Purchaser – Supplier Relationship Provision

— Whereas Clauses

— "Indirect beneficial shareholder"
Sea train – not directly involved
– a second line corporate bond

Chat Chatterton

– p 42 14.3 – whose language is that?

Fred Alpetco

Ch p 43 15.1, 2, 3 whose language

Fred a combination

AGO 545671

Chatterton: a mutually agreed

upon article

For Yes!

Ch: p 32 10.2 (3) 18 mos prov.
not too diff to meet
their benchmark
Have they achieved
the step where they
can take the royalty
oil?

For Yes
Ch: p 33 10.2 (5) 30 mos prov
commence construction
of facility —
It is conceivable at this
point
by definition I submit that
this would be a 30,000 b/d
refinery — a portion of
used scale petrochemical plant
— the royalty oil (15%)
— this is as far as ALPET is
willing to go
— not go further
— If they take this position
and I refuse to meet
it/ any further
benchmarks, how can

AGO 545672

the state terminate contract?

Fr Yes
p14 - energy, aromatics, olefins, etc

a 30M refinery for energy fuels (4.2.2) will not satisfy olefins, aromatics, etc

Ch: Under this scenario, ALPETCO says "I disagree and I see you in the courthouse" and furthermore I will not perform under the under benchmarks

Fr: Contract will terminate under article 10

Ch: now lets talk about 14.3 - materially of Breach No default has occurred where you suffer no economic loss.

AGO 545673

Fr: One of the purposes is that one of the material

performance benchmarks is to construct and operate a facility.
— If benchmarks are not met, is not a breach but <u>default</u>

Ch: — force majeure clause seems to bail them out — defense line is wide enough to drive sev. tanks trough

Fr: I find it hard to believe that force majeure could apply, since it must be <u>beyond their control</u>.

Fr: Non-ability to borrow money is not grounds for force majeure.

Ch What about EIS or docking fac.

Fr: That's more likely to happen but not applicable since if they submit a EIS for 30M b/d ref. it is not in compliance with 10.2

Ch: You feel comfortable then?

AGO 545674

Fr: Yes

McK: Expend or commit to expend

Fr: Problem they had and which we recognized (listen to tape)

Fr Inability to get financing to commit what you promised to do will not be covered under force majeure.

Miles: 30M of in-state fuels - no requirement to process 150M
- No requirement to produce 30M either?

Fr: I can't shed any light on that struggled with language - we bumped into lots of problems anti-trust - this

AGO 545675

language is far as we could go
It was our conclusion that if the fac was here and the mkt was here, the incentive would be there for
— I was unable to come up with a solution

Miles — What about processing? Cloudy!

Fr — If you build a fac you have to put oil through No banker would allow them to ~~let~~ sit (it) ~~let~~ idle

M What about using another feed stock rather than oil?

Fr Doubt that they could get by without running oil through that refinery However, no prov. to run 150 M b through ~~the~~ refinery; but I just don't think it's

AGO 545676

economically viable!

Ch: 8.2 vs. last sentence of 8.1.1

Fr: "Settlement" in court suit rather than judicial determination!

Ch: What length of time is involved?

Fr: 2-3 yrs, maybe less!

Miles: Article 6 vs. 2.3 - quality -

Ch: Production decline after 1985 Rather rapid! ALPETCO - first refusal on all future royalty oil?

Fr:

Ch The possibility that new field could come on stream that would even keep up with the decline of PB is incomprehensible to me!

McK: Same terms + same conditions (2.3) Homer Spit Refinery

AGO 545677

Scenario as lead of ALPETCO

Fr: Never contemplated this
Have to meet the/all
the conditions.

Miles What about reduction in the
ALPETCO facility?

Fr: To prevent another fac coming
on line with cheaper feedstock!
— Yes, it would probably be
in alpetco's interest to take
2.3 option, even with
strings attached, even
if they have to shut
down 1st fac. since they
get oil cheaper.

Parr: How do you know that we are
well protected — loopholes?

Fr: Looked at other contracts
of this nature; and extensive
review by lots of people
ALPETCO's review is
also helpful as far as
their benefit.

AGO 545678

Parr: 70% clause - involved?
Leases with little "C" - reference
in contract

Miles: Future lease terms would
work advantageously for
State

Parr: Beaufort leases would
come under 70% prov.

EXCERPT FROM THE TESTIMONY OF JOE MOORE

April 5, 1978

CHAIRMAN MILES:

Joe, a couple of questions, I think, -- if you could put on your oil consultant hat for a moment. How serious is the possibility that the royalty oil contract will short circuit any gas, any possibilities of in-state gas process?

You seem to indicate that --

MR. MOORE:

Putting it in that sequence, I don't think it would make any difference.

That is if the royalty oil contract is approved and the process goes along, as I assume it will be scheduled to go along. I would estimate that a substantial chemical company, if they could be interested in the utilization of gas for a chemical plant -- I think that they would not consider the royalty oil contract as being inhibitive there. I think they would look at it as a certainty.

CHAIRMAN MILES:

Okay, that's what I don't understand. If there's going to be marketing problems of the two facilities; one facility is essentially substantially less expensive to build, it seems like there's going to be a problem downstream.

MR. MOORE:

Well I guess if you think about the ALPETCO cake as (Indiscernible) as ALPETCO has said, they're not committed to any particular product slate and in order for ALPETCO to build the plan on the scale that they have envisioned, that they have indicated that they would build, they have not built -- their investment schedule envisions building a big petrochemical plant. They could build something that would otherwise meet the state's criteria, having built something significant for a lot less -- say a billion and a half I think is their first cutoff point. Now what that really does, it ties them into building something pretty darn elaborate. (Indisc.) Now to build that petrochemical plant they have got to in some way market this product in a market which they participate. They have to penetrate a market that they're not involved in, that they're not in right now. I suppose that their strategy really would be that this penetration would be through some kind of joint venture. I don't know this, I'm just interpreting what I think I've heard ~~Hugh~~ Perry Spitz and Gordon Caine say, that they would be looking for people who are presently in that market but who would come in as some kind of a joint venture on the

plan with ALPETCO. Now if that were the case, then a joint venture partner would be -- well there would be ARCO, there would be EXXON, it would be SHELL, it would be GULF, it would be CARBIDE, it would be MONSANTO (ph) or it would be DOW. Now I don't think any of those people would go into partners with ALPETCO.

CHAIRMAN MILES:

Where does that leave ALPETCO then? Insofar as proceeding with the contract.

MR. MOORE:

I think to proceed on the full scale that they envision, I think they have real problems as I have said in my report. They may proceed -- they may very well find that nitch that they can proceed on and I think it's fair to say that their thinking is probably pretty wide open on that point. But the project that was proposed originally by John Barbour which I think is the only really written version we have seen with the scope of what the ALPETCO project would be -- I think they can't do that. Now I'm not saying they can't do something, but I don't think they can do that.

CHAIRMAN MILES:

Well what do you envision them doing?

MR. MOORE:

Well it would be feasible for them to build a fuel refinery and a third stage to which they would start adding some petrochemical operations.

CHAIRMAN MILES:

Based on crude oil or --

MR. MOORE:

Yeah, crude oil. I mean let's just take -- forgetting the gas for just a moment, let's just take one of the scenarios which is most likely of success for ALPETCO. Well I think the first criteria will be that the most successful thing they can do would be something that would be simple. And the simplest thing they could do would be something that would be (1) essentially a fuels refinery, a core plant to start with. What's the next simplest thing that they could do? Well probably produce some (2) aromatics. What's the next simplest thing that they could do beyond that -- (3) a few specialty chemicals. Now you're building up to the point that can they at some point develop a position in the

market such that they could competitively go up against the real big companies and force their way into the (indisc.) market. Well with some financial substance behind them, the plant in place, they've got lots -- they've got maybe a chance for doing that. What I have felt was wrong with the plan that they originally proposed was that there was no way that they could go into that market with those big companies and succeed. That those companies would keep them out and in my report I pointed out that in the chemicals business, unlike the fuels business, market share is guarded very carefully by those people who are in the market. And they really fight for market sharing on a competitive basis. And they don't really in the fuel oil business. I mean a few of them do but, you know, fundamentally EXXON and ARCO aren't out fighting for fuel oil business. If somebody wants to sell fuel oil, undercut them $.10 a barrel, fine they'll do something else with their oil, they won't really fight them for it. But in the chemicals business, because of the high profit margin during the good times, they'll fight for their share of the market. And they fight by cutting the price. But ALPETCO is going to run against them. If they start trying to sell ethylene, they're going to run up against a situation where (a) they're unproven suppliers and where they're going to go to is being supplied to somewhere else. Now they're going to be able to woo them away from that alternate supplier either by cutting their price below the price at which their present supplier will cut price and they can't cut the price as low as their present supplier will cut price or they're going to have to (indisc.) say ALPETCO has a -- represents an assurance of future supply, which is better than their alternate supplier and furthermore that they will be willing to pay enough more for that future assured supply since there's the fact that their competitor's going to cut price more than ALPETCO can cut price, will still give them the incentative to come with ALPETCO. But ALPETCO will never be able to cut the price as low as EXXON will cut the price or as ARCO will cut the price or MONSANTO and so forth will cut the price, they just can't do it. So they've got to figure out another way to attract somebody to buy from them. And that's pretty hard to do. When somebody else will cut the price to whatever it takes to keep the business, it's hard to get away from it. And that's the fundamental problem they're going to have.

CHAIRMAN MILES:

Well I'm still unclear as to how that statement relates to what your report says. Liquids availability at the right price would likely require that the oil project be abandoned and converted to the use of NGL (ph). Either it's -- and maybe I'm just making this too black and white, but it seems to me it's going to short circuit NGL development or it's not. I don't get what the balance is or what the ratio is.

MR. MOORE:

Well I don't have a certain answer to the question either. I would say this though that if you had -- let's take ARCO, they're a big ethylene producer and they produce on the North Slope. Now if ARCO decides that it made sense to them to supply the West Coast ethylene market growth with gas liquids, I don't think that ALPETCO's -- the fact that ALPETCO is out there also, would deter them a moment. I think that they could figure that they could kick ALPETCO out of any situation that ALPETCO was in. They've got the financial muscle, the marketing muscle and everything else to do it. If it were the other way around, I think there would be a problem. I think the fundamental issue in the chemicals business is the -- not in the chemical business in general -- but the ethylene business, particularly, is that that is a very big company business. And pretty big companies have been forced out of that business because they didn't have the financial resources. And if you look at people who are in it now. It's nothing but the very largest corporations because it has gotten to require so much capital and willingness to absorb substantial downside risks under poor market conditions. It's just a game that small companies can't play.

CHAIRMAN MILES:

You're not answering my question.

MR. MOORE:

Alright, phrase it again.

CHAIRMAN MILES:

I'm trying to find out how approval of the ALPETCO contract will affect the development of gas or gas liquids in the state? Well that does seem contrary to what you said in your report.

MR. MOORE:

The report -- oh, okay I see what your problem is. If these were two separate activities (a) you had the ALPETCO contract you sign it then (b) you wanted to do something to develop the gas liquids thing. When you sign the ALPETCO contract you have not said that. What you have signed is a contract to develop a petrochemical complex. I think that is a very important understanding.

CHAIRMAN MILES:

Do you want to repeat that last one.

MR. MOORE:

Well ALPETCO has a guarantee it can build a petrochemical complex.

CHAIRMAN MILES:

I just want to make sure I heard you right.

MR. MOORE:

That's what their intention is. And that's what everybody hopes that they're able to do. But it could well turn out that the thing they -- if they put something together it may be something that does not involve a petrochemical complex initially. So that's the first point. You haven't necessarily said you're going to build a -- create a petrochemical complex by ALPETCO. And the second thing is that if you could find someone who is -- if you had a good deal on a gas liquids side, and you really were -- and you had made a policy decision that ALPETCO was the group that you were essentially cooperating with in this kind of development, then you probably would want to give them this favorable opportunity. Now if you did not choose to do that, if you said well, ALPETCO's on their own, you know, the state has no more relationship with them other than just having signed this contract guaranteeing them a supply of royalty crude and now we want to set up a -- want to entice a big chemical company to come into the state and use these gas liquids, I don't think the existence of the ALPETCO contract would deter per se would deter, you know, an ARCO or a DOW to come into here and looking at the gas liquids, if they were otherwise inclined to do so. I just don't think that the ALPETCO contract -- they would weigh it one way or the other.

CHAIRMAN MILES:

Okay. Let me put it this way then. If ALPETCO entered the contract and it's approved, does what it says it's going to do, 30,000 barrels of fuel and the rest in petrochemicals, would you recommend to a major client that they go in and develop a gas liquids facility?

MR. MOORE:

If I was sure that ALPETCO would do that?

CHAIRMAN MILES:

Yeah.

MR. MOORE:

No, I wouldn't.

MR. CHATTERTON:

Is that because the market in other words is full ~~in~~ even enough now, saturated enough now that one plant might break but two would be doggone (indisc.)

MR. MOORE:

And so fundamentally I'd just repeat that I think that ALPETCO --I think it's unlikely that ALPETCO in their first realization and what their affect on the market is over the next two years or 18 months or whatever it is, I think it's unlikely that they will really be a factor in the ethylene market or the ability of a major present supplier to promote a new plant. I just don't think they'll be a factor.

MR. CHATTERTON:

If ALPETCO -- if there weren't the strings attached, why ALPETCO was trying to penetrate this market, why would they be in a much more competitive position to do so if the state's royalty share of the oil was transported to California to a petrochemical plant on the West Coast?

MR. MOORE:

Well I think the whole problem -- the point I'm trying to get across is that I see the biggest deterrent as being one that your logic in coming must be that ALPETCO -- you're going to try to keep them out of the market, regardless of their feed stocking, regardless (indisc. -- cough).

MR. CHATTERTON:

But whether it be Valdez, Kenai or the West Coast, that would be under the terms of the contract with the State of Alaska, but there is some other thing where ALPETCO could -- there is permissiveness in the contract where ALPETCO could knock anybody else out of the market.

MR. MOORE:

The contract, yeah, but not in the bank book.

MR. CHATTERTON:

But in the contract why it's permissive -- I mean presupposing they could get their feed stock at $.50 a barrel. They could do a pretty good job, (indisc.). Even if we gave them the oil?

MR. MOORE:

Well I'd say it's in the range of feasible alternatives. I

think that it doesn't help. I don't think that they are particularly helpful one way or the other.

MR. CHATTERTON:

I see, thank you.

MR. MOORE:

We have worked with so many projects where people have tried to break into the ethylene market, people double the size of ALPETCO or even some a little bit bigger and at some point it gets down to the fact that you've got to have lots of guts or your banker's got to have lots of guts to go ahead because there's so many ways that competitors can keep you out of that market and if they're bigger than you are and they want you out of the market at some point you come to a premise that no one you've ever dealt with before has been able to -- you know, they've all backed away. And they may back away for all sorts of reasons. They can't get the financing, they can't get the contracts, so on and so forth. That's just a really rough game.

MR. PARR:

You said something about this a little while ago and I'm afraid I didn't hear you as well as I'd like to. You were talking about in the lower 48 petrochemical plants based on gas liquids hadn't been able to compete whereas this state's position versus (indisc.--loud noise) because of amortization.

MR. MOORE:

Yes, amortization of the total costs.

MR. PARR:

Yeah, and you said that they could absorb, I guess, fluctuations in price, low prices for (indisc.) I wasn't really quite -- I know so little about economics in business that I'm embarrassed but nevertheless I didn't quite understand what it was you were saying. If I understood you right, let's say this plant that ALPETCO's going to have a 2-1/2 million dollar plant, this one might be say a billion dollars, they're both selling the same product, ethylene. Now how does the fact that there's a bigger investment than the ALPETCO plant, I mean assuming that it's one of (indisc.) lower 48 situation, it wouldn't be quite as true up here. But how does that fact that one of them costs twice as much today, help them?

MR. MOORE:

Well, okay. The (indisc.) has two characteristics, one is that it produces a wider range of products and secondly is that of it's total cost, only half of that cost is variable.

MR. PARR:

Their bonded indebtedness or whatever kind it is.

MR. MOORE:

The (indisc. -- simultaneous speech) cost of that plant.

MR. PARR:

That's the same year in and year out (indisc. -- simultaneous speech)

MR. MOORE:

(Indisc. -- simultaneous speech) some costs. But the cash flow that's produced by the plant only has to account for half the total cost which is the feed stocks, utilities and labor support. So if I want to cut the price if I want to compete, you know, cut the price. I can cut my price 50% and still have net dollars coming in every day from the operation of this plant. Now sure, I'm not paying the bank off as fast. Maybe I'm not paying myself back as fast on some investments. But in terms of just the sheer money coming in for the product, less the money going out for the feed stock and the utilities, I can cut prices 50% and still make a positive cash flow.

MR. PARR:

That's if your bank will let you get by with that.

MR. MOORE:

That's right. And then, of course, for that reason, you don't see anybody getting a crude oil plant -- there is no crude oil plant in the word that's not operated by an oil company.

MR. PARR:

So they have (simultaneous speech). The guy that runs the gas liquids plant though doesn't mean they are in the same position, right. There's a higher percentage of his costs are the variables, the cost of the feed stock and so forth.

MR. MOORE:

It could be over-simplifying to say whether it's good or bad. Because I could say well the crude oil plant has more products, therefore it's diversified and therefore that's good. But if you're going into a virgin market, that's bad because you've got to sell so much stuff.

MR. PARR:

So if the price of ethylene is low and the price of something else is high at this time you have a chance to sort of balance it off.

MR. MOORE:

Well if you look at the Gulf Coast where you have all the petrochemical industry there, a crude oil plant that produces all of these byproducts, there's someplace for all of those products to go because there's some plant around there that takes all of these products. Now by contrast, if you look at Saudi Arabia, something you read about in the news, they're looking at several ethylene plants but they're all ethylene plants because there's no plant anywhere around that takes anything. So their marketing problem is very complex and they'd like to just produce one product if they can, based on one product. That's a lot better than selling two products. So in all cases they're looking at the simplest plant that they can come up with so they have the simplest marketing problems; the simplest transportation problems. And this is kind of the analogy that we followed in thinking that the ethylene plant is kind of the obvious one for Alaska because you really have a virgin market. You don't have an infrastructure of other plants around you. And you have to create all that at one time; that means more money, more loose ends you have to pull together.

MR. CHATTERTON:

Well following up on that Joe, suppose we okay the contract with ALPETCO and they go ahead, and they're starting a business -- they're trying to break into the market to produce the products (indisc.) And then if somebody did decide to go into the gas liquids plant, it's going to make ALPETCO's job perhaps even harder because they've got one more competitor who can produce perhaps more cheaply than they can.

MR. MOORE:

Well I think that's true. When you're thinking in terms of ALPETCO trying to build a major petrochemical plant but under the terms of their contract, they don't have to do that.

MR. CHATTERTON:

I understand that. This is just a hypothetical case. Under their contract they have to produce 35,000 barrels of crude (indisc.)

MR. MOORE:

(Indisc.) 100,000.

MR. CHATTERTON:

Billion and a half dollars in a certain period of time or else they lose their contract.

MR. MOORE:

Yes, and that's tough. That's pretty well -- if you really stuck it with that it would tie it to --

MR. CHATTERTON:

A billion and a half is more than you can justify on just producing an amount of fuel oil and gas so they'd have to do something with it or else ...

MR. MOORE:

And personally I think ALPETCO was dumb to have agreed to that. And I think that it is not in the state's interest to hold them to that even. If ALPETCO could come up and show that they had put together a deal for 700 million dollars, 600 million dollars at the end of 18 months, they reap the contract terms and it seems to me inequity that that is a significant affair -- discharge of their obligation. And I look at it, if I were in a position of having to decide whether -- what ALPETCO had done was in conjunction with what the intent of the state was when they started out this royalty oil thing, I'd be hard pressed to say that they could spend 600 million dollars or 700 million dollars on an oil processing facility, that there was anything wrong with that.

MR. CHATTERTON:

(Indisc.)

MR. MOORE:

Well, it is, 600 million dollars is a lot of money.

MR. CHATTERTON:

Not Alaskan terms.

MR. MOORE:

In the refinery and petrochemical industry, it is. I don't

think and I'm not positive of this, but I don't believe that it has yet been grass roots project built for a billion dollars. And you talk about it so much that you almost think it's actually been done. I don't think it's ever been done.

CHAIRMAN MILES:

What's a grass roots project?

MR. MOORE:

Oh when you start off with nothing, just build it. I go out with the grass roots and I create a plant. That's what we call a grass roots plant.

CHAIRMAN MILES:

How do they get them built?

MR. MOORE:

Well they do but there hasn't been one built that big yet.

CHAIRMAN MILES:

They're built in stages.

MR. MOORE:

Well yeah, they're built in stages and also most chemical complexes start off much smaller and so forth. You're talking about something that we've written -- seen so much of the literature about, numbers of this size. And we've almost gotten to assume that these things have really been done, but they haven't been done. Now we talked about billion dollar plants in Saudi Arabia and we talked about even -- well I look at a billion dollar and a half plant in the U. S. They've never gotten built. So we're talking -- you just get kind of hypnotised at the fact that the pipeline cost 8 billion dollars. Yeah, but look who's behind the pipeline.

CHAIRMAN MILES:

What are these 200,000 barrel a day OPEC petrochemical facilities cost?

MR. MOORE:

They haven't been built yet.

CHAIRMAN MILES:

I know, but -- I know they haven't been built yet but --

MR. MOORE:

Billion and a half, 2 billion dollars.

MR. CHATTERTON:

(Indisc.)

CHAIRMAN MILES:

Chat.

MR. CHATTERTON:

Thank you, Mr. Chairman. What's your definition of a petrochemical?

MR. MOORE:

Of a petrochemical from oil, from a hydrocarbic source?

MR. CHATTERTON:

Well if I were to build a petrochemical complex, buy a petrochemical complex and I made this a middle of the barrel fuel product slate, (indisc.) propane, a little butane, wouldn't that be a petrochemical complex?

MR. MOORE:

Well there isn't a legal definition of it.

MR. CHATTERTON:

There is no legal definition, is there?

MR. MOORE:

It's a term of art.

MR. CHATTERTON:

It's a great, broad, wide open (indisc.)

MR. MOORE:

We could probably decide in the sense of it being a term of art. But, you know, a normal person (indisc.) petrochemical complex.

UNIDENTIFIED SPEAKER:

That would make (indisc. -- laughter).

MR. CHATTERTON:

Joe, thank you, you've made a point, I hope. I don't want to admit it.

MR. MOORE:

Any other questions?

MR. PARR:

Tell me one thing and this, again, is an off the top of the head answer. I've got to tell you that this one company came in and discussed with a number of us on this committee, I guess, the possibility of building a strato-plant (ph) over the gas line in Fairbanks and they buy the gas and they put it through a process (indisc.) liquids and (indisc.). It's their responsibility to market the stuff. Is it your off-hand guess that such a thing might be economically viable?

MR. MOORE:

Yeah.

MR. PARR:

Do you have much information (Indisc.).

MR. MOORE:

I think the thing that -- I think that if you just do that by itself, the thing that you probably clearly could do, you could probably recover propane, butane, (indisc.) and sell those. Now that probably wouldn't really contribute anything significant to development in the state if that were your objective.

MR. PARR:

(Indisc.) planned use.

MR. MOORE:

That people would use?

MR. PARR:

Something like the (indisc.--interrupted)

MR. MOORE:

(Indisc.) people.

MR. PARR:

It would be a real big plant.

MR. MOORE:

Oh a hundred people probably.

MR. PARR:

So in terms of an increment of employment or development it's not a real big increment.

CHAIRMAN MILES:

No, it's a term of art, (indisc.) It's a downstream manufacturer is what you'd call it -- the guy who would buy this propylene or whatever it is to make something out of it.

MR. MOORE:

Make something else out of it.

MR. PARR:

And then he came along and located (indisc. -- interrupted)

MR. MOORE:

(Indisc.)

CHAIRMAN MILES:

(Indisc.)

MR. CHATTERTON:

Joe, what's a commercial name for aromatic, one of the aromatics?

MR. MOORE:

Benzine, you mean?

MR. CHATTERTON:

Okay. Let's say the bottoms from the fuel oil refinery would contain those, would it not?

MR. MOORE:

The bottoms from the fuel oil refinery?

MR. CHATTERTON:

Well the tops -- in other words, what you didn't -- if you had products like jet fuel, diesel, stove oil and the rest shifts out why that would have -- what shifts out would have aromatics in those, wouldn't it?

MR. MOORE:

Aromatics are into gasoline (indisc.) If you make these in a plain old refinery, that made gasoline --

MR. CHATTERTON:

I'm not making gasoline.

MR. MOORE:

The aromatics of commerce appear in the gasoline business.

MR. CHATTERTON:

And if I don't take any out why they're still in there, aren't they?

MR. MOORE:

Yeah.

MR. CHATTERTON:

I've separated them from something.

MR. MOORE:

There's lots of aromatics, you know, if you try to be literal but the aromatics of commerce are primarily benzine and secondarily zyalene (ph) and third (indisc. -- noise) and anything else is not really an aromatic of commerce.

MR. CHATTERTON:

And where would our olefins fit into commerce?

MR. MOORE:

If you're not thinking gasoline?

MR. CHATTERTON

No.

MR. MOORE:

Well if you had atomic refinery, you don't have any olefins. Olefins are primarily produced in a refinery by a cracking process (indisc.)

MR. CHATTERTON:

Okay.

MR. MOORE:

Gas, oil.

MR. CHATTERTON:

Alright.

MR. MOORE:

(Indisc.) cracking bottoms or they're produced by thoroughly cracking naptha. In the petrochemical business they're primarily produced in cracking steam, so called steam cracking or steam pyrolosis (ph) a derivative material producing ethylene and propylene. So that if you had a simple refinery, you normally wouldn't have any olefins (indisc.) If you start producing olefins in a normal refinery you do it because you're making --increasing the octane of gasoline. If you're not making gasoline and you're producing olefins, you're probably producing chemicals like ethylene and propylene.

MR. CHATTERTON:

Okay. Thank you. Thank you, Mr. Chairman.

CHAIRMAN MILES:

Anything else? Joe, thank you very much. You were very, very helpful.

PETRO MARKETING SERVICES, INC.

PETROMARC

(2) He still makes no argument for interim taking. Cell the reasons for not allowing interim sales remain

(3) What about other concerns! "commit to expend" pp 1, 5.

Supplementary Statement By

Earl Johnson

Before The

Senate Special Committee on Royalty Oil and Gas

State of Alaska

May 15, 1978

(1) "The scope of my concern and my comments is essentially from the standpoint of effective crude oil marketing -- the area of my special expertise..."

Doesn't seem he knows too much about marketing to revise his statements so drastically!!!

AGO 54[illegible]697 +

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Senators.

Since testifying before this committee on May 11, I have received and noted several items of additional information that I consider pertinent and highly significant -- enough so, in fact, to appreciably alter some of my attitudes toward the Alpetco contract as it pertains to royalty oil purchases. These changes also must affect my testimony and I should like to make the following brief statement prior to further consideration of the Alpetco matter.

Following my testimony on May 11, I discussed the Alpetco contract with Commissioner LeResche and Deputy Commissioner Boness, especially with regard to my testimony which opposed early taking of royalty oil. I characterized such early taking of crude by Alpetco as a probable indirect subsidy to the project by the State due to my visualizing an opportunity for Alpetco to purchase crude under the contract's pricing formula at a price which would permit them to discount North Slope royalty oil on the West Coast -- and still make a profit.

I found my discussion with Mr. LeResche and Mr. Boness very enlightening. Both of these gentlemen are exceptionally well informed both with respect to the subtleties of the Alpetco

contract and with respect to the crude oil marketplace generally.

In arriving at some of the conclusions outlined in my earlier testimony, I had used a weighted average price FOB Valdez of $11.45, based on the marketing of 2/3 royalty oil on the West Coast (and Valdez) and 1/3 on the Gulf Coast. These figures are essentially correct, but do not fully address the unique pricing mechanism in the proposed contract. This pricing mechanism contains a feature that substitutes the average point of delivery price of all of the other producers for the actual price of any producer whose actual point of delivery price is lower than the weighted average price of all of the other producers. This feature tends to protect the state from receiving a low price from Alpetco under any circumstance, but especially under those actual crude marketing practices now existing with respect to North Slope crude. Specifically, some 61% of North Slope Crude was marketed at Valdez and on the West Coast during March 1978, with the other 39% going to the Gulf Coast. The calculated weighted average price at TAPS inlet was $5.16 per barrel ($11.43 FOB Valdez). However, the pricing in the contract would set the Alpetco purchase price under the contract at $6.09 at TAPS inlet ($12.36 FOB Valdez). Since this would result in a delivered West Coast cost to Alpetco of approximately $13.25, there would obviously be no incentive for Alpetco to exercise its crude option -- and certainly no way to discount in the West Coast Market

Didn't he read the contract?

(since the going rate forNS crude is approximately $13,00 per barrel at present.) This pricing anamoly results essentially from the fact that almost all of the crude going to the Gulf Coast is Sohio's. Their crude is thus priced at a weighted average $4.34 at TAPS inlet. Since the weighted average price of all other producers (excluding Sohio) is $6.09, this price is substituted in the pricing formula as the price per barrel for Sohio's crude in weight averaging all crudes. The foregoing prices are based on actual volumes and prices as reported to the State for March 1978. I have calculated additional simulated conditions for March and have concluded that even if Sohio commenced marketing an additional 100,000 barrels per day on the West Coast instead of the Gulf Coast, and Exxon and Arco each sold 50,000 more barrels per day on the Gulf Coast instead of the West Coast, the Alpetco price at TAPS inlet would still be $5.53 ($11.80 FOB Valez = $12.70 West Coast). Even this very substantial change in West Coast market balance between companies (which I do not regard as likely in the near future) would not produce a contract price low enough to permit Alpetco to discount significantly in the West Coast market and still achieve a profit on the sale of crude.

Because of this special pricing feature, the full import of which I had not realized at the time of my earlier testimony, I now believe there is very little likelihood of Alpetco's early taking of crude; and even less likelihood that if such early taking does occur (after 25 months), that the State

What about their most recent forecasts?

AGO 545700

would be adversely affected as to price. In the light of my more complete information, I visualize the Alpetco's possible sales of crude on the West Coast would have no serious effect in the West Coast marketplace. I retract my earlier statement regarding the crude option to Alpetco constituting an indirect subsidy by the State to the Alpetco projects, since I have been convinced that the State is reasonably protected by the pricing clause.

The foregoing represents a substantial alteration in my testimony since last week. Briefly stated, I now feel much more comfortable about the crude dedication features of the Alpetco contract.

they should! Their negotiated new contract

As earlier stated, I have been very favorably impressed with the grasp that your Royalty Commissioner and his staff have of the contract and its implications. Certainly, from the standpoint of the present administration attitude, one can feel assured that the bench mark requirements would indeed be rigidly and narrowly interpreted.

Thank you for the opportunity to amend my earlier testimony. My change of attitude about part of the contract is based on several hours of calculation based on actual March 1978 movements of crude as reported and an application of the Alpetco purchase price clause to these actual crude deliveries and modifications thereof.

AGO 545701

AMENDMENT

Dated May 17, 1978

to the

AGREEMENT FOR THE SALE AND

PURCHASE OF STATE POYALTY OIL

THIS AMENDMENT entered into as of the 17th day of May, 1978, by and between THE STATE OF ALASKA, hereinafter called the "Seller," acting by and through its Commissioner of Natural Resources, and ALASKA PETROCHEMICAL COMPANY, an Alaska corporation, hereinafter called the "Buyer," and being the Amendment to the Agreement between Seller and Buyer entered into February 22, 1978.

WITNESSETH:

WHEREAS, an Agreement for the Sale and Purchase of State Royalty Oil was duly executed on February 22, 1978, between the State of Alaska, as Seller, and Alaska Petrochemical Company, as Buyer ("Agreement"); and

WHEREAS, the Agreement may be amended under Article XXII thereof; and

WHEREAS, Seller and Buyer desire to clarify certain intentions of the Buyer and Seller therein;

NOW THEREFORE, in consideration of the representations, covenants and conditions herein contained, Seller and Buyer hereby amend the Agreement as follows:

1. Article 1.13 is hereby amended by adding the following sentence at the end of Article 1.13:

"Total Project Costs shall not include any amounts paid for the purchase of crude oil."

2. Article I is hereby further amended by the addition of Article 1.14 which reads as follows:

"1.14 The terms "committed to be expended" as used in Article 1.13 and "commit to expend" as used in Article 10.2 shall mean contractually binding agreements, contracts and purchase orders."

3. Article 2.2 is hereby amended by the addition of a sentence at the end of such Article 2.2 as follows:

"Notwithstanding any other provision of this Article 2.2 Buyer shall not be entitled to receive delivery of any royalty crude oil hereunder until (a) Buyer has actually expended at least $100 million in Total Project Costs, and (b) at least twenty-five (25) months have passed since the Effective Date."

4. Article II is further amended by the addition of a new Article 2.7, to read as follows:

"2.7 Reduction of Quantity of Oil Deliverable to Buyer. Notwithstanding any provision of Article II requiring Seller to deliver to Buyer quantities of crude oil up to 150,000 barrels per day, in the event six years after the Effective Date the

capacity of the Petrochemical Facility is less than 150,000 barrels per day, the maximum quantities deliverable by Seller for the remaining term of this Agreement shall be reduced to that quantity equal to the capacity of the Petrochemical Facility at such time. Coincident with such reduction, the figure "145,000 barrels" appearing several places in Article 2.4 shall be reduced by a like amount. For the purposes of determining capacity under this Article 2.7, the capacity of the Petrochemical Facility shall not be diminished or reduced because of temporary reductions due to market conditions or shutdowns in the Petrochemical Facility, regardless of cause.

5. The first sentence of Article 4.2.1 is hereby amended and revised to read as follows:

"4.2.1 Construction Obligations. In consideration of the obligations assumed by each party herein, Buyer will proceed with reasonable diligence to design, construct, start up and thereafter initiate operation of a petrochemical manufacturing and fuels refining facility in the State of Alaska with capacity to process at least 150,000 barrels of crude oil per day."

IN WITNESS WHEREOF, the Seller has caused this Agreement to be executed by its Commissioner of Natural Resources and the Buyer has caused this Agreement to be executed by its

Chairman of the Board, thereunto duly authorized by its Board of Directors in accordance with the certified seal, duly attested, to be affixed hereto, as of the day and year first above written.

THE STATE OF ALASKA

ATTEST:

BY:
Commissioner, Department of Natural Resources
"SELLER"

APPROVED AS TO FORM:

ALASKA PETROCHEMICAL COMPANY

ATTEST:

BY:
Chairman of the Board
"BUYER"

AGO 545705

AGREEMENT FOR THE SALE AND PURCHASE

OF

STATE ROYALTY OIL

ALASKA PETROCHEMICAL COMPANY
an Alaska corporation

THE STATE OF ALASKA
Department of Natural Resources

February 22, 1978

AGO 545706

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AGREEMENT FOR THE SALE AND

PURCHASE OF STATE ROYALTY OIL

THIS AGREEMENT entered into as of the 22nd day of February, 1978, by and between THE STATE OF ALASKA, hereinafter called the "Seller," acting by and through its Commissioner of Natural Resources pursuant to Alaska Statute 38.05.183 and ALASKA PETROCHEMICAL COMPANY, an Alaskan corporation, hereinafter called the "Buyer."

W I T N E S S E T H :

WHEREAS, it is in the mutual best interests of Seller and Buyer that Buyer construct and operate a petrochemical facility in Alaska to process the oil sold hereunder, said facility to have the capacity to process approximately 30,000 barrels per day of crude oil into energy fuels for in-state distribution and sale; and

WHEREAS, Seller has the right under each of the leases identified in Exhibit "A" to this Agreement to be delivered or paid by the Lessee thereunder a royalty of twelve and one-half percent (12-1/2%) in kind (amount) or value of the crude oil production removed or sold from the lands covered by each such lease; and

WHEREAS, the Lessees of such aforesaid leases and other parties have represented to Seller that crude oil can be recovered from such leases in significant quantities and that such Lessees intend to market such crude oil; and

AGO 545712

WHEREAS, Seller is presently receiving royalty payments based on more than 90,000 barrels of crude oil per day from the aforesaid leases and anticipates the quantity of such royalty oil payments to increase for the next year; and

WHEREAS, Seller is authorized by Alaska Statute 38.05.183 to sell such royalty oil; and

WHEREAS, Seller desires to sell royalty oil to Buyer and Buyer desires to purchase royalty oil from Seller under the terms and upon the conditions hereinafter set forth;

NOW, THEREFORE, in consideration of the representations, covenants and conditions herein contained, Seller and Buyer hereby agree as follows:

ARTICLE I

DEFINITIONS

As used herein, the following terms shall have the following meanings:

1.1 "Affiliate" shall mean any person, firm, corporation or other entity affiliated with Buyer by means of a material direct or indirect ownership interest.

1.2 "Commissioner" means the Commissioner of Natural Resources of the State of Alaska.

1.3 "Date of First Delivery" means the date the first royalty oil sold hereunder passes the Point of Delivery.

1.4 "Day" means a period of twenty-four (24) consecutive hours beginning at 12:01 a.m., Alaska Standard Time.

1.5 "Effective Date" shall have the meaning defined in Article XI.

1.6 "Force Majeure" shall have the meaning defined in Article 15.2.

1.7 "Leases" or "Lease Contracts" means the oil and gas leases which are described in Exhibit "A" attached hereto and made a part hereof.

1.8 "Lessee" means any party owning a working interest in a Lease or Lease Contract.

1.9 "Month" means the period beginning at 12:01 a.m., Alaska Standard Time, on the first day of the calendar month and ending at the same time on the first day of the next succeeding calendar month.

1.10 "Oil" or "crude oil" shall have the same meaning as the word "oil" under the Prudhoe Bay Unit Agreement dated April 1, 1977, by and between the Seller and Lessees.

1.11 "Point of Delivery" shall have the meanings defined in Article III.

1.12 "Petrochemical Facility" shall have the meaning defined in Article 4.2.1.

1.13 "Total Project Costs" shall mean the aggregate of all sums and costs expended, incurred or contractually committed to be expended by Buyer, its Affiliates, direct and indirect beneficial shareholders, consultants, advisers and design, engineering and construction contractors in connection with responding to the requests

for proposal for the sale of royalty oil from the Leases; the preparation and execution of this Agreement; the performance of any and all obligations, transactions or events required by this Agreement; and the design, engineering and construction of the Petrochemical Facility or any portion thereof, all such costs to be measured from January 1, 1975. Total Project Costs shall also include (i) interest costs actually paid or accrued, and (ii) sums and costs expended, incurred or contractually committed to be expended by any city, borough or other governmental agency on any pollution control, sewage or water treatment, port, pipeline, terminal or other facilities, directly connected with or a part of the Petrochemical Facility, to the extent such facilities are utilized by the Petrochemical Facility. Any indirect or allocated costs shall be substantiated in writing to the satisfaction of the Commissioner.

ARTICLE II

QUANTITY PURCHASED AND SOLD

2.1 Sale of Prudhoe Bay Royalty Oil. Subject to the terms and conditions hereinafter provided, and subject to the prior obligations of Seller to deliver 5,000 barrels of crude oil per day under its contract with Golden Valley Electric Association, Inc. ("Golden Valley"), for the term and in the quantity now stated therein, Seller agrees to sell to Buyer, and Buyer agrees to buy from Seller, eighty-five percent (85%) of the total amount of Seller's royalty oil out of the crude oil production removed or sold from the Leases which the Seller has the right to take, and is available to the Seller for tak-

ing, in kind. Seller reserves the right to use or dispose of the remaining fifteen percent (15%) in its discretion. After completion of the Petrochemical Facility, Seller's obligations to Golden Valley, if any, shall first be satisfied out of the fifteen percent (15%) portion of the oil from the Leases not being sold by Buyer hereunder. In addition to the crude oil deliverable under the other provisions of this Article 2.1, Buyer shall also possess the option to purchase an additional five percent (5%) of the total amount of Seller's royalty oil out of the Leases:

(a) in the event Seller enters into a contract with North Pole Refining Company ("NPR") granting NPR an option to purchase part or all of the fifteen percent (15%) portion of the oil out of the Leases not sold to Buyer under other provisions of this Article 2.1 and NPR does not exercise its option in full to purchase the oil on which it has an option, but Buyer's option to purchase shall extend only to the purchase of that quantity of oil from time to time not purchased by NPR; or

(b) in the event Seller does not enter into or have in effect a contract with NPR as recited in Article 2.1(a).

In the event it exercises its option under Article 2.1(a) or 2.1(b) above, Buyer agrees to give Seller an additional thirty (30) days notice of any nominations under this Article in addition to the time for notice specified in the Prudhoe Bay Unit Agreement. In the event under any agreement with NPR Seller obtains a right to purchase

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from NPR any oil returned to the Trans Alaska Pipeline System by NPR, Seller shall assign all such rights to Buyer for the term of such NPR agreement.

Seller represents to Buyer that it has obtained sufficient advance written consents to termination and an agreement from Lessees (which to Seller's knowledge has been performed) to require similar consents from all subsequent purchasers agreeing to waive or terminate any supplier-purchaser relationship as to sufficient quantities of Seller's royalty crude oil out of the Leases to enable Seller to perform its delivery obligations under this Agreement.

2.2 Initiation of First Delivery. After the date Buyer has obtained the financing commitment referred to in Article 10.2(3)(d) and has furnished satisfactory evidence of same to Seller, Buyer shall have the right, subject to the further terms of this Article 2.2, to call for the initiation of delivery of crude oil under this Agreement by notifying Seller that Buyer seeks to initiate deliveries and stating the quantity desired, which such quantity shall be not less than one thousand (1,000) barrels per day. Initiation of deliveries, therefore, may occur prior to the date the Petrochemical Facility is completed and operational. Seller, within thirty (30) days after receipt of such notice from Buyer, shall deliver notice to all Lessees that it is exercising its right to take its royalty oil in kind and stating the quantity required to be delivered. In the event Seller shall obtain a modification of the Lease Contracts or Prudhoe Bay Unit Agreement to reduce the notice period required to less than six (6) months, the Date of First Delivery under this Agreement shall be reduced accordingly, but only upon sixty (60) days' prior written

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notice of such time reduction to Buyer. Buyer agrees, in the event it calls for delivery of crude oil prior to the date the Petrochemical Facility is ready to process the crude oil, that it shall fully comply with its obligations under Article 26.6.

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2.3 Certain Future Sales of Oil Taken in Kind by Seller. From and after the Effective Date, as to any royalty oil of Seller (other than royalty oil out of the Leases) taken in kind and proposed to be offered for sale, other use or disposition to third parties by Seller at a price or value which, when the reasonable costs of transportation of such royalty oil to the site of the Petrochemical Facility are added thereto, is less, on the date so offered, than the price stipulated in Article 8.1 plus the reasonable costs of transportation from the Point of Delivery to the site of the Petrochemical Facility, equitably adjusted to reflect quality and gravity differences between the crude oil offered to be sold and the crude oil from the Leases, Seller shall first offer to Buyer the opportunity to purchase ninety percent (90%) of the royalty oil proposed to be offered. Said oil shall be offered to Buyer at the same price, and on the same terms and conditions, as offered to third parties. The offer to Buyer shall remain open for sixty (60) days, after which time, if Buyer has not accepted the offer, Seller shall be free to sell the oil under the same terms and conditions to a third party. Seller may freely dispose of the ten percent (10%) portion of the royalty oil not sold to Buyer hereunder at such price and on such terms as Seller may desire. Notwithstanding the preceding provisions of this Article 2.3, Seller may freely sell any of its royalty oil otherwise subject

to this Article 2.3 free of the terms of this Article 2.3 so long as any such sales and deliveries of oil at a lower price, as defined above, cease and terminate on the date the Petrochemical Facility initiates processing of crude oil; further, the provisions of this Article 2.3 shall not apply to Seller's currently pending contract for the sale of oil out of the Leases to North Pole Refining Company and except for any renewal or renewals of the current contract of Seller with Tesoro Petroleum Company ("Tesoro") for a like quantity of oil as is now being delivered under Seller's contract with Tesoro. If Buyer purchases oil pursuant to the provisions of this Article 2.3, Buyer may reduce its purchases of royalty oil from the Leases by a like amount (and shall do so to the extent its aggregate purchases of all Seller's royalty crude oil under all provisions of this Agreement exceed 150,000 barrels per day, averaged monthly) during the period it is purchasing oil pursuant to this Article 2.3. Such reductions shall be effected in accordance with the restrictions of Article 2.5 and subject to Buyer's obligation to buy and receive such oil as it has previously nominated. Oil purchased pursuant to this Article 2.3 shall be deemed oil out of the Leases for the purposes of Article 14.1(ii) only.

2.4 Buyer Option in the Event Certain Quantities Not Delivered. Upon and after the inception of operation of the Petrochemical Facility, in the event at any time and from time to time Seller has not made available for delivery to Buyer for more than two (2) consecutive months average daily quantities (averaged monthly) of royalty crude oil from the Leases equal to or in excess of 145,000 barrels per day, upon written request by Buyer, Seller shall immediately exercise any option which it as lessor may then possess, as directed by Buyer, under any other lease or leases to receive its royalty crude oil in kind rather than in value in order that Buyer has the ability to receive from Seller 150,000 barrels of oil per day, with such prior notification to the lessees under such

other leases as may be required thereunder; provided, however, that such option exercise by Seller shall only apply to seventy percent (70%) of the available royalty oil to be taken in kind and only as to such quantity of royalty crude oil as may be necessary to assure Buyer of the availability of 150,000 barrels per day in the aggregate. To protect and insure Buyer's right to receive at least 150,000 barrels of crude oil per day hereunder, after the date of execution hereof and for the full term hereof, all contracts for the sale of any royalty crude oil of Seller taken in kind (except for Seller's currently pending contract for the sale of oil out of the Leases to North Pole Refining Company and except for any renewal or renewals of the current contract of Seller with Tesoro for a like quantity of oil as is now being delivered under Seller's contract with Tesoro) shall contain a provision that Buyer shall possess a paramount right to call for and receive such royalty oil in the event deliveries to Seller from the Leases and available for sale and delivery to Buyer fall below 145,000 barrels per day pursuant to the provisions of this Article 2.4. Notwithstanding any other provisions contained in this Article 2.4, Buyer's option hereunder shall extend only to seventy percent (70%) of the royalty oil production of any field, lease, or contract in which Seller has an interest. Seller agrees that any lease agreements and agreements for the sale of royalty crude oil taken in kind hereinafter entered into will include the advance written notice of the purchaser, exchange partner or other recipient of the crude oil to the termination of any supplier-purchaser relationship which may be deemed to exist

with respect to the State of Alaska royalty crude oil for purposes of any mandatory crude oil allocation program under applicable law or regulations of the Department of Energy or its successors then in effect upon the call therefor by Buyer under the provisions of this Article 2.4. In order to effectuate the purposes of this paragraph Seller shall furnish Buyer such information as Buyer reasonably requests from time to time concerning leases of which the State is Lessor and possesses the right to receive its royalty in kind. At such time as the average daily quantity of crude oil available to be delivered pursuant to the provisions of Articles 2.1 and 2.3 reaches or exceeds 150,000 barrels per day for more than two (2) consecutive months after such option has been exercised by Buyer, Seller shall have the right to terminate Seller's taking of royalty crude oil in kind under the other leases as described above in this Article 2.4, upon prior written notice which is thirty (30) days more than the period necessary to provide legal notice to Seller's lessees of Seller's return to taking its royalty in value rather than in kind, but on not less than ninety (90) days' written notice to Buyer. Thereafter, Buyer shall again be entitled to exercise its rights under this Article 2.4 should the aggregate average quantity of 145,000 barrels of crude oil per day available to be delivered under Articles 2.1 and 2.3 not be attained for more than two (2) consecutive months. If for any reason Buyer's election or elections to receive oil under this Article 2.4, along with the other obligations of Buyer to receive oil under this Agreement result in Seller being required to take from its Lessees or the lessees referred to in Articles 2.3 and 2.4

more than 150,000 barrels per day, Buyer will take all such oil from Seller and shall advise Seller so that Seller may give notice to its Lessees to reduce the quantities of oil it is taking in kind pursuant to Buyer's nominations to an aggregate of 150,000 barrels per day.

2.5 Increases or Decreases of Crude Oil. Notwithstanding any other provision of this Agreement to the contrary, after the Date of First Delivery and from time to time thereafter, Buyer shall have the right upon notice to Seller to require Seller to exercise its right under the Prudhoe Bay Unit Agreement (and under any other lease the oil from which is being sold to Buyer under Articles 2.3 and 2.4 if the terms of such lease so permit) to increase or decrease, by the terms of said Unit Agreement (or lease), the quantity of royalty oil to be delivered to Seller, and the quantity of royalty oil to be delivered to and purchased by Buyer under this Agreement shall be so adjusted; provided, however, that the provisions of this Article 2.5 shall not operate or be construed to require that Seller deliver and sell to Buyer the percentage portions of Seller's royalty oil out of the Leases or out of the leases referred to in Articles 2.3 and 2.4 which Seller has expressly reserved as not to be sold and deliverable hereunder, and further provided that Seller shall not be required to deliver more than 150,000 barrels per day hereunder as an average daily delivery during any calendar month. In addition to the time for notice specified in the Prudhoe Bay Unit Agreement (or any such other lease), Buyer agrees to give Seller an additional thirty (30) days' notice of any nominations under this paragraph. In order to provide maximum administrative efficiency, nominations

under this Article 2.5 shall be made not more than once every thirty (30) days.

2.6 Delivery of TAPS Fill by Seller. Upon initiation of deliveries pursuant to Article 2.2, Seller in addition to all other quantities of crude oil deliverable hereunder shall deliver to Buyer on or prior to the Date of First Delivery a sufficient quantity of crude oil for Buyer to fulfill its tariff obligations to supply Trans-Alaska Pipeline System pipeline fill and storage tank bottom requirements. Buyer shall pay for such quantity of oil on the date of termination pursuant to the provisions of Article IX, X or XIV hereof, at the price stipulated in Article VIII as if such oil had been delivered to Buyer at the Point of Delivery forty-five (45) days prior to the said date of termination. In the event that Buyer, prior to the completion of the Petrochemical Facility, suspends its purchase of oil from the Leases after having initiated deliveries and after Seller has delivered the pipeline fill and storage tank bottom requirements as provided by this Article 2.6, Buyer shall pay for such quantity of oil as if it had been delivered at the Point of Delivery on the date Buyer suspended its purchases. Thereafter Seller shall again be obligated to provide pipeline fill and storage tank bottom requirements upon Buyer's reinitiation of deliveries of oil out of the Leases as provided by other provisions of this Article II.

ARTICLE III

POINT OF DELIVERY AND PASSAGE OF TITLE

3.1 Point of Delivery. Delivery of the oil sold from

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Seller to Buyer under Article 2.1 shall be made at the Seller's or Lessees' A.C.T. meter at the inlet inception point of the Trans-Alaska Pipeline System at Pump Station Number 1, Prudhoe Bay, Alaska. Delivery of any oil sold pursuant to the provisions of Articles 2.3 and 2.4 shall be at the same point of delivery that such oil is delivered to Seller by the lessee paying such oil as royalty oil in kind to Seller. Delivery under this Article 3.1 may be made at such other point or points of delivery as may be mutually agreed between Buyer and Seller. The Point or Points of Delivery set forth in this Article 3.1 shall hereinafter be referred to as the "Point of Delivery" or "Points of Delivery."

3.2 Passage of Title. Title to the oil to be sold hereunder shall pass from Seller to Buyer upon delivery.

3.3 Buyer's Responsibility. Buyer shall be responsible for the oil to be sold hereunder after passage of title hereunder. Buyer shall indemnify and hold Seller harmless from and against any and all claims, costs, damages, expenses or causes of action as a result of any loss, injury or damage incurred by any party as a result of any transaction or event which relates to the crude oil after title thereto has passed to Buyer. Buyer shall make all necessary arrangements for transporting the oil sold hereunder from the Point of Delivery to the Petrochemical Facility.

ARTICLE IV

REPRESENTATIONS AND OBLIGATIONS OF BUYER

Buyer represents, warrants and agrees that:

4.1 Good Standing. Buyer is and at all times hereunder

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will remain a corporation qualified to do business in, and in good standing with, the State of Alaska.

4.2 Construction of a Petrochemical Facility in the State of Alaska.

4.2.1 Construction Obligations. In consideration of the obligations assumed by each party herein, Buyer will proceed with reasonable diligence to design, construct, start up and thereafter initiate operation of a petrochemical manufacturing facility with fuels refining capacity in the State of Alaska. Such facility shall include facilities for the manufacture of energy fuels, aromatics, olefins and petrochemical derivatives of such basic feedstocks, and will include "offsite" facilities such as power supply, water supply, port facilities and administration buildings. Final process configuration and production rates of the various products listed above will be determined by (i) marketing considerations based on sales contracts for the products and (ii) process optimization of the overall facility design to produce the desired products in the most effective manner. Variations in process optimization will occur throughout the anticipated life of the facility. Such facilities shall be hereinafter referred to as the "Petrochemical Facility."

4.2.2 Siting of Petrochemical Facility. Buyer has chosen several preferred sites for the location of its Petrochemical Facility. Buyer shall notify the Commissioner no later than six (6) months after the Effective Date which site it has chosen (and the reasons for its choice of such site in reasonable detail), which such

site shall be subject to the approval of the Commissioner within ninety (90) days after receipt of notice by Seller of Buyer's choice of site. In making his decision, the Commissioner shall consider, among other things, the desires of the people who live in the immediate surroundings of any proposed site. Failure of Buyer to receive written reply from the Commissioner within such ninety (90) day period shall be deemed an approval of the site selection; provided, however, that such approval shall in no manner diminish or alter Buyer's obligation to obtain all requisite state and federal permits, licenses and applications or to comply with other applicable laws or regulations. In the event the Commissioner disapproves a proposed site, Buyer shall resubmit with additional pertinent information its original proposed site or shall propose an alternate site to the Commissioner within ninety (90) days from the date Buyer receives notice of disapproval. Resubmissions or submissions of alternate sites shall continue in like manner until a site is approved by the Commissioner. Or until ALPET6 cancels contract after two site submissions under 10.3.

4.2.3 Progress Reports by Buyer. From the Effective Date and until the conditions stated in Articles 10.2(1) through 10.2(3) have been satisfied, on or before the twentieth (20th) day of each month, the Buyer shall furnish the Commissioner a written progress report as of the end of the preceding calendar month describing compliance with the requirements of such Articles, the engineering, design and construction activities of Buyer with respect to the Petrochemical Facility, progress in the marketing of the products therefrom, and the proposed financings and scheduled expenditures of the Buyer. After fulfillment of all the conditions stated

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in Articles 10.2(1) through 10.2(3) and until all the conditions stated in Articles 10.2(4) through 10.2(9) have been satisfied, Buyer shall furnish like progress reports (also to be on the twentieth (20th) day of the month) each calendar quarter as of the end of the calendar month immediately preceding the month in which the report is made, beginning on the twentieth (20th) day of the third month next following the month during which the conditions under Articles 10.2(1) through 10.2(3) were fulfilled. Such reports, or portions thereof, shall be held confidential as requested by Buyer to the extent permitted by law.

4.3 Production of Energy Fuels for Intrastate Use. In order to provide fuels for distribution within the State of Alaska, Buyer shall design and construct the Petrochemical Facility to include a capacity to process 30,000 barrels of crude oil per day into energy fuels. If Buyer does not utilize the royalty oil sold and delivered hereunder, or traded or exchanged oil, in the Petrochemical Facility, then it shall utilize its best efforts to assure that at least 30,000 barrels per day of said royalty oil will be processed instate for production into energy fuels for intrastate distribution and sale, unless such processing would be surplus to the then prevailing intrastate domestic and industrial needs.

4.4 Establishment of Charitable Foundation. Buyer covenants and agrees to establish the Alaska Endowment Trust, the purpose of such trust being to further the social, educational, cultural and environmental conditions in the State of Alaska. The

Alaska Endowment Trust shall be established under the terms of a trust instrument proposed by Buyer and approved by the Governor of Alaska and Alaska Legislature; the trust corpus shall be administered by a Board of Trustees unaffiliated with Buyer. Trustees shall be appointed by the Governor of Alaska and confirmed by the Alaska Legislature. The corpus of the Alaska Endowment Trust shall be created from contributions by Buyer of amounts equal to five percent (5%) of the net after-tax profits, as hereinafter defined, realized from the operation of the Petrochemical Facility and sale of fuels and petrochemical products produced from the Petrochemical Facility. Each such annual contribution shall be paid on or before July 1 of each year based upon the net after-tax profits of the immediately preceding calendar year, the first such year of measurement to commence on January 1 next following ten (10) years after the Petrochemical Facility is completed, as measured by the delivery of the certificate of completion and operability by the prime contractor of Buyer in charge of construction of the Petrochemical Facility or sixteen (16) years after the Effective Date, whichever is earlier. "Net after-tax profits" shall mean the net income of Buyer prior to deduction or accrual of amounts payable under this Article 4.4 and shall be determined in accordance with generally accepted accounting principles applied on a consistent basis after deduction for all taxes which would have been provided for in the financial statements of Buyer for the year but for the payment of the amounts payable under this Article 4.4. Since the parties

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have assumed that payments under this Article 4.4 will be deductible as an expense for purposes of any tax imposed on the income of Buyer, in the event any taxing authority does not permit such deduction, the amount payable hereunder shall be adjusted to reflect such non-deductibility. Charges made by or to any Affiliate shall be reasonable and shall not exceed those charges which would have been made in arm's length bargaining with an unaffiliated party in light of all the circumstances of the transaction, including the length of term of any contracts, financing terms and any other direct and indirect benefits offered or received. All sales between Buyer and any Affiliate shall be at a fair market price or value for such goods or services in light of all the circumstances, including the length of term of any contractual relationship, financing terms and any other direct or indirect benefits offered or received.

ARTICLE V

REPRESENTATIONS AND OBLIGATIONS OF SELLER

Seller represents, warrants and agrees that:

5.1 Seller's Royalty Oil. Pursuant to the Leases and the leases presently in effect and referred to in Article 2.4, Seller has the right to take its royalty in kind (amount), which royalty oil it represents is at least twelve and one-half percent (12-1/2%) of any crude oil production removed or sold from the Leases, unless otherwise described in Exhibit "A".

5.2 Title. Seller hereby warrants good and marketable title to the oil sold by it hereunder and its right to sell the same,

and warrants that all such oil is owned by Seller free from all liens, encumbrances and adverse claims.

5.3 Storage of Oil. Under Paragraph 13 of the Lease Contracts, Seller may be entitled, under certain conditions, to storage of Seller's royalty oil from Lessees free of charge. Seller hereby licenses to Buyer its storage rights, if any, under the Leases (and under any other leases the oil from which is being sold to Buyer pursuant to Articles 2.3 and 2.4) effective upon the Date of First Delivery, to the fullest degree permissible under the Lease Contracts and to an extent proportionate to the proportion of Seller's royalty oil being delivered hereunder. Seller further agrees that it will aid and work with Buyer to resolve any uncertainties or ambiguities concerning Seller's right to storage under the Lease Contracts, including the institution and pursuit of litigation at Buyer's cost to clarify Seller's legal rights of storage under said Paragraph 13. Buyer and Seller agree that their mutual objective shall be to maximize the Seller's and Buyer's rights to receive storage of the oil from the Lessees. Notwithstanding anything stated herein, Seller does not warrant that it possesses any right or rights to storage under the Lease contracts or any other leases. Buyer agrees that any failure to obtain storage hereunder from the Lessees shall not relieve Buyer of its obligations under Article 10.2. Buyer will indemnify Seller and hold it harmless against all claims, costs, loss or liabilities arising from Buyer's use of said storage facilities or rights.

5.4 Covenant to Aid in Obtaining Governmental Permits. In order to construct the Petrochemical Facility, Buyer must obtain numerous permits, licenses and authorizations from state, federal and other governmental authorities. Seller agrees to utilize its best efforts to support, lend aid and facilitate the grant or approval of Buyer's applications for such permits, licenses and authorizations; provided, however, that the obligations stated herein shall not require Seller to support, lend aid or facilitate the grant or approval of any permits, licenses and authorizations which do not comply with applicable rules, regulations or laws, and provided further that Seller's obligations herein shall not require Seller to waive, rescind, modify or otherwise alter (either in substance or procedure) any of Seller's regulatory responsibilities. Seller, acting through the Commissioner, within thirty (30) days after the Effective Date shall appoint a state official who shall act as Seller's coordinator for the purpose of facilitating the granting of permits by Seller and to act as a liaison officer for Buyer and Seller with the federal government. Such designation may be changed from time to time by the Commissioner.

5.5 Delivery of Information to Buyer. Seller shall deliver to Buyer without cost to Seller (unless any costs to Seller be indemnified by Buyer) within thirty (30) days after the Effective Date:

(i) the most recent report it possesses or can obtain from third parties concerning the volume of hydrocarbons originally in place and the portions or fractions thereof which will be recovered from the Prudhoe Bay unit reserves, accompanied by any related studies or data pertaining to such report;

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(ii) the most recent anticipated production schedules of oil, solution gas, gas cap gas and condensate in its possession or obtainable from third parties out of the Prudhoe Bay unit by year; and

(iii) the most recent information, projections or estimates in its possession or obtainable from third parties of anticipated crude oil discovery and production in Alaska during the term of this Agreement.

During the term of this Agreement, as reasonably requested by Buyer in writing, Seller shall furnish updated information pertaining to Subparagraphs (i) through (iii) of this Article 5.5. Certain information and documents, including but not limited to well logs and related production data pertaining to the Leases and other leases referred to in Articles 2.3 and 2.4 may be required by law or regulation to be held confidential by Seller, its representatives and agents, and such documents shall not be required to be delivered hereunder. Seller understands and acknowledges the importance of reports taken from such data in securing financing for the Petrochemical Facility, and Seller agrees to use its best efforts to obtain and furnish to Buyer all such relevant data and reports as requested by Buyer. Seller agrees to retain, at Buyer's cost, independent consultants acceptable to Buyer to review confidential data, to prepare such updated reports and to state such opinions as may be reasonably requested by and furnished to Buyer to the extent permitted by applicable law and regulation. Seller's obligations under this section are for the purpose of aiding Buyer in obtaining up-to-date information, some or all of which may have been furnished to Seller by third parties; accordingly, Seller does not, by provid-

ing Buyer with the information specified in Subparagraphs (i) through (iii), warrant or represent the accuracy of such information, nor does Seller obligate itself to attempt in any way to bring about the conditions or projections contained in the information provided.

ARTICLE VI

QUALITY

6.1 Standard. The oil to be delivered by Seller to Buyer at the Point of Delivery hereunder shall be the same quality as the oil delivered by the working interest owners from the Leases and the leases. Except for the foregoing, Seller does not warrant, represent or guarantee, either expressly or impliedly the quality, merchantability, fitness for use, or suitability for any particular use or purposes, or otherwise of any oil to be delivered to Buyer under this Agreement. There are no warranties, representations or agreements concerning the quality of the oil which extend beyond the description of the oil in this Article VI.

ARTICLE VII

MEASUREMENTS AND TESTS

7.1 Testing Standards and Procedures. The quantity and quality of the crude oil sold and purchased from the Leases shall be determined at Lessees' A.C.T. meters at Pump Station One, Prudhoe Bay, Alaska. The quantity and quality of the crude oil sold and purchased from the other leases shall be determined at the Lessee's point of delivery. All measurements hereunder shall represent one hundred percent (100%) volume, consisting of United States barrels of forty-two (42) gallons, the quantity and gravity of which shall be adjusted to a temperature of sixty degrees (60°) Fahrenheit. Full deduction

shall be made for all basic sediment and water content according to the ASTM Standard Method then in effect. Unless agreed otherwise between Buyer and Seller or set forth herein, procedures for measuring and testing and for metering the crude oil shall be completed in accordance with standard oil field practices. Procedures for metered deliveries under the Leases shall be in accordance with accepted oil field practices in effect at Prudhoe Bay, Alaska. At the direction of Buyer, Seller shall direct the Lessess or lessees to test the accuracy of their measuring equipment if and to the extent that the provisions of the Prudhoe Bay Unit Agreement or any other agreement between Seller and Lessees or lessees permit Seller to make such request. Notice of the time and nature of each test of Lessees' or lessees' measuring equipment shall be given by Seller to Buyer sufficiently in advance to permit convenient arrangement for Buyer's representative to be present. Tests and adjustments shall be made in the presence of representatives of Buyer if present at the time scheduled for such test and adjustment. At Buyer's election and subject to obtaining the permission of any necessary third parties, Buyer may also install equipment to measure or gauge all oil received by Buyer hereunder at the Point of Delivery, and Buyer shall bear the entire acquisition, calibration, maintenance and operating cost of any such loading, measuring or testing equipment required by Buyer.

7.2 Delivery of Crude Oil Samples by Seller. Upon reasonable request by Buyer, Seller at its cost shall utilize its best efforts to aid Buyer in obtaining a representative sample of one barrel of crude oil taken at Valdez, Alaska, in order for Buyer

to perform an assay to analyze the composition, gravity, sulphur content and other characteristics of such crude oil sample. If any sample of the oil is delivered to Buyer, there is no representation or warranty by Seller that any other oil delivered hereunder will conform to the sample, it being understood that Seller will deliver only such oil as shall be delivered to it by the Lessees or lessees under the Leases or leases. Seller shall provide Buyer copies of all other assays obtained or received by it during the term thereof.

ARTICLE VIII

PRICE

8.1 Price.

8.1.1 Price of Oil Delivered Out of the Leases. As to oil sold and delivered hereunder out of the Leases, the price to be paid by Buyer to Seller shall be equal to the sum the Seller would have received from the Lessees had Seller received its royalty in value instead of taking the quantity of royalty oil delivered hereunder as its royalty in kind (amount). Seller and Buyer recognize that the method and basis of computing the royalty due Seller from Lessees under the Leases is currently a matter of dispute and litigation among the Seller and its Lessees, said litigation being entitled State of Alaska, et. al. vs. Amerada Hess Corp. et al., (No. CA 77-847, Superior Court of the State of Alaska, First Judicial District at Juneau). Pending resolution of said dispute among Seller and Lessees, by judicial decision or settlement in the above-

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referenced case, the in value royalty under the Leases, and therefore the price hereunder, shall be computed in accordance with Exhibit "B", attached hereto and by reference made a part hereof. After such time as said dispute shall be resolved among Seller and its Lessees, the parties hereto will be bound by the terms of such resolution, judicial or otherwise. Seller and Buyer expressly recognize that adjustment in prices previously paid may be necessary following said resolution and said adjustment shall be duly made, with interest, pursuant to the applicable provisions of Article IX. Any settlement agreement which agrees to the imposition of costs which are reimbursable by Buyer to Seller under Article 8.2, however, shall not be final and binding upon Buyer, unless Buyer has consented in advance to such settlement.

8.1.2 Price of Oil Sold Under Article 2.3. Oil sold pursuant to the provisions of Article 2.3 shall be the same lower price on the same terms and conditions as Seller is proposing to offer such oil.

8.1.3 Price of Oil Sold Under Article 2.4. The price of the oil sold pursuant to the provisions of Article 2.4 shall be the greater of (i) the best and highest price offered by a bona fide offeror for a like quality and quantity of the crude oil to be produced from such lease out of which oil is being delivered; or (ii) a price equal to the sum Seller would have received from its lessee or lessees had Seller received its royalty in value instead of taking the quantity of royalty oil delivered hereunder as its royalty in kind (amount).

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8.2 Reimbursement of Certain Costs of Seller. In addition to the price stated in Article 8.1, Buyer shall also reimburse Seller for Seller's pro rata share of (i) any basic sediment and water removal costs if Seller is required to pay such costs as a result of Seller's election to take its royalty oil in kind; and (ii) any other direct costs reasonably incurred and paid by Seller which would not have been incurred by Seller had the Seller taken its royalty in value rather than in kind and if such costs under Article 8.2(i) and (ii) were not previously reflected in applicable computations of value for payments of royalty in value. Seller shall use its best efforts to minimize any such costs incurred by Seller by reason of Seller's taking royalty oil in kind; such best efforts shall include but not be limited to litigation in cooperation with Buyer, at Buyer's cost, to the extent necessary to contest the imposition of unwarranted or improper charges; provided, however, that Seller shall in no event be required to advocate legal positions or adopt legal strategies which it, in its discretion, deems contrary to its own interests, in any such litigation. Seller at this date does not know of any potential costs to be incurred by it as a result of its taking in kind rather than in value other than the costs stipulated in Article 8.2(i) above.

8.3 Minimum Taking in Value by Seller. In order to facilitate the establishment of prices under Article 8.1 Seller agrees at all times during the term of this Agreement to take and receive in value rather than in kind the minimum number of barrels per day required to obtain a report of the in-value price from each Lessee.

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8.4 Federal Price Regulation. In the event a maximum price is established by the federal government during the term of this Agreement which applies to the royalty oil and which is lower than the prices established under this Article VIII above, then Buyer shall pay the Seller that maximum price for royalty oil delivered to Buyer, but only during such period such maximum price is in effect.

ARTICLE IX

PAYMENTS AND ACCOUNTING

9.1 Billing. Seller shall furnish Buyer monthly, on or before the tenth (10th) business day of each month after the first full month of delivery of crude oil, a statement of account of all crude oil delivered through and measured at the Point of Delivery during the immediately preceding month according to the best information available to Seller, the price or prices applicable thereto according to the best information available to Seller, the basis for computation of the applicable price or prices in full detail and the total net amount due. Seller shall render its billings to Buyer based upon the values, receipts, costs and computations reported by the Lessees to Seller. Seller shall thereafter adjust its initial billings pursuant to Article 9.5. Buyer and its authorized agents shall be permitted access during reasonable business hours to Seller's books and records pertinent to this Agreement to determine the correctness of the billings of Seller to the extent not contrary to law.

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9.2 Payment. Buyer shall make payment on or before the twenty-fifth day of the calendar month in which such statement is rendered or fifteen (15) days after rendition of the invoice called for in Article 9.1, whichever is later, by direct wire transfer of federal reserve funds through the Federal Reserve Bank wire transfer system to the following address or such other address as Seller may designate upon seven (7) days' prior written notice:

Bank of America, NT & SA
San Francisco, California
Securities Department 3255
Credit to: State of Alaska
Investment Account

All other payments to be made under this Agreement shall be paid in the same manner. If payment is to be made on a Saturday, Sunday or legal holiday under the preceding provisions hereof, payment shall be made on the next following business day.

9.3 Billing Disputes. Should any portion of the account furnished to Buyer by Seller be disputed in good faith, Buyer and Seller agree to mutually arrive at a fair and equitable resolution of such dispute, if possible, and Buyer agrees to pay the amount so determined to be due to Seller within fifteen (15) days after such resolution. Buyer shall pay for such amounts as it does not in good faith dispute in accordance with the provisions of this Article IX.

9.4 Late Payment Charge. If Buyer fails to make timely payment to Seller of any amount due under this Agreement, including

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any payment delayed by a bona fide dispute which is later determined to be validly owing, or if Buyer is required to pay and does pay any amount which is later determined not to be validly payable to Seller, interest shall accrue and be payable on said sum from the date when such payment was due or was paid, as the case may be, until the same is paid or repaid, at the lower of (i) a rate per annum equal to the prime rate then being charged by Chemical Bank of New York, New York, plus one and one-quarter percent (1-1/4%) per annum, or (ii) the maximum lawful rate of interest per annum which may be charged to Buyer under the laws of the State of Alaska.

9.5 Adjustments to Billings. Each month Seller shall adjust its statement of accounts to reflect the actual amounts delivered and the price or prices applicable thereto. Seller shall from time to time adjust its prior billings to reflect adjustments necessitated as a result of (i) a final judgment or settlement entered in certain pending litigation between Seller and the Lessees styled State of Alaska, et al. vs. Amerada Hess Corporation, et al. No. CA 77-847, in the Superior Court of the State of Alaska, First Judicial District at Juneau; (ii) adjustments necessitated as a result of the filing with the Seller by the Lessees of more current reports applicable to the billing period in question; (iii) actual adjustments necessitated as a result of changes to values, receipts, costs and computations previously reported by the Lessees and utilized by Seller as a basis for billing under Article 9.1, if such adjustments are based upon actual later severance tax or royalty

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oil payments by or refunds to the Lessees; or (iv) adjustments required as a result of clerical or arithmetical errors in the billings of Lessees or of Seller; provided, however, that no adjustments, whether credits or debits, under Articles 9.5(ii) through 9.5(iv) shall be made by Seller or demanded by Buyer more than twelve (12) months after billing except as to matters which are the subject of (x) pending litigation by either party, (y) pending regulatory proceedings (or appeals thereof) whether or not Seller or Buyer is a party thereto, or (z) bona fide audits by Seller which audits have been terminated or completed by Seller within twelve (12) months after initiation of same.

Due to the potentially large sums of money involved, any adjustments to any billing under the provisions of this Article 9.5 by Seller made more than sixty (60) days after such billing was initially rendered shall be paid to or refunded by Buyer or Seller over the same period over which such adjustments accrued or thirty-six (36) months, whichever is longer, beginning with the first payment next following the date such adjustment has been determined; provided, however, no such payment extension permitted hereunder shall extend beyond the term stipulated in Article 10.1, and accordingly the full balance of any unpaid adjustments shall become due and payable on the termination date hereof.

9.6 Cancellation in Event of Non-Payment. Except for amounts disputed in good faith, should Buyer fail to make any payment due to Seller under this Agreement (i) within sixty (60) days

from the date said payment is due or (ii) within thirty (30) days from the date that Seller gives written notice of non-payment to Buyer in the manner provided in Article 16.1 hereinbelow (except that said notice shall be directed to the attention of the President of Buyer), whichever occurs earlier, this Agreement shall automatically be cancelled.

ARTICLE X

TERM

10.1 Term. Subject to the further provisions of Articles 10.2 and 10.3 this Agreement shall become effective on the Effective Date and except as extended by Article XV hereof shall continue and remain in force and effect for a period of twenty-seven (27) years from the Effective Date.

10.2 Termination by Seller. This Agreement shall terminate upon failure of Buyer to take each and every one of the following actions within the time specified for each, including any time extensions provided for in this Article 10.2:

(1) Within six (6) months after the Effective Date:

(a) Actually expend at least Two Million Dollars ($2,000,000.00) in Total Project Costs.

(b) Negotiate with interim lenders and obtain commitment to provide funds deemed necessary by Buyer for organizational costs and initial design costs of the Petrochemical Facility.

(c) Commence planning for optimization of design of the Petrochemical Facility.

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(d) Notify Seller of Buyer's final selection of site location, such notification to be accompanied or preceded by site studies and recommendations based on preliminary engineering, including compression tests and cost estimates of infrastructure, offsite and marine facilities.

The Commissioner may extend the above six (6) month period as to Articles 10.2(1)(b), (c) and (d) thirty (30) days, but only in the event Buyer has, prior to such extension, fulfilled the requirements of Article 10.2(1)(a).

(2) Within twelve (12) months after the Effective Date:

(a) Actually expend at least Three Million Dollars ($3,000,000.00) in Total Project Costs.

(3) Within eighteen (18) months after the Effective Date:

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least Ten Million Dollars ($10,000,000.00) in Total Project Costs.

(b) Negotiate sale terms with prospective purchasers of products from the Petrochemical Facility; delineate product requirements, production ratios and quantities for the range of products to be produced from the Petrochemical Facility; and draft contracts for the sale of products from the Petrochemical Facility.

(c) Enter into contracts for the sale of at least seventy percent (70%) of the product output from the Petrochemical Facility.

(d) Obtain or cause contractually bound third parties to obtain written commitments to lend or invest at least One Billion Five Hundred Million ($1,500,000,000.00) in the aggregate for payment of Total Project Costs.

(e) Obtain a commitment or commitments for interim financing for the construction of the Petrochemical Facility.

(f) Complete and file an Environmental Impact Assessment on the Petrochemical Facility.

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What is the legal definition of this?

(g) Complete and file all material state, local and federal permit applications.

(h) Complete plant design and optimization necessary to obtain a definitive project cost estimate ("definitive" meaning a cost estimate containing no more than fifteen percent (15%) variance in anticipated costs).

The Commissioner may extend the above eighteen (18) month period as to any one or more of the criteria or events stated in Articles 10.2(3)(a) through (h) six (6) months.

(4) Within twenty-four (24) months after the Effective Date:

Amendment No. 2

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least One Hundred Million Dollars ($100,000,000.00) in Total Project Costs.

The Commissioner may extend the above twenty-four (24) month period as to the attainment of the criteria stated in Article 10.2(4)(a) six (6) months.

(5) Within thirty (30) months after the Effective Date:

(a) Execute definitive documents relating to the long-term loan of funds for the Petrochemical Facility.

(b) Commence construction of the Petrochemical Facility.

The Commissioner may extend the above thirty (30) month period as to one or more of the events or criteria stated in Articles 10.2(5)(a) and (b) above six (6) months.

(6) Within thirty-six (36) months after the Effective Date:

Amend. No. 2

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least Six Hundred Million Dollars ($600,000,000.00) in Total Project Costs.

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The Commissioner may extend the above thirty-six (36) month period as to the attainment of the criteria stated in Article 10.2(6)(a) six (6) months.

(7) Within forty-eight (48) months after the Effective Date:

Amendment No. 2

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least One Billion Dollars ($1,000,000,000.00) in Total Project Costs.

The Commissioner may extend the above forty-eight (48) month period as to the attainment of the criteria stated in Article 10.2(7)(a) six (6) months.

(8) Within sixty (60) months after the Effective Date:

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least One Billion Two Hundred Million Dollars ($1,200,000,000.00) in Total Project Costs.

The Commissioner may extend the above sixty (60) month period as to the attainment of the criteria stated in Article 10.2(8)(a) nine (9) months.

(9) Within seventy-two (72) months after the Effective Date:

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least One Billion Five Hundred Million Dollars ($1,500,000,000.00) in Total Project Costs.

The Commissioner may extend the above seventy-two (72) month period as to the attainment of the criteria stated in Article 10.2(9)(a) twelve (12) months.

(10) In addition to the periods of time which the Commissioner may extend the periods for performance of the criteria stated in this Article 10.2, the Commissioner may further extend the time for performance of any of the criteria stated in Article 10.2(1) through 10.2(9) for that period of time necessary to permit the Commissioner and the Alaska State Legislature to consider an amendment or modification of this Agreement, particularly of the provisions contained in Article 10.2. Such time extension shall not, however, extend beyond a period of time in excess of ninety (90) consecutive days during which the Alaska State Legislature is in session, nor shall such time extension include a consecutive period of less than ninety (90) days during which the Alaska State Legislature is in session without the prior written consent of Buyer.

10.3 Termination by Buyer. In the event that Buyer after expending all reasonable efforts fails to obtain the necessary binding commitments from interim and permanent lenders for all the funds necessary to permit construction of the Petrochemical Facility under a loan or loans providing for repayment of such loans during the life of this Agreement or fails to obtain site approval from the Commissioner after submitting at least two sites to the Commissioner pursuant to Article 4.2.2, Buyer may thereupon elect to cease design and construction of the Petrochemical Facility and terminate this Agreement without liability to either party by giving Seller notice of termination; on the thirtieth (30th) day after the giving of such notice this Agreement shall terminate, and Buyer shall deliver to Seller all documents and data pertinent to the Petrochemical Facility (or

copies thereof) in its possession, including engineering and site selection information as may be reasonably requested by Seller.

ARTICLE XI

APPROVAL OF CONTRACT BY STATE OF ALASKA AND EFFECTIVE DATE

This Agreement shall take effect on the date on which this Agreement has been approved by concurrent resolution of a majority of each house of the Tenth Alaska State Legislature ("Effective Date").

ARTICLE XII

SECURITY

12.1 Creation of Security Interest. To secure payment of all amounts due Seller for oil sold hereunder, Seller retains and Buyer hereby grants a purchase money security interest in all of the oil delivered and to be delivered to Buyer hereunder and in all oil obtained by Buyer in exchange for oil purchased hereunder; the products made or processed from any such oil, including all substances, if any, commingled therewith, or added thereto; and in the proceeds of the sale of any such oil or products, including the accounts receivable of Buyer arising from its sales of oil or products manufactured therefrom. The security interest shall attach to the oil at the time and Point of Delivery but shall terminate as to oil or products therefrom sold to a bona fide purchaser of Buyer in the ordinary course of Buyer's business but the said security interest shall attach to the accounts receivable arising therefrom. Notwithstanding the provisions of this Article 12.1, Seller agrees that (i) the security interest in the oil shall not attach at the time and Point of Delivery but instead at the time the oil arrives and is delivered to Buyer at the outlet flange measuring device of the Valdez, Alaska terminal facility of the Trans-Alaska Pipeline System ("TAPS") as to any oil shipped under any tariff pertaining to the TAPS which contains a prohibition against carriage of oil on which a lien of a party other than the carrier thereof exists or which grants to any carrier the right to reject carriage of oil on which such a lien

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exists if Buyer has provided Seller a bond, letter of credit, marketable securities or other security, as described in Article 12.2 in an amount or of a value equivalent to the value of oil of Buyer in the TAPS on which no lien of Seller exists, unless Seller or Buyer has obtained and furnished for Buyer evidence that such prohibition or right of rejection has been effectively terminated or waived and is unenforceable; and (ii) no lien shall attach to any oil or products produced therefrom or accounts receivable created from the resale thereof as to which payments to Seller have been made for the account of Buyer if (a) such payments are not derived from the sale of property otherwise subject to the security interest of the Seller and (b) such payments are secured or are to be secured by such oil, the products produced therefrom or the accounts receivable created from the resale thereof. Seller agrees that any document filed to perfect Seller's purchase money security interest described in this Article 12.1 shall contain an exclusion to the effect set forth in the next preceding sentence. Buyer agrees that it shall not agree, or consent to, or permit the filing of, any lien or security interest in the oil other than the lien of a TAPS carrier nor shall it transfer title thereto prior to its arrival and delivery to Buyer at the outlet flange measuring device of the Valdez, Alaska terminal facility of the TAPS or prior to the attachment of Seller's security interest thereto upon such delivery. Buyer further agrees that it will not grant or consent to any security interest in the oil or other security in favor of any third party unless such third party agrees in writing prior thereto that such security interest is subordinate to the security interest of the Seller, except as provided otherwise in Article 12.1(ii). Buyer agrees to execute and file all documents necessary to perfect Seller's said security interest in the oil, proceeds from the oil and accounts receivable referred to above. "Proceeds of the sale" shall include proceeds derived from insurance or other payments resulting

from damage to or destruction of the oil or other property covered by the security interest. To secure such payment Buyer shall cause all policies of insurance on the oil or other property to which the security interest attaches to name the Seller as coinsured as its interests may appear.

12.2 Alternative Security. In lieu of the security interest provided in Article 12.1, Buyer may provide alternative security in the form of a bond attached hereto and made a part hereof as Exhibit "C", executed by the Buyer, as principal, and a corporate surety agreed to by the Commissioner and authorized to write such bonds in the State of Alaska, as surety for a sum which shall substantially reflect the amounts owed by Buyer to Seller plus an amount equal to the value of any oil delivered by Seller to Buyer and not yet billed pursuant to Article IX; provided that whenever Seller has reasonable grounds for asserting and does assert any claims against Buyer in excess of the penal sum of the bond of Buyer then in effect hereunder, Buyer after being so requested by Seller shall either increase the penal sum of such bond to an amount reasonably sufficient to cover the claim of Seller and all expenses which may be incurred by it in connection therewith or shall furnish other security satisfactory to Seller, such as a renewed security interest in the oil or a portion thereof sold hereunder, regardless of whether the Buyer does or does not recognize the validity of the Seller's claim (so long as reasonable grounds for asserting such claim exist); provided further that the Buyer may at any time and from time to time deposit and maintain with the Commissioner at Buyer's expense in lieu of any such bond, either (i) an irrevocable letter or letters of credit addressed to the Commissioner issued by a state or national banking institution of the United States which is a member of the Federal Deposit Insurance

Corporation and has an aggregate capital and surplus of not less than $50,000,000, or (ii) marketable securities which are approved by the Commissioner, and which shall be transferable by the Commissioner or by delivery by stock power attached or other means, such letter or letters of credit to be in an aggregate amount, or such marketable securities to be of an aggregate then fair market value, of not less than the amount then required for Buyer's bond hereunder any such letter or letters of credit and marketable securities, together with any proceeds thereof, to be held by the Commissioner for the security and benefit of the Seller; and either of (i) or (ii) to be in form and substance approved by the Seller. The amount of said letter or letters of credit or marketable securities shall be subject to increase in the same manner that the face amount of the bond is subject to increase. If marketable securities are so furnished, other marketable securities which meet the requirements of this Subparagraph (a) may be substituted at any time and from time to time for any previously furnished marketable securities, and the marketable securities so furnished shall be increased if at any time the fair market value of the securities then held by the Commissioner is less than, or may be reduced if the fair market value thereof exceeds, the amount of the bond then required of Buyer hereunder, or (iii) security which in the opinion of the Commissioner is of equal value to the security above described.

what does this refer to?

ARTICLE XIII

TRADE OR EXCHANGE OF CRUDE

13.1 Subject to the provisions of Article 4.3 hereof and the further provisions of this Article 13.1, Buyer may trade or exchange any or all of the royalty crude oil for other crude oil or products. No trade or exchange by Buyer shall reduce the price to be paid to Seller under Article VIII hereof, and any such trade or exchange shall be without cost or expense to Seller. Buyer agrees not to trade or exchange royalty oil with another party unless that party agrees to give Buyer written permission to terminate the trade or exchange relationship upon the termination of this Agreement. Buyer shall require of any trade or exchange partner specific acknowledgment of Buyer's obligations under Article 26.6 and written permission from Buyer's trade or exchange partner to terminate the trade exchange arrangement upon termination of this Agreement. Buyer shall also require of its trade or exchange partner that it agrees to include provisions similar to this section in contracts for the sale, trade or exchange of the royalty oil and that all subsequent purchasers and trade or exchange partners will do likewise.

ARTICLE XIV

DEFAULT

14.1 Default. If

(i) either party shall fail to perform any of the covenants or obligations imposed upon it by this Agreement, except when such failure shall be excused under the force majeure provisions of Article XV, or

(ii) for any period of six (6) consecutive months, beginning one (1) year after the Petrochemical Facility has initiated processing of crude oil into petrochemicals, and subject to the provisions of Article XV, Buyer fails to purchase in the aggregate at least one-third (1/3) of the crude oil which could be purchased by Buyer out of the Leases and the leases referred to in Article 2.4 during any calendar month, or

(iii) Buyer becomes insolvent or commits any act constituting an act of bankruptcy, or

(iv) Buyer voluntarily files an action under the United States Bankruptcy Act, or

(v) Buyer fails to obtain the dismissal of any involuntary bankruptcy proceeding filed against it under the provisions of the United States Bankruptcy Act within thirty (30) days of the filing thereof,

then and in any such event, the other party may, at its option and without waiving any other remedy for breach hereof, indicate such party's election to cancel this Agreement by notice in writing specifying in detail wherein the default has occurred. Except for the instances stipulated in Articles 14.1(iii) through (v) above, and except for payment by Buyer to Seller, which shall be governed by Article 9.6, the party in default shall have thirty (30) days from the receipt of such notice to remedy such default and to pay the other party for all loss or damage incurred as a result of such default and indemnify such party against future claims or loss arising out of such default. Upon failure of the defaulting party to remedy its breach within the time stipulated above, this Agreement may be cancelled by the non-defaulting party by service of written notice thereof upon the defaulting party. Any cancellation under Article 9.4 or this Article 14.1 [except Article 14.1(ii)] shall not

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prejudice the right of the party not in default to collect any amounts due it hereunder for any damage or loss suffered by it and shall not waive any other remedy to which the party not in default may be entitled for breach of this Agreement.

14.2 Disposition of Oil Upon Default, Cancellation or Termination. It is agreed that if Buyer shall for any reason fail to take the royalty oil hereunder as and when made available to the Buyer pursuant to Buyer's previous nominations, Buyer shall nevertheless pay Seller as though it had taken delivery of said royalty oil, unless Seller through an understanding with Lessees or the lessees referred to in Articles 2.3 and 2.4 is able to cancel delivery of the quantities called for in said nominations of Buyer. In the event of any cancellation or termination of this Agreement, whether under Articles 10.2 or 10.3, or because of default under this Article XIV or Article 9.6, Buyer shall have an obligation to continue to purchase Seller's royalty oil for up to seven (7) months following termination or cancellation of this Agreement in such quantities as Buyer has elected pursuant to the nomination procedure set forth in Article 2.5 in the six (6) months preceding termination of this Agreement, if Seller is required by the Lessees or the lessees under Articles 2.3 and 2.4 to accept delivery in kind for such period.

14.3 Materiality of Breach. No default or breach of, or failure of performance under, this Agreement shall be deemed to have occurred under this Agreement unless such default, breach or failure of performance is material or substantial under all the cir-

Not important
What about not meeting time frame under 15.2 (State's legal consultant)

cumstances or involves the non-payment of any sum due under this Agreement which is not the subject of a bona fide dispute.

ARTICLE XV

FORCE MAJEURE

15.1 Relief from Obligations. Except for Buyer's and Seller's obligations to make payment under this Agreement and except for Buyer's obligation to take oil nominated by it, neither party hereto shall be liable for any failure to perform the terms of this Agreement when such failure is due in whole or substantial part to a "force majeure" as hereinafter defined; provided, however, that if an event constituting a force majeure shall prevent substantial performance of a party's obligations hereunder in light of all the circumstances, so as to prevent the party not claiming force majeure from obtaining the benefit of its bargain for a period in excess of four (4) years, said party not claiming force majeure shall have the option to terminate this Agreement. Said option must be exercised before the force majeure ceases to exist. The aforesaid proviso shall not permit the Seller to terminate in the event the force majeure in question is based upon Buyer's inability to obtain requisite state permits, authorizations, or licenses if Buyer has exercised the due diligence required by Article 15.2(ix). Other remedies otherwise available for default or breach in the event of termination after such four year period shall not thereby be affected.

15.2 Definition of "Force Majeure". The term "force majeure" as employed in this Agreement shall mean (i) acts of God;

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(ii) strikes, lockouts or industrial disputes or disturbances; (iii) civil disturbances, arrests and restraint from rules or people; (iv) interruptions by laws, orders, rules, regulations, acts or restraints of any government or governmental body having proper jurisdiction; (v) acts of the public enemy, wars, riots, blockades, insurrections, mobilization; (vi) acts of vandalism or sabotage; (vii) shortages, scarcity or inability to secure labor, fuel, power, equipment or materials (including inability to secure materials by reason of allocation promulgated by authorized governmental agencies), (viii) inability or failure of contractors or subcontractors to perform, (ix) inability to obtain requisite federal, state or other governmental permits, authorizations, or licenses provided the party claiming force majeure has exercised due diligence in attempting to obtain such permits, authorizations or licenses; (x) inability to ship materials because of unavailability of shipping, docking or wharfage not within the reasonable control of the party claiming the existence of a force majeure; (xi) epidemics, landslides, lightning, earthquakes, fire, explosion, floods, washouts, storms, other unusual adverse weather conditions; (xii) breakdowns of machinery, equipment or lines of pipe; (xiii) freezing of wells, pipe lines or other equipment; (xiv) shutdowns necessary for making repairs or alterations to pipe lines or plants, mechanical failure, or the necessity of testing wells, machinery or lines of pipe as may be required by governmental authority or as may be deemed necessary by the testing party for the safe operation thereof whether or not

of the kind herein enumerated; or (xv) any other event or condition otherwise not reasonably within the control of the party claiming force majeure, whether or not similar to the enumerations of (i) through (xiv).

15.3 Effect of Force Majeure. Upon the occurrence and discovery of an event constituting force majeure, the party claiming that the event is a force majeure shall notify the other party hereto of its claim of force majeure. The party claiming the existence of a force majeure shall, so far as reasonably possible, attempt to remedy such event with due diligence, and the obligations of the disabled party to perform under this Agreement, insofar as they are affected by such force majeure, shall be suspended from the time such force majeure occurs and for so long as the disability so caused should have continued had the party claiming the existence of the force majeure met its remedial obligations under this Article 15.3, and for no longer. The settlement of strikes or lockouts or industrial disputes or disturbances shall be entirely within the discretion of the party having the difficulty, and the above requirement that any force majeure shall be remedied with due diligence shall not require the settlement of strikes, lockouts or industrial disputes or disturbances by acceding to the demands of any opposing party therein when such course is inadvisable in the sole discretion of the disabled party.

Is this standard language re discretion of the party having difficulty?

No need to worry about it.

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ARTICLE XVI

NOTICES

16.1 Notices. Any notice, request, demand or statement provided for in this Agreement must be in writing, and may be given by depositing same in the mail, addressed to the party to be notified, postage prepaid, and registered or certified, with a return receipt requested, or by delivery of same in person to such other party. Notice deposited in the mail in the manner hereinabove described shall be effective upon the expiration of seven (7) days after it is so deposited. Notice given in any other manner shall be effective only if and when received by the addressee. For purposes of notice the addresses of the parties hereto shall be as follows:

If to Seller:

State of Alaska
Commissioner of Natural Resources
Pouch "M"
Juneau, Alaska 99811

and
Commissioner of Revenue
Pouch "S"
Juneau, Alaska 99811

and
Director, Division of Minerals
and Energy Management
323 Fourth Street
Anchorage, Alaska 99501

If to Buyer:

Alaska Petrochemical Company
601 W. 5th Avenue, #320
Anchorage, Alaska 99501

and
Alaska Petrochemical Company
P. O. Box 6554
Houston, Texas 77005

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16.2 Change of Address. Each party may change its address for notice by giving of notice thereof in the manner hereinabove provided.

ARTICLE XVII

WAIVER

The failure of Seller or Buyer to insist upon strict performance of any provision hereof shall not constitute a waiver of, or estoppel against asserting, the right to require such performance in the future; a waiver or estoppel in any one instance shall not constitute a waiver or estoppel with respect to a later breach of a similar nature or otherwise; a course of performance established by a party shall likewise not estop the other party from complaining of a later breach similar in nature.

ARTICLE XVIII

RECORDS

18.1 Preservation of Records. Buyer and Seller will preserve and maintain all books, accounts and records relating to or arising out of the performance of this Agreement, including but not limited to, the planning, construction and operation of the Petrochemical Facility and the purchase or resale of the royalty oil and its refined products for a period of four (4) years. Buyer will also maintain and preserve all similar books, accounts and records of which it has possession belonging to those third parties with whom it contracts for the performance of various parts of this Agreement. Neither Buyer nor Seller shall be required to retain

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any records for more than six (6) years unless retention of such records is specifically required by applicable law or regulation. Buyer shall either maintain its records within the State of Alaska or make such records available to Seller at Buyer's principal office in the State of Alaska within thirty (30) days after written request therefor by Seller.

18.2 Inspection of Records of Parties. Buyer and Seller will accord to each other and to their authorized agents, attorneys and auditors during reasonable business hours access to any and all property, records, books, documents and indexes thereto directly relating to the Buyer's or Seller's performance of this Agreement and which are under the control of the party from which access is desired so that the other party may inspect, photograph and make copies of such property, records, books, documents and indexes thereto. Notwithstanding the foregoing, (i) Seller shall not be required to disclose any information, data or records which are required to be held confidential by applicable state law or regulation, and (ii) Buyer shall not be required to disclose any information, data or records containing trade secrets which Buyer or its Affiliates, contractors or subcontractors by contract with unaffiliated third parties have agreed to hold confidential. Seller shall notify Buyer of all information obtained, recorded or copied from Buyer's records in order that Buyer may evaluate the advisability of seeking that such information be held confidential by Seller under applicable law or regulation or under the provisions of this Article.

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18.3 Financial Statements. So that Seller may be fully informed with regard to Buyer's financial capabilities on an on-going basis, Buyer will provide Seller with a financial statement at quarterly intervals during any periods which Buyer is receiving delivery of oil under this Agreement from Seller. In addition, Buyer will provide Seller with year-end financial statements audited by an independent certified public accounting firm. Preparation of the financial statements shall be at Buyer's cost. Said statements shall be communicated to Seller in the manner provided in Article 16.1.

ARTICLE XIX

RULES AND REGULATIONS; SOVEREIGN POWERS; ENVIRONMENTAL REGULATION AND STANDARDS

19.1 Applicable Laws, Rules and Regulations. This Agreement and the covenants contained herein shall not be interpreted as a limit on the exercise by the State of Alaska of any of its sovereign or regulatory powers, whether inherent or as may be set forth by constitution, statute or regulation, to protect the environment, fish and wildlife, or the health, safety, general welfare, lives or property of the people of the State of Alaska. This Agreement is subject to all present and future valid laws, orders, rules and regulations of the United States, the State of Alaska, or any duly constituted agency thereof; provided, however, that this paragraph shall not be deemed a consent to any attempted alteration, amendment, termination or revocation of the contractual rights, obligations or duties of the parties hereto by the State of Alaska.

19.2 Compliance with State Rules and Regulation. Buyer

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shall comply with all valid and applicable laws and regulations with regard to maintaining the quality of the environment of the State of Alaska, the well-being of fish and wildlife of the State, and the health, safety and welfare of the citizens of the State of Alaska, in the construction of the Petrochemical Facility, the operation and maintenance of the Petrochemical Facility during the term hereof, and with respect to Buyer's purchase, refining and resale of the oil sold hereunder.

19.3 Compliance with Supplemental Environmental Standards. Buyer agrees to comply with the environmental protection standards set forth in Exhibit "D", whether or not such standards are required presently or in the future by applicable governmental law or regulation; provided, however, that the Commissioner of the Department of Environmental Conservation shall possess the power and authority to waive or eliminate any such standards upon a showing of reasonable cause, and provided further that the standards set forth in Exhibit "D" are supplemental to, and not substitutive of, any present or future laws or regulations applicable to regulation of the environment of the State of Alaska.

ARTICLE XX

GOVERNING LAW

This Agreement shall be governed by and construed in accordance with the laws of the State of Alaska, excluding any conflicts-of-law rule or principle which might refer such construction to the laws of another state or country.

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ARTICLE XXI

SEVERABILITY

If any of the terms and conditions of this Agreement are held by any court or governmental authority of competent jurisdiction to contravene or to be invalid under the laws of any political body having jurisdiction over the subject matter hereof, such contravention or invalidity shall not invalidate the entire Agreement. Instead, this Agreement shall be construed as if it did not contain the particular provision or provisions held to be invalid, the rights and obligations of the parties hereto shall be construed and enforced accordingly if feasible, and this Agreement shall thereupon remain in full force and effect.

ARTICLE XXII

AMENDMENT

This Agreement may be supplemented, amended or modified only by a written instrument duly executed by both the parties hereto after proper prior authorization, including approval by the Alaska Royalty Oil & Gas Development Advisory Board and the Alaska State Legislature. Buyer agrees that in the event Article VIII of this Agreement is subsequently amended so as to materially reduce the consideration paid to the Seller, directly or indirectly, for the royalty oil, said amendment will only be effective after it has been approved by a direct vote of the people of the State of Alaska.

ARTICLE XXIII

SUCCESSORS AND ASSIGNS

23.1 General Prohibition of Assignment. Except as otherwise permitted under Article 23.2 no assignment of this Agreement shall be made by either party without first obtaining the written consent of the other party. The Commissioner may grant such consent on behalf of Seller.

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23.2 Limited Right of Assignment. This Agreement shall bind and benefit the parties hereto and their respective successors and valid assigns, but no permitted conveyance or transfer of any interest of either party shall be valid until such other party has been furnished with written notice and a true copy of such conveyance or transfer and an assumption, if any, of this Agreement by such assignee. Either Buyer or Seller, or both, may assign its right, title and interest in, to and by virtue of this Agreement, including any and all extensions, renewals, amendments and supplements thereto to a trustee or trustees, individual or corporate, or to any lender or lenders, as security for bonds or other indebtedness, obligations or securities, without such trustee or trustees or lender or lenders assuming or becoming in any respect obligated to perform any of the obligations of the assignor, and if any such trustee or lender be a corporation, without its being required by the parties hereto to qualify to do business in the State of Alaska (but such trustee or lender shall be required to submit to the jurisdiction of the courts of the State of Alaska for matters relating to this Agreement), and no such assignment shall serve to relieve the assigning party of its obligations hereunder. Any assignment by Buyer pursuant to the next preceding sentence shall be subject to the prior written approval of the Commissioner of any such trustee or trustees or lender or lenders; provided, however, that on or after the date that all the conditions stated in Article 10.2(3) have been fulfilled, no such prior written approval shall be

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required and such assignment to such trustee or trustees or lender or lenders may be freely made. In the event any such trustee or trustees, lender or lenders, or their assignee shall foreclose upon or otherwise assume ownership rights in and to this Agreement, thereupon such trustee or trustees or lender or lenders and their valid successor and assigns (i) shall assume such rights and benefits as well as obligations and liabilities only upon written notice given by it or them to Seller, (ii) shall have the right to receive from Seller, without assuming any obligations or liabilities under this Agreement, except as expressed below in the last sentence of this paragraph, any money or property owed by Seller to Buyer under this Agreement as of the date of such foreclosure, (iii) shall have the right to sell or assign their ownership rights to this Agreement to any person, without the consent of the Seller if such person assumes the obligations of Buyer under this Agreement, and (iv) following such further sale or assignment, shall be relieved of any obligations or liabilities provided for under this Agreement. Nothing contained within this Article 23.2 shall operate so as (1) to terminate or subordinate Seller's security interest in oil, products, proceeds of the sale, (2) to cancel any obligation to provide security as set forth in Article 12.2, until money owed to Seller under this Agreement is paid.

ARTICLE XXIV

EQUAL EMPLOYMENT OPPORTUNITY

24.1 Discrimination. Buyer will not discriminate against

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any employee or applicant for employment because of race, color, religion, national origin, ancestry, age or sex. The Buyer will take affirmative action to insure that applicants are considered for employment, and that employees are treated during employment, without regard to their race, color, religion, national origin, ancestry, age or sex. Such action shall include, but not be limited to, the following: employment, upgrading, demotion, or transfer; recruitment or recruitment advertising; layoff or termination, rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Buyer agrees to post in conspicuous places, available to employees and applicants for employment, notices setting forth the provisions of this nondiscrimination clause.

24.2 Advertisement of Equal Employment Opportunity. The Buyer shall state, in all solicitations or advertisements for employees to work that all qualified applicants will receive consideration for employment without regard to race, color, religion, national origin, ancestry, age or sex.

24.3 Notices to Unions. The Buyer will send to each labor union or representative of workers with which the Buyer has a collective bargaining agreement or other contract or understanding a notice advising the labor union or workers' representative of the Buyer's commitments under this Article and shall post copies of the notice in conspicuous places available to all employees and applicants for employment.

24.4 Inclusion of Equal Employment Opportunity Provisions

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in Contracts and Subcontracts. The Buyer will include the provisions of Article 24.1 through 24.3 in its contracts pertaining to the construction and operation of the Petrochemical Facility and will require the inclusion of these provisions in every subcontract entered into by any of its contractors, so that such provisions will be binding upon each subcontractor of Buyer.

24.5 Cooperation with Agencies of Seller. The Buyer agrees that it will fully cooperate with the office or agency of the State of Alaska which seeks to deal with the problem of unlawful or invidious discrimination, and with all other State efforts to guarantee fair employment practices under this Agreement, and Buyer will comply promptly with all reasonable requests and directions from the State Commission for Human Rights or any of its officers or agents relating to prevention of discriminatory employment practice. Full cooperation as expressed above shall include, but not be limited to, being a witness in any proceeding involving questions of unlawful or invidious discrimination if such is deemed necessary by any official or agency of the State of Alaska; permitting employees of Buyer to be witnesses or complainants in any proceeding involving questions of unlawful or invidious discrimination, if such is deemed necessary by any official or agency of the State of Alaska; participating in meetings; submitting periodic reports on the equal employment aspects of present and future employment; assisting in inspection of the Petrochemical Facility site during and after the construction; and promptly complying with all

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directives deemed essential by any office or agency of the State of Alaska to insure compliance with all federal and state laws, regulations and policies pertaining to the prevention of discriminatory employment practices.

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ARTICLE XXI

LOCAL HIRE AND TRAINING

25.1 Local Hire.

(1) Buyer will comply with all applicable Alaska statutes and regulations in effect at the time this Agreement becomes effective as well as all amendments thereto and subsequent enactments, providing for local or resident hire.

(2) In addition, and subject to compliance with other requirements of state or federal law or regulation, Buyer will give preference to hiring qualified and available residents over nonresidents for all work to be performed in the construction, operation and maintenance of the Petrochemical Facility. Buyer shall not discriminate against Alaska residents by differentiating between residents and nonresidents in payment of wages, salaries, fringe benefits and working conditions. Nothing shall prohibit the Buyer from hiring Alaska residents through private sources. However, if private sources are unable to supply qualified Alaska residents, Buyer shall then attempt to seek qualified Alaska residents through the Alaska Department of Labor prior to the employment of nonresidents. The Buyer shall allow said Department of Labor two days, excluding Saturday, Sunday and state holidays, to produce

See 25.1(b)(a)

qualified resident workers prior to the employment of nonresidents. If suitable resident workers are not provided within the specified time period, the Buyer may employ nonresidents possessing the qualifications necessary to perform the work. Notwithstanding the foregoing, the Buyer may hire nonresidents (i) on an emergency basis for the duration of any emergency, (ii) as casual or intermittent employees if their employment will not exceed thirty (30) working days, or (iii) as specially skilled employees when the Department of Labor agrees in advance that such specially skilled persons are unavailable within the State of Alaska.

(3) Buyer will use its best efforts to incorporate in any and all collective bargaining agreements which it enters with labor unions covering work to be performed in the construction, operation and maintenance of the Petrochemical Facility and associated facilities and operations, a provision or provisions requiring the unions' dispatch procedures be established and operated in a manner which will assure that qualified Alaska residents will be employed to perform said work.

(4) Buyer will incorporate in any and all agreements it enters with contractors and subcontractors provisions requiring the employment of qualified Alaska residents, as set forth in Article 25.1(2), and utilization of the contractors' or subcontractors' best efforts to obtain agreements with labor unions, as specified in Article 25.1(3).

(5) Noncompliance with the preceding covenants of

this Article 25.1 or of Article XXIV shall be grounds for a complaint which an aggrieved resident or the State of Alaska, on its own motion, may file with the Department of Labor against the Buyer, but shall not be considered a default under Article XIV. Buyer hereby agrees to submit to the jurisdiction of the Department of Labor for purposes of determining whether noncompliance in fact occurred. Said Department shall hold a hearing at which the parties may present relevant evidence and cross-examine witnesses prior to such a determination. Adequate notice thereof shall be given to all parties concerned. Upon a determination that noncompliance occurred, the Buyer shall pay the aggrieved party a sum equal to the amount the resident would have received had he been employed by the Buyer, up to a maximum of one (1) year's salary. If such compliance is determined to have been willful, the Department may award an additional sum up to the amount of the original sum awarded.

(6) For purposes of this Article

(a) "resident" means a person who

(i) except for brief intervals, military service, attendance at an educational or training institution, or for absences for good cause, is physically present in the state for a period of one year immediately before the time his status is determined;

(ii) maintains a place of residence in the state;

(iii) has established residency in the state;

(iv) has not, within the period of required residency, claimed residency in another state; and

(v) shows by all attending circumstances that his intent is to make Alaska his permanent residence;

provided, however, that in the event a final judgment is rendered by a court of competent jurisdiction in the State of Alaska that the one year period stated in Alaska Statutes Section 38.40.090 is unconditional because of the length of time, the one year period stated in this subparagraph shall be reduced to such period as is constitutionally acceptable;

(b) "qualified" means capable, through education, training or experience, of performing the duties and satisfying the usual terms and conditions of the employment, if those duties, terms and conditions meet the reasonable standards of the industry as required of other employees performing the same type of work in the industry;

(c) "willful noncompliance" means intentionally, knowingly, or purposely, without justifiable excuse, not giving preference to qualified Alaska residents in employment covered by this section; and

(d) "noncompliance" means not giving preference to qualified Alaska residents in employment covered by this Article 25.1.

(7) The performance of this Article 25.1 shall not be interpreted to require any action which constitutes the violation of any federal or state law or regulation, particularly those relating to discrimination in hiring.

25.2 Local Training. Buyer, in order to effectuate the purposes of Article XXIV and Article 25.1, and in order to insure the maximum practicable employment of Alaska residents in the operation and maintenance of the Petrochemical Facility, shall initiate training programs to provide skilled local personnel and adequately trained residents to apply for permanent employment in the operation and maintenance of the Petrochemical Facility. Buyer shall establish and furnish to Seller its employment requirements for the operation and maintenance of the Petrochemical Facility, including the approximate numbers of employees and identification of the types of skills needed, in sufficient time (but not more than one year) for Seller and Buyer to design and conduct its training programs in the skills required. In pursuing such programs, Buyer intends to and shall seek the support and financial aid of other groups and agencies, to wit: the federal government, Seller, municipal and local authorities, unions, and certain native Alaskan corporations. Seller will provide Buyer with reasonable assistance in the design and administration of the training program. Due to the difficulty of establishing objective criteria to insure that adequate effort has been expended by Buyer and because Buyer expects Seller to join with it in establishing such training programs and obtaining funds therefor from a variety of governmental sources, including Seller itself, Buyer's obligations under this program shall be deemed fulfilled in the event that Buyer has expended $500,000 on such training programs or, in the alternative, that an aggregate of $1,000,000 has

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been expended from all sources (including all federal, private and state funds) on such training programs on or prior to ten (10) years from the Effective Date.

25.3 Infrastructure Development. Buyer agrees to use its best efforts to coordinate construction of the Petrochemical Facility with local municipal and borough authorities in order that development of supporting residential, service and other aspects of infrastructure may be coordinated. To that end, Buyer shall seek to arrive at mutually satisfactory solutions with municipal and borough governments to the perceived heavy demand on the physical plant and services of neighboring communities as a result of the construction and operation of the Petrochemical Facility.

ARTICLE XXVI

MISCELLANEOUS

26.1 Exhibits. Exhibits "A" through "D", which are attached to this Agreement, are by this reference incorporated into and made a part of this Agreement.

26.2 Headings. The headings of this Agreement are inserted for convenience and identification only and are not intended to describe, interpret, define or limit the scope, extent or intent of this Agreement or any provision hereof.

26.3 Gender. Whenever the context requires, the gender of all words used in this Agreement shall include the masculine, feminine and neuter, and the number of all words shall include the singular and the plural.

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26.4 Counterparts. This Agreement may be executed in any number of counterparts with the same effect as if Seller and Buyer had signed one document. All counterparts shall be construed together and shall constitute one and the same instrument.

26.5 Additional Documents. In connection with this Agreement, as well as all transactions contemplated by this Agreement, Seller and Buyer agree to execute and deliver such additional documents and instruments and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all the terms, provisions and conditions of this Agreement and all such transactions.

26.6 Supplier-Purchaser Relationship. Buyer and Seller each agree to take all action reasonably necessary or appropriate to effect the transactions contemplated by this Agreement and each party's performance of its obligations hereunder. In the event that this Agreement is canceled or terminated by any party pursuant to the terms hereof, Seller and Buyer hereby agree to waive any rights which either party may have to a continuation of any supplier-purchaser relationship that may have been established with respect to the State of Alaska royalty crude oil for purposes of any federal mandatory crude oil allocation program. Specifically, the Buyer expressly states and the Seller agrees that the consent given in the immediately preceding sentence is such a consent to the termination of any supplier-purchaser relationship between the Seller and the Buyer which may be deemed to exist

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under the Federal Mandatory Petroleum Allocation Regulations (10 C.F.R., Part 211) as is provided in 10 C.F.R. 211.63(d)(1)(i) of such Regulations. Seller and Buyer also agree that any subsequent contracts for the sale, exchange or other disposition of the State of Alaska royalty crude oil that may be entered into by the Buyer or Seller herein will include the advance written consent of the purchaser, exchange partner or other recipient of the crude oil to the termination of any supplier-purchaser relationship which may be deemed to exist with respect to the State of Alaska royalty crude oil for purposes of any mandatory crude oil allocation program upon the expiration, cancellation or termination of the underlying contractual agreement for the sale, exchange or other disposition of the crude oil or in the event that the agreement between the Seller and the Buyer for the sale and purchase of the crude oil is terminated for any reason, including termination for default as stated in Articles IX and XIV or because Buyer fails to meet its obligations under Article 10.2. Buyer also agrees to include in any contracts for the sale, exchange or other disposition of the State of Alaska royalty crude oil an agreement by the purchaser, exchange partner or other recipient of the crude oil to include identical waiver provisions in all subsequent sales, exchanges or other disposition of the crude oil by that purchaser, exchange partner or other recipient and by any subsequent purchasers, exchange partners or other recipients.

26.7 Reasonableness of Approvals. Buyer and Seller agree

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that as to any approvals or consents required of either of them under this Agreement, except for extensions of time periods under Article 10.2, such approvals or consents shall not be unreasonably withheld.

IN WITNESS WHEREOF, the Seller has caused this Agreement to be executed by its Commissioner of Natural Resources and the Buyer has caused this Agreement to be executed by its President, thereunto duly authorized by its Board of Directors in accordance with the certified seal, duly attested, to be affixed hereto, as of the day and year first above written.

THE STATE OF ALASKA

ATTEST:

_____ By: _____
Commissioner, Department
of Natural Resources
"SELLER"

APPROVED AS TO FORM:

_____

ALASKA PETROCHEMICAL COMPANY

ATTEST:

_____ By: _____
President
"BUYER"

I, _____, certify that I am the Secretary of the corporation named as Buyer in the above contract, that

_____ was then President of said corporation; that said Agreement was duly signed for and in behalf of said corporation by authority of its governing body, and is within the scope of its corporate powers.

_____
Secretary

(CORPORATE SEAL)

THE STATE OF ALASKA)
) ss.
_____ JUDICIAL DISTRICT)

THIS IS TO CERTIFY that on this _____ day of _____, 1978, before me, the undersigned, a Notary Public in and for the State of Alaska, duly commissioned and sworn as such, personally appeared _____, to me known to be the Commissioner of Natural Resources for the STATE OF ALASKA, and known to me to be the person who executed the within instrument on behalf of the STATE OF ALASKA, and acknowledged to me that the same was signed as a free act and deed of the STATE OF ALASKA for the purposes and uses therein stated.

WITNESS my hand and notarial seal the day and year last above written.

_____
NOTARY PUBLIC in and for Alaska.
My commission expires:_____

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THE STATE OF ALASKA)
) ss.
_____ JUDICIAL DISTRICT)

THIS IS TO CERTIFY that on the _____ day of _____, 1978, before me, the undersigned, a Notary Public in and for the State of Alaska, duly commissioned and sworn as such, personally appeared the President of ALASKA PETROCHEMICAL COMPANY, an Alaska corporation, and known to me to be the person who executed the within instrument on behalf of the corporation herein named, and acknowledged to me that the same was signed as a free act and deed of said corporation for the uses and purposes therein stated and pursuant to its Bylaws or a resolution of its Board of Directors.

WITNESS my hand and notarial seal the day and year last above written.

_____
NOTARY PUBLIC in and for Alaska.
My commission expires:_____

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CERTIFICATE

I, _____, President and a member of the Board of Directors of ALASKA PETROCHEMICAL COMPANY, an Alaska corporation, do hereby certify that the following is a true and correct copy of a resolution adopted by the Board of Directors of said ALASKA PETROCHEMICAL COMPANY at a special meeting duly called and held at _____, Alaska, on _____, 1978:

> BE IT RESOLVED by the Board of Directors of Alaska Petrochemical Company that the Agreement for the Sale and Purchase of State Royalty Oil between Alaska Petrochemical Company and the Commissioner of Natural Resources of the State of Alaska presented to the Board at a special meeting duly called and held in _____, Alaska, on _____, 1978, be and is hereby approved;
>
> BE IT FURTHER RESOLVED that the officers of the corporation be and hereby are authorized and directed to execute said Agreement for the Sale and Purchase of State Royalty Oil in the name of Alaska Petrochemical Company, and all further agreements and instruments that may be necessary or desirable to implement the purposes of that agreement.

_____
President

SUBSCRIBED and SWORN to before me this _____ day of _____, 1978.

_____
NOTARY PUBLIC in and for Alaska.
My commission expires: _____

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EXHIBIT "A"

Attached to and Made a Part of the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, 1978, between ALASKA PETROCHEMICAL COMPANY, an Alaska corporation "Buyer", and the COMMISSIONER OF NATURAL RESOURCES OF THE STATE OF ALASKA, acting pursuant to Alaska Statute 38.05.183, "Seller", With Respect to Certain Royalty Oil Owned and Taken In-Kind by Seller Under the Leases Described Herein Covering Lands in the State of Alaska.

Tract No.	Description	No. of Acres	ADL Serial No.	Basic Royalty	Lessee of Record	O.R.R. Interest	Working Interest Ownership
	(Umiat Meridian, Alaska)						
1	T12N-R11E, Secs. 9, 10	1,280	47445	1/8	Mobil and Chevron		Mobil—50% Chevron—50%
2	T12N-R11E, Secs. 11, 12	1,280	28235	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
3	T12N-R12E, Sec. 7	580	28254	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
4	T12N-R15E, Sec. 23, 24	1,280	34625	1/8	Sohio Petroleum Co.	*	Sohio—100%
5	T12N-R15E, Secs. 21, 22	1,280	34626	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
6	T12N-R15E, Secs. 19, 20	1,225	34627	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
7	T12N-R14E, Secs. 23, 24	1,280	34624	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
8	T12N-R14E, Sec. 22	640	28297	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
9	T12N-R13E, Sec. 19	585	47469	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
10	T12N-R12E, Secs. 23, 24	1,280	47448	1/8	Mobil and Phillips		Mobil—66⅔% Phillips—33⅓%
11	T12N-R12E, Secs. 21, 22	1,280	28256	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
12	T12N-R12E, Secs. 17, 18, 19, 20	2,448	28255	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
13	T12N-R11E, Secs. 13, 14, 23, 24	2,560	28237	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
14	T12N-R11E, Secs. 15, 16, 21, 22	2,560	47447	1/8	Mobil and Chevron		Mobil—50% Chevron—50%
15	T12N-R11E, Secs. 17, 18, 19, 20	2,448	47446	1/8	Mobil and Chevron		Mobil—50% Chevron—50%
16	T12N-R10E, Secs. 13, 24	1,280	25637	1/8	A.R.Co., BP Alaska, Sohio Petroleum Co.		A.R.Co.—50% BP Alaska—37½% Sohio—12½%
17	T12N-R11E, Secs. 29, 30, 32	1,868	47449	1/8	Mobil and Chevron		Mobil—50% Chevron—50%
18	T12N-R11E, Secs. 27, 28, 33, 34	2,560	28239	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
19	T12N-R11E, Secs. 25, 26, 35, 36	2,560	28238	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
20	T12N-R12E, Secs. 29, 30, 31, 32	2,459	28259	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
21	T12N-R12E, Secs. 27, 28, 33, 34	2,560	28258	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
22	T12N-R12E, Secs. 25, 35, 36, N/2 and SE/4 Sec. 26	2,400	28257	1/8	Mobil and Phillips		Mobil—50% Phillips—50%

*See comment on page A-5.

Tract No.	Description	No. of Acres	ADL Serial No.	Basic Royalty	Lessee of Record	O.R.R. Interest	Working Interest Ownership
	(Umiat Meridian, Alaska)						
52	T11N-R11E, Sec. 15	640	28244	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
53	T11N-R11E, Secs. 13, 14, 24	1,920	28245	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
54	T11N-R12E, Secs. 17, 18, 19	1,840	28262	1/8	Chevron		Chevron—100%
54A	T11N-R12E, Sec. 20	640	28262	1/8	Chevron, Mobil, Phillips		Chevron—33⅓% Mobil—33⅓% Phillips—33⅓%
55	T11N-R12E, Secs. 15, 16	1,280	28263	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
55A	T11N-R12E, Secs. 21, 22	1,280	28263	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
56	T11N-R12E, Secs. 13, 14, 23, 24	2,560	47451	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
57	T11N-R13E, Secs. 17, 18, 19, 20	2,480	28283	1/8	Sohio Petroleum Co.	*	Sohio—100%
58	T11N-R13E, Secs. 15, 16, 21, 22	2,560	28284	1/8	Sohio Petroleum Co.	*	Sohio—100%
59	T11N-R13E, Secs. 13, 14, 23, 24	2,560	28285	1/8	Sohio Petroleum Co.	*	Sohio—100%
60	T11N-R14E, Secs. 17, 18, 19, 20	2,480	28305	1/8	Sohio Petroleum Co.	*	Sohio—100%
61	T11N-R14E, Secs. 15, 16, 21, 22	2,560	28306	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
62	T11N-R14E, Secs. 13, 14, 23, 24	2,560	28307	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
63	T11N-R15E, Secs. 17, 18, 19, 20	2,480	28321	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
64	T11N-R15E, Secs. 15, 16, 21, 22	2,560	28322	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
65	T11N-R15E, Secs. 13, 14, 23, 24	2,560	28323	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
66	T11N-R16E, Secs. 17, 18, 19	1,840	28339	1/8	Sohio Petroleum Co.	*	Sohio—100%
67	T11N-R16E, Secs. 15, 16	1,280	28340	1/8	Sohio Petroleum Co.	*	Sohio—100%
68	T11N-R16E, Secs. 13, 14	1,280	28341	1/8	Sohio Petroleum Co.	*	Sohio—100%
69	T11N-R16E, Secs. 30, 31, 32	1,851	28343	1/8	Sohio Petroleum Co.	*	Sohio—100%
70	T11N-R15E, Secs. 25, 26, 35, 36	2,560	28324	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
71	T11N-R15E, Secs. 27, 28, 33, 34	2,560	28325	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
72	T11N-R15E, Secs. 29, 30, 31, 32	2,491	28326	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
73	T11N-R14E, Secs. 25, 26, 35, 36	2,560	28308	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
74	T11N-R14E, Secs. 27, 28, 33, 34	2,560	28309	1/8	Sohio Petroleum Co.	*	Sohio—100%
75	T11N-R14E, Secs. 29, 30, 31, 32	2,491	28310	1/8	Sohio Petroleum Co.	*	Sohio—100%
76	T11N-R13E, Secs. 25, 26, 35, 36	2,560	28286	1/8	Sohio Petroleum Co.	*	Sohio—100%
77	T11N-R13E, Secs. 27, 28, 33, 34	2,560	28287	1/8	Sohio Petroleum Co.	*	Sohio—100%
78	T11N-R13E, Secs. 29, 30, 31, 32	2,491	28288	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
79	T11N-R12E, Secs. 25, 26, 35, 36	2,560	28264	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%

*See comment on page A-5.

Tract No.	Description	No. of Acres	ADL Serial No.	Basic Royalty	Lessee of Record	O.R.R. Interest	Working Interest Ownership
	(Umiat Meridian, Alaska)						
80	T11N-R12E, Secs. 27, 28, 33, 34	2,560	47452	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
81	T11N-R12E, Secs. 29, 30, 31, 32	2,491	47453	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
82	T11N-R11E, Sec. 25	640	28246	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
83	T10N-R12E, Secs. 3, 4, 10	1,920	47454	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
84	T10N-R12E, Secs. 1, 2, 11, 12	2,560	28265	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
85	T10N-R13E, Secs. 6, 7, 8, S/2 and NE/4 Sec. 5	2,341	28289	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
85A	T10N-R13E, NW/4 Sec. 5	160	28289	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
86	T10N-R13E, Secs. 3, 4, 9, 10	2,560	47471	1/8	Amerada Hess, et. al.		Amerada Hess—27% Getty—30.5% LL&E—13.25% Placid—9.125% N. B. Hunt—6.3625% Hunt Ind.—3.8625% Caroline Hunt Tr.—3.3% Wm. Herbert Hunt Tr.—3.3% Lamar Hunt Tr. Est.—3.3%
87	T10N-R13E, Secs. 1, 2, 11, 12	2,560	47472	1/8	Amerada Hess and Getty		Amerada Hess—50% Getty—50%
88	T10N-R14E, Secs. 5, 6, 7, 8	2,501	28313	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
89	T10N-R14E, Secs. 3, 4, 9, 10	2,560	28312	1/8	Sohio Petroleum Co.	*	Sohio—100%
90	T10N-R14E, Secs. 1, 2, 11, 12	2,560	28311	1/8	Sohio Petroleum Co.	*	Sohio—100%
91	T10N-R15E, Secs. 5, 6, 7, 8	2,501	28329	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
92	T10N-R15E, Secs. 3, 4, 9, 10	2,560	28328	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
93	T10N-R15E, Secs. 1, 2, 11, 12	2,560	28327	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
94	T10N-R16E, Secs. 5, 6, 7, 8	2,501	28345	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
95	T10N-R16E, Secs. 4, 9	1,280	28344	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
96	T10N-R16E, Sec. 16	640	28347	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%

*See comment on page A-5.

Tract No.	Description	No. of Acres	ADL Serial No.	Basic Royalty	Lessee of Record	O.R.R. Interest	Working Interest Ownership
	(Umiat Meridian, Alaska)						
97	T10N-R16E, Secs. 17, 18, 19, 20	2,512	28346	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
98	T10N-R15E, Secs. 13, 14, 23, 24	2,560	28332	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
99	T10N-R15E, Secs. 15, 16, 21, 22	2,560	28331	1/8	Sohio Petroleum Co.	*	Sohio—100%
100	T10N-R15E, Secs. 17, 18, 19, 20	2,512	28330	1/8	Sohio Petroleum Co.	*	Sohio—100%
101	T10N-R14E, Secs. 13, 14, 23, 24	2,560	28315	1/8	Sohio Petroleum Co.	*	Sohio—100%
102	T10N-R14E, Secs. 15, 16, 21, 22	2,560	28314	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
103	T10N-R14E, Secs. 17, 18, 19, 20	2,512	47475	1/8	Amerada Hess, et. al.		Amerada Hess—25% Getty—25% Marathon—25% Placid—7.5% N. B. Hunt—5% Hunt Ind.—3.125% Caroline Hunt Tr.—3.125% Wm. Herbert Hunt Tr.—3.125% Lamar Hunt Tr. Est.—3.125%
104	T10N-R13E, Secs. 13, 14, 24	1,920	47476	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
105	T10N-R13E, Secs. 15, 16	1,280	28290	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
106	T10N-R14E, Secs. 27, 28	1,280	47482**	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
107	T10N-R14E, Secs. 26, 36	1,280	28316	1/8	Chevron		Chevron—100%
107A	T10N-R14E, Sec. 25	640	28316	1/8	Chevron, Mobil, Phillips		Chevron—33⅓% Mobil—33⅓% Phillips—33⅓%
108	T10N-R15E, Secs. 29, 30, 31, 32	2,523	28335	1/8	Sohio Petroleum Co.	*	Sohio—100%
109	T10N-R15E, Secs. 33, 34	1,280	28334	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
109A	T10N-R15E, Secs. 27, 28	1,280	28334	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
110	T10N-R15E, Secs. 25, 26, 35, 36	2,560	28333	1/8	Sohio Petroleum Co.	*	Sohio—100%
111	T10N-R16E, Secs. 29, 30, 31	1,583	28349	1/8	Sohio Petroleum Co.	*	Sohio—100%
		245,767					

*BP Alaska, Inc. owns an overriding royalty interest equal to 75% of all net profits from production between certain levels of oil production.

**This Tract Number 106 was assigned to A.R.Co. and Exxon. Upon approval of the assignment by the Director a new ADL Serial No. will be given to this Tract.

EXHIBIT "B"

Calculation of monthly in value royalty under the Leases and leases (all calculations shall be rounded to the nearest $0.001)

STEP 1: Calculate each producer's weighted average value per barrel at Point of Delivery for all oil sold by each producer during the month, as follows:

Example, Producer Y

(1) Destination	(2) Volume Sold	(3) Sales Price at Destination	(4) Shipping Costs	(5) Pipeline Tariff	(6) Point of Delivery Value	(7) Weighted Average Value
1	2,000,000	$12.500	$ -0-	$4.770	$7.730	-
2	4,000,000	13.370	1.110	4.750	7.510	-
3	5,000,000	13.440	3.830	4.750	4.860	-
						$6.345

Columns 2, 3, 4 and 5 shall be computed from actual data as reported by each producer and filed with the State of Alaska for royalty purposes and severance tax purposes.

STEP 2: The "weighted average value" per barrel of each producer (column 7 above) at the Point of Delivery shall then be used in column (9) below in calculating the applicable in value price for each producer (column 11 below), the weighted average of which shall be the In Value Price to Buyer (column 12), as follows:

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-continued-

Example, all producers:

(8) Producer and Quantity	(9) Wtd. Avg. Value at Point of Delivery (Col. 7)	(10) Wtd. Avg. Price Received by all other Producers	(11) Applicable Price for In Value Calculation	(12) In Value Price to Buyer
X; 4,200,000	$6.920	$6.404	$6.920	-
Y; 11,000,000	6.345	7.003	7.003 ✓	-
Z; 500,000	7.700	6.504	7.700	-
Weighted Avg.	$6.542			$7.003 ✓

Notes:

1) Values in column 10 are the weighted average of all producers other than the producer for which the calculation is being made.

2) Column 11 is the highest of the values in columns 9 or 10 for each producer.

3) Column 12 is the weighted average of values in column 11.

4) Buyer shall not pay any reimbursable costs under Article 8.2 until such costs are judicially determined as owing.

5) There is no posted price. "Market" or "field" value shall not be used in calculating the "In Value price to Buyer" unless and until the methodology of determining same is judicially decided.

6) Subject to later adjustment under Article 9.5.

AGO 545784

EXHIBIT "C"

FORM OF BOND

The bond shall be in a form submitted by Buyer and shall contain such terms and conditions as are approved by the Commissioner.

AGO 545785

EXHIBIT "D"

SUPPLEMENTAL ENVIRONMENTAL STANDARDS

VESSEL SAFETY AND MANEUVERABILITY FEATURES

1. Buyer agrees that all tank vessels of 1,600 gross tons or more which it owns and operates directly or through an Affiliate in marine transportation of petroleum, while navigating the coastal waters of the state, shall be equipped with the following:

(a) LORAN-C navigational equipment, or better;

(b) two marine radar systems, meeting either U. S. Marine Administration Standards for Merchant Ship Construction (COM-72-11469, Dec. 1972), or Radio Technical Commission for Marine Services performance specifications for a general purpose navigational set for ocean going ships of 1,600 tons gross tonnage and upwards (RTCM-Paper 106-75/EC-167/SC65-191 BRWG-45, or, RTCM-Paper 104-74/ED-140 BRWG 42), one of which must always be in operation, or better;

(c) those tank vessels of 20,000 DWT and over shall have at least one of the radars fitted with a collision avoidance system meeting either U. S. Maritime Administration Standards for Merchant Ship Construction (COM-72-11469, Dec. 1972), or the Radio Technical Commission for Marine Services performance specifications for a computer aided collision avoidance system for merchant ships (RTCM-Paper 171-76/EC-205/SC65-226), or better.

AGO 545786

2. Except for vessels equipped with lateral thrust equipment and astern horsepower equal to forty percent (40%) of rated horsepower, tank vessels of 20,000 DWT or more owned and operated by Buyer directly or through an Affiliate shall be escorted by tugs having an aggregate shaft horsepower equivalent to five percent of the deadweight tonnage of the escorted vessel when navigating between the Alyeska Terminal at Port Valdez and Bligh Reef, when docking at the Alyeska Terminal, and, after the Petrochemical Facility is operational, at the port facility serving the Petrochemical Facility.

BALLAST WATER TREATMENT

3. With respect to tank vessels owned and operated by Buyer directly or through an Affiliate which carry petroleum, Buyer agrees that no ballast which has been placed in cargo tanks or tank cleaning waste-water will be discharged into the waters of the state. All oily water (including, but not limited to, discharges from fuel tanks, cargo tanks, ballast tanks, slop tanks and bilges, which contain oil, grease, refined petroleum products or their by-products, including petrochemicals) discharged from any tank vessel owned and operated by Buyer directly or through an Affiliate in the State of Alaska shall be received and treated by a waste-water treatment facility meeting the effluent limitations specified in the next paragraph.

4. Buyer will maintain and operate a waste-water treatment facility for the reception and treatment of ballast carried in cargo tanks and tank cleaning waste-water at or near the place where the petroleum will be transferred from the Petrochemical Facility to vessels for marine transport. Water discharged from said treatment facility shall not contain more than 10 parts of oil, grease, refined petroleum products or their by-products, including petrochemicals, per million parts of water, on a weekly (7 day) average. Buyer will consult with the Department of Fish and Game and Environmental Conservation in connection with designing and constructing said waste-water treatment facility in order that the effect of the effluent discharged from the facility on the receiving environment and the fisheries in that environment will be minimized.

PROOF OF FINANCIAL RESPONSIBILITY

5. Buyer will obtain and maintain or cause to be obtained and maintained insurance in the face amount of $20,000,000 or a corporate indemnity or guarantee of performance in an equivalent amount by a corporation or entity acceptable to the Commissioner, for each and every tank vessel owned and operated by it directly or through an Affiliate that calls at Alaskan ports and carries petroleum to compensate third parties for damages resulting from the unlawful discharge of petroleum within or affecting land or

water within the territorial jurisdiction of the State of Alaska. Buyer will also obtain and maintain insurance for each and every oil terminal facility it owns, operates or controls in Alaska, in the face amount of $100,000 for each facility with a tank capacity of less than 200,000 barrels of petroleum, and in the face amount of $1,000,000 for each facility with a tank capacity of 200,000 barrels or more of petroleum, to compensate third parties for damages resulting from the unlawful discharge of petroleum within or affecting land or water within the jurisdiction of the State of Alaska while said petroleum is being transferred. In the event any other insurance is required by applicable federal or state law to cover the same risks described in this paragraph, the face amount of any such other insurance shall be considered as a part and in reduction of the face amount of insurance required by this paragraph. The insurance shall be issued by an insurer which is either authorized to sell in the State of Alaska by the Department of Commerce and Economic Development, Division of Insurance, or is an authorized insurer listed by the Division as not disapproved for use in the State of Alaska. The deductible provision in any policy of insurance, binder or certificate shall be unacceptable if it exceeds five percent (5%) of the face amount unless the Buyer demonstrates acceptable supplemental coverage or credit worthiness. The terms of the insurance shall provide that termination or cancellation of the insurance, including expiration by its terms, insofar as it relates to the insured's liability arising from a discharge of

oil within or affecting the land and water within the territorial jurisdiction of the State of Alaska, will not be effective until thirty days after notice in writing has been posted (prepaid and certified) by the insurer to the insured and to the Alaska Department of Environmental Conservation at its office in Juneau, Alaska. Buyer will annually provide the Department of Environmental Conservation (or its successor in responsibility) evidence of said insurance for the respective vessels and facilities and its coverage of said damages during the month of January.

PETROLEUM SPILL CLEANUP AND CONTINGENCY PLANS

6. Buyer shall be responsible for the detection, location, confinement and cleanup of petroleum discharges at the Petrochemical Facility. At least 180 days prior to scheduled start-up of the Petrochemical Facility, Buyer shall submit its contingency plans to the Department of Environmental Conservation for review as being in compliance with applicable law and regulation. The plans shall provide for immediate corrective action in the event of petroleum discharges, including confinement and cleanup. The plans shall include separate and specific techniques and schedules for cleanup of petroleum discharges on land and sea and in lakes, rivers, streams and estuaries, to the extent such water resources are in proximity to the Petrochemical Facility.

DEFINITIONS

7. In this exhibit,

(a) "discharge" means any spilling, leaking, pumping, pouring, emitting, emptying or dumping;

(b) "DWT" or "deadweight tons" means the difference in metric tons between the lightweight displacement and the total displacement of a vessel measured in water of specific gravity 1.025 at the load waterline corresponding to the assigned summer freeboard;

(c) "oil terminal facility" means an onshore or offshore facility of any kind and related appurtenances, including but not limited to a deepwater port, located in, on, or under the surface of any land or water of the state, including title and submerged land, which is used or capable of being used for the purpose of transferring, processing or refining, or storing petroleum as it is defined in this section;

(d) "petroleum" means all crude oil purchased under this Agreement, and all refined petroleum products and petroleum by-products, including petrochemicals, produced at the Petrochemical Facility from such petroleum;

(e) "tank vessel" means a self-propelled vessel that is specially constructed or converted to carry bulk cargo in tanks and includes tankers, tankships and combination carriers;

(f) "transferred" includes both onloading and offloading between terminal and vessel; and

(g) "waters of the state" means the navigable waters within the territorial limits of the State of Alaska, and the marginal sea adjacent to the State of Alaska, as defined in AS 44.03 and AS 46.03.900(22) or any successor provisions.

PETROCHEMICALS IN ALASKA

THE ALPETCO STORY



ALASKA PETROCHEMICAL COMPANY

March 15, 1978

AGO 545793

FOREWORD

In August 1977 Alaska Petrochemical Company (Alpetco) was one of several companies to submit proposals to the State of Alaska Royalty Oil and Gas Development Advisory Board to purchase the State's Prudhoe Bay royalty crude oil and to use it as feedstock for a refinery in Alaska. Alpetco's proposal involves more permanent jobs and a larger tax base than any of the other proposals. On February 19, 1978 the Governor of Alaska recommended that Alpetco be selected from among four finalists in the competition. On February 22 the Alaska State Royalty Oil and Gas Development Board unanimously approved and Alpetco executed a 27 year contract with the State of Alaska for the purchase of up to 150,000 barrels per day of royalty crude oil. Prior to becoming effective, the contract must be ratified by both houses of the Alaska legislature.

March 15, 1978

Alaska Petrochemical Company

601 West 5th Avenue
Anchorage, Alaska 99501
(907) 272-1517

2200 Post Oak Tower
5051 Westheimer Road
Houston, Texas 77056
(713) 621-8710

AGO 545794

THE ALPETCO CONCEPT

The Alpetco Concept was developed as the foundation of Alaska Petrochemical Company's proposal to the State of Alaska. Alpetco's concept for what is in the best interest of all Alaskans has remained unchanged:

THE ALPETCO CONCEPT

"The State of Alaska has determined to take its one-eighth royalty on the North Slope crude oil 'in kind' rather than 'in dollars.'

There is little justification for the State of Alaska to take its royalty oil 'in kind' unless value is added to the crude product before it leaves Alaska. If the State's crude is to be sold to someone 'as is,' the State may as well take the crude 'in value,' letting the producing oil companies handle shipping and marketing and the State collect its royalty 'in dollars.' On the other hand, if value is added in Alaska then substantial benefits can be created for the State of Alaska and its citizens. The more value added in Alaska, the better.

Assuming the crude oil to be worth $13 a barrel at Valdez, it will be processed further — somewhere — until it has an added value of $30, $50, $100, $150 or $200 per barrel. Adding such values requires plants and payrolls. These can be in Alaska or on the California or Gulf Coasts. Why not in Alaska?

A plant investment of $1 billion or more is necessary to add such values. The property and revenue taxes on this real property will go to the State in which the plant is located. Why not to Alaska?

The jobs and payrolls created by adding these values are permanent jobs and payrolls, not temporary. Why not for Alaskans?

Additional industry will spring up around the petrochemical complex — wherever it is located — to add further value to its wide range of products, thus creating additional permanent jobs and payrolls. Why not in Alaska?

ALPETCO's proposed program will add maximum value to the product, and this value will be added **in Alaska** and **by Alaskans.**"

August 1, 1977

CHRONOLOGY OF ALPETCO EVENTS

August 1, 1977	Preliminary proposals submitted to the State
October 15, 1977	Detailed proposals submitted
February 17, 1978	Final contract offer submitted
February 19, 1978	Governor Hammond chose Alpetco
February 22, 1978	Royalty Oil and Gas Development Advisory Board voted to accept Alpetco's contract
February 22, 1978	Alpetco contract executed

AGO 545796

WHO IS ALPETCO?

Alpetco is a new company, incorporated in Alaska. It is owned by three shareholders, each of whom is a corporation. Alaska Interstate Company owns 60% of Alpetco; Alaska Consolidated Shipping, Inc. owns 20%; and Barbour Oil Company owns 20%.

Alaska Interstate is a publicly owned Alaska corporation engaged in energy and manufacturing businesses. The company is the only Alaska company listed on the New York Stock Exchange. In 1977, revenues were nearly $190 million. Alaska Interstate businesses include transmission and distribution of natural gas in Alaska (Alaska Pipeline Company and Anchorage Natural Gas, both headquartered in Anchorage); exploration, production and liquefaction of natural gas in Indonesia; exploration and production of oil and natural gas in the U.S.; engineering and construction of gas processing facilities; pollution control and sulfur recovery processes; and manufacturing.

Alaska Consolidated Shipping is owned 51% by six Alaska Native Regional Corporations whose shares are owned by 34,000 Alaskans. The Native corporations owning control of ACS are:

The Aleut Corporation

Bristol Bay Corporation

Calista Corporation

Chugach Natives, Inc.

Cook Inlet Regional Corporation

Koniag Regional Native Corporation

Seatrain Lines, Inc., a major U.S. shipping and shipbuilding company owns 49% of ACS. The stock of Seatrain is publicly owned and listed on the New York Stock Exchange. Seatrain's revenues last year exceeded $400 million. The company is engaged in tanker and containerized cargo transportation throughout the world. Seatrain operates a major shipyard located at the former Brooklyn Navy Yard in New York and has completed four petroleum tankers of 225,000 deadweight tons each. The company also owns a 36,000 barrel per day petroleum refinery in Texas.

Barbour Oil Company, a family owned company in Houston, owns 20% of Alpetco. The late John D. Barbour, Sr., was founder of Alpetco and was the principal of Barbour Oil.

AGO 545797

WHO IS THE MANAGEMENT OF ALPETCO?

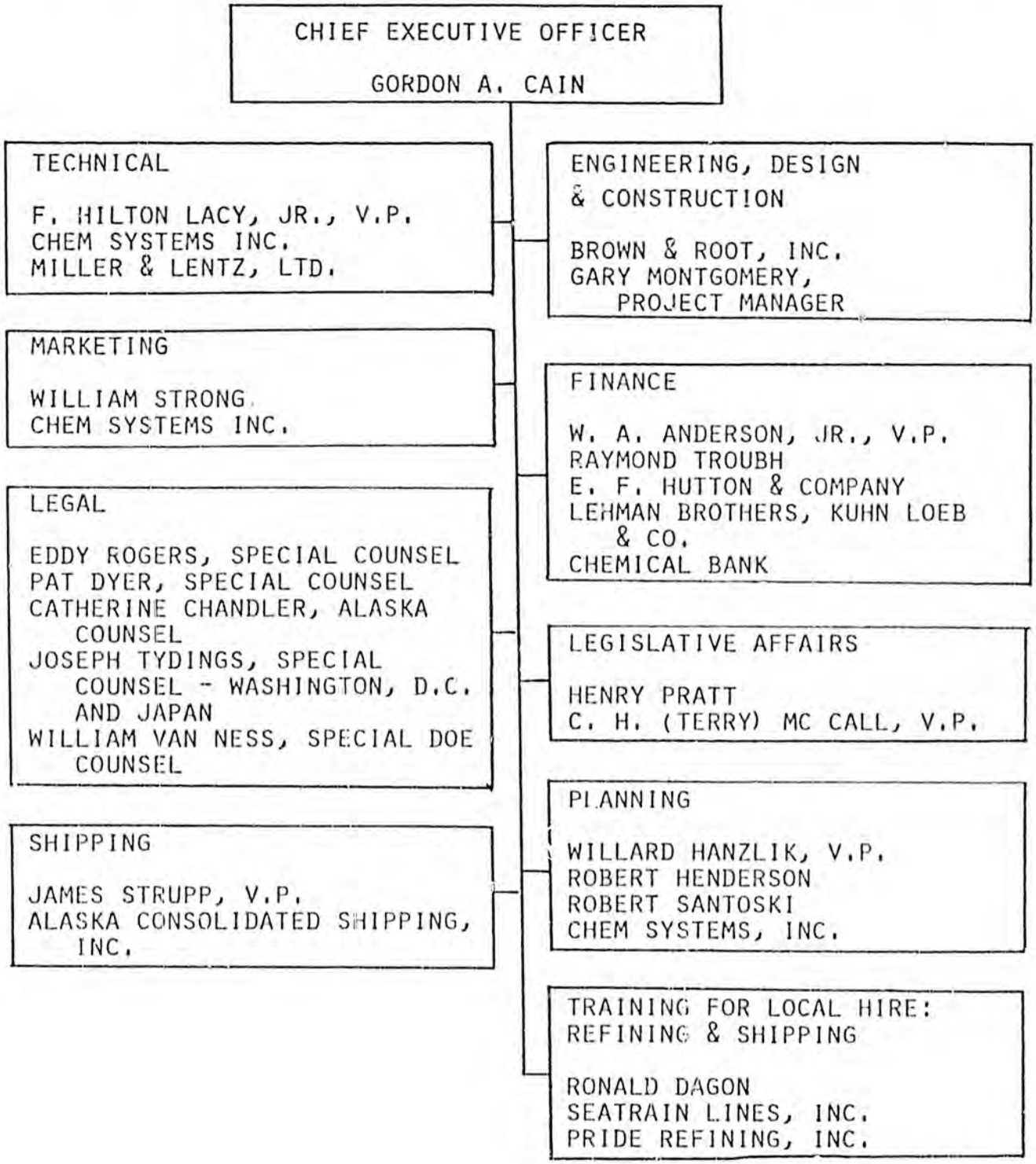
Alpetco is governed by a board of directors and managed by officers elected by the board.

Members of the Board of Directors	Principal Occupation and Residence
O. Charles Honig	Chairman and Chief Executive Officer, Alaska Interstate Company (Houston)
Gordon A. Cain	Chief Executive Officer, Alpetco (Houston)
W. A. Anderson, Jr.	Vice President — Finance, Alaska Interstate Company (Houston)
John Gundersen	Representative, The Aleut Corporation (Seattle)
Willard M. Hanzlik	Vice President, Alaska Interstate Company (Houston)
F. Hilton Lacy, Jr.	Vice President — Special Projects, Alaska Interstate Company (Houston)
Sam C. Oliphant	Retired, formerly Senior Vice President Tenneco, Inc. (Granite Shoals, Texas)
C. F. McCall	Senior Vice President, Alaska Interstate Company (Houston)
James J. Strupp	Vice President, Seatrain Lines, Inc. (New York)

AGO 545798

The following chart indicates the organization and management of Alpetco during the development phase of the project:

ORGANIZATION AND MANAGEMENT – DEVELOPMENT PHASE



AGO 545799

WHO ARE THE EXPERTS ADVISING ALPETCO?

The company has retained experts in four categories: marketing and technical, financial, project management and legal affairs.

Marketing and technical consultants: Alpetco has retained Chem Systems Inc., a leading international firm specializing in the petrochemical industry to work closely in all aspects of planning and implementation of the project. Chem Systems is well known in the industry and includes as its clients most of the world's leading oil and chemical companies. They are experienced in petrochemical project development worldwide, including: U.S., Western Europe, Japan, and the Middle East.

Financial advisors: Two major investment banking firms and a large New York commercial bank have advised Alpetco since its inception. Alpetco's co-investment bankers are E. F. Hutton & Co. and Lehman Brothers, Kuhn Loeb & Co., two of the oldest and most experienced firms on Wall Street. Chemical Bank (New York), the nation's sixth largest bank, is Alpetco's lead commercial bank.

Project Managers: Brown & Root, Inc., the largest contractor in the United States, is Alpetco's project manager. Brown & Root is experienced in all phases of developing a petrochemical project including conceptual planning, design, optimization, engineering and construction. Brown & Root has been closely involved with the Alpetco project since August, 1977.

Japanese and Washington affairs: The Washington, D.C. law firm of Danzansky, Dickey, Tydings, Quint & Gordon is advising Alpetco on matters in Washington and in Japan. The firm represents several Japanese government and industry groups in Washington and is knowledgable in government and industry relations in both capitals.

Department of Energy matters: The Washington, D.C. law firm of Van Ness, Feldman & Sutcliffe is advising Alpetco on matters relating to the U.S. Department of Energy. The firm has obtained a very important favorable opinion from the Department of Energy for Alpetco which will protect the state of Alaska's interests under present federal energy regulations.

WHAT DOES ALPETCO PROPOSE TO DO?

The company will build and operate a 150,000 barrel per day refinery and petrochemical facility in Alaska. The project is expected to require approximately six years to engineer and build; after completion Alpetco will use royalty oil for feedstock during the 27 year term of the contract.

AGO 545800

The proposed facility has not been finally configured because optimum design will be based on a number of factors, such as product requirements of purchasers, location of the facility and availability of other feedstocks. However, in general, Alpetco expects that the facility will make a broad range of petrochemicals including aromatics (benzene, toluene and xylene) and olefins (ethylene, propylene, butadiene). Ultimately Alpetco expects that both high and low density polyethylene, polypropylene and other petrochemicals (e.g. aromatics derivatives) may be manufactured in Alaska at downstream components of the facility.

Alpetco will also make certain fuel products for use in Alaska.

Most of the products from the Alpetco facility will be surplus to the needs of industry in Alaska; therefore, Alpetco is seeking markets outside, primarily the U.S. West Coast and the Pacific Basin including Japan.

WHAT IS THE SCHEDULE FOR THE ALPETCO PROJECT?

After the Alaska legislature approves the contract, Alpetco will have six months to select a site for the facility. During this time engineers and site selection experts from Alaska will thoroughly analyze possible locations from Southeast to Cook Inlet. During the following 90 days, the State will conduct public meetings to discuss Alpetco's site preference prior to approving the site.

Detailed planning will begin immediately upon ratification of the contract. While construction in some site work, including utilities and storage facilities, can be started earlier, construction of the refinery and petrochemical units probably won't begin for at least 30 months after contract ratification. Construction of the facilities will require approximately 3½ years.

DO PETROCHEMICALS MAKE ECONOMIC SENSE FOR ALASKA?

Very simply, yes. Until recently, most petrochemicals have been made on the Gulf Coast with gas feedstocks. Now those feedstocks are becoming more expensive, compared to crude oil, and refining and processing facilities are being built nearer to the source of the feedstocks.

A very large and rapidly growing market for petrochemicals exists today on the West Coast. There is no indication that large world-scale plants are being planned for this market. To supply the West Coast with petrochemical products in the future, more foreign (Middle East) crude oil will need to be shipped to the Gulf Coast for processing into petrochemicals, and then transported again by ship or rail to the West Coast.

This amount of long distance shipping and multiple handling is very costly. An Alaskan facility will have the advantage of being able to ship petrochemicals directly down the coast to markets in British Columbia, Washington, Oregon and California.

While construction and operating costs will be higher in Alaska than they are on the Gulf Coast, they are expected to be lower than in the Middle East.

Finally, the key to the economics of Alpetco's project is the value placed on a long-term supply of crude oil from a politically secure source, such as Alaska. In the future, particularly in the mid-1980's and beyond, Alpetco believes that Alaska oil will be extremely valuable as a feedstock for petrochemicals.

IS THERE A NEED FOR PETROCHEMICALS FROM ALASKA?

Today, in early 1978, there is a general oversupply of most petrochemicals in world markets. However the outlook for future needs indicates a strong growth in demand, and a need for additional petrochemical capacity in the U.S., particularly to serve West Coast and other Pacific Basin markets.

Future growth rates of basic petrochemicals are expected to remain quite high (5% to 6% annually through 1990) compared to much lower rates of growth for petroleum (fuels) products (.6% by 1990). Chart A shows the expected growth rates for selected products through 1990.

The forecast for basic petrochemicals (ethylene, propylene, benzene) shown in Table I and based on the conservative growth rates referred to above, indicates that Alpetco's production will represent a relatively small share of the industry.

Table I

Forecast of U.S. Demand for Basic Petrochemicals (billions of pounds per year)

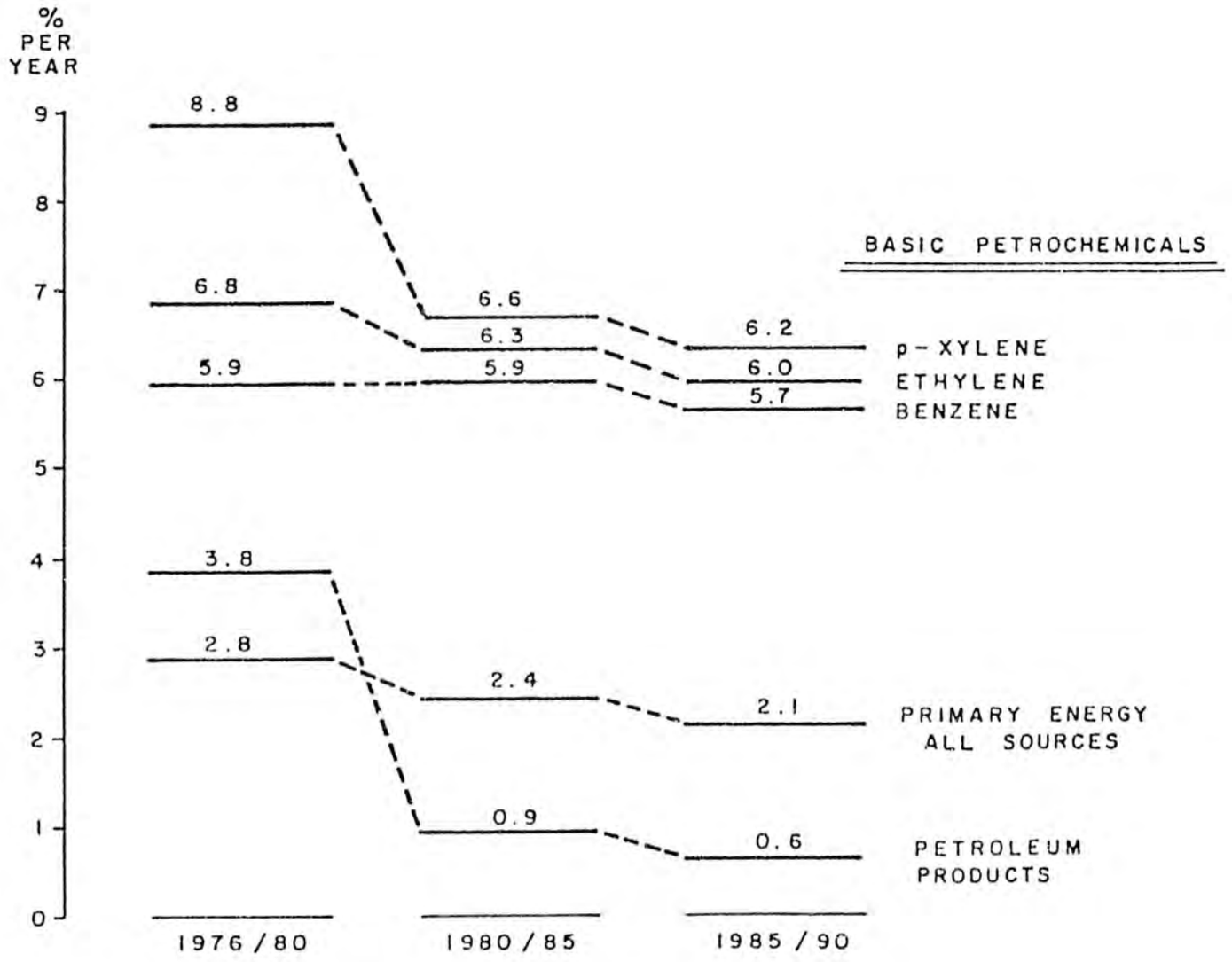
Year	Ethylene	Propylene	Benzene
1980	31	15	13
1990	53	28	21
2000	85	47	33
Alpetco Case LE-1	1.2	0.7	1.0

Source: Chem Systems Inc.

AGO 545802

Chart A

FORECAST GROWTH RATES
PETROCHEMICALS VS. FUEL PRODUCTS



Source: Chem Systems Inc.

AGO 545803

The relevant market in the U.S. for Alaska petrochemicals is on the West Coast because this market has lower transportation costs from Alaska, strong growth, and no planned new capacity. In fact, despite the substantial and growing West Coast market for petrochemicals, there are no major existing facilities on the West Coast which manufacture petrochemicals. Chart B indicates that demand for petrochemicals substantially exceeds present supply and this imbalance worsens in the future.

A very conclusive illustration of the need for petrochemicals in Alpetco's relevant market area is shown in Table II below. Alpetco intends to build one "world-scale" ethylene plant while the market will grow to a level requiring ten such new plants.

Table II

New World Scale Ethylene Plants Needed

	U.S. West Coast	Other Pacific Basin
1976-1985	3	2
1985-1990	1	4
	4	6

Source: Chem Systems Inc.

Alpetco initially plans one world-scale plant

Chart B

U.S. WEST COAST

SUPPLY-DEMAND

SELECTED PETROCHEMICALS

MILLION POUNDS

	1976	1980	1985	1990
Ethylene for Major Derivatives				
Supply (1)	250	250	250	250
Demand	1725	2435	3455	4500
Low Density Polyethylene				
Supply (1)	120	120	120	120
Demand	710	1000	1400	1900
Styrene				
Supply (1)	0	0	0	0
Demand	500	742	1085	1590

NOTE:

(1) Currently installed capacity only

AGO 545804

WHAT WILL BE THE IMPACT OF THE ALPETCO PROJECT ON THE U.S. AND PACIFIC BASIN MARKETS?

Alpetco's petrochemical output will not represent a significant share of the U.S. and Pacific Basin markets by the time the project is operational. Based on one possible configuration of Alpetco's facility the company would have no more than 3 to 4% of the 1985 estimated market for aromatics (benzene, toluene, xylene) or olefins (ethylene, propylene, butadiene). Further, Alpetco's market share of downstream products would also be quite low.

Table III

Expected Market Share of Alpetco's Facility in 1985

Product	Normal Plant Size	% of U.S. and Pacific Basin Markets
Low Density Polyethylene	600 MM lbs/year	4%
High Density Polyethylene	300 MM lbs/year	3%
Polypropylene	400 MM lbs/year	4%
Styrene	800 MM lbs/year	6%

Source: Chem Systems Inc.

DOESN'T ALPETCO JUST WANT ALASKA'S ROYALTY OIL BECAUSE THERE WILL BE A SHORTAGE OF OIL SOMEDAY?

The contract provides that Alpetco may not purchase any royalty oil unless and until it has obtained financing commitments for $1.5 billion. This is a crucial "benchmark" and is designed to be the "go/no-go" measure in the contract.

The Alpetco contract requires that the company develop a petrochemical facility in Alaska according to a rigorous timetable. Failure to meet each and every requirement gives the State a right to terminate the contract. Alpetco's only reason for purchasing royalty oil is for use in a petrochemical facility to be built in Alaska.

HOW DOES ALPETCO EXPECT TO FINANCE THE PROJECT?

The project will be financed by a combination of bank revolving credit, medium and long-term debt, both taxable and tax-exempt, supplier credits and foreign export bank financing. The long-term taxable debt will be supplied by private placement issues with major life insurance companies, pension and profit-sharing and retirement

AGO 545805

funds. The tax-exempt portion of the project, which could include as much as $350 million, will be placed with casualty insurance companies and commercial banks. The availability of tax-exempt financing is beneficial to Alpetco since it can lower Alpetco's interest rate by as much as 2 percent versus regular taxable debt.

Since the project will be phased, the requirements for long-term financing will be spread out over several years and thus give the institutional markets time to digest the debt. This is the same type of program as carried out with other large project financings common to the financial community.

Alpetco's financial advisors, E. F. Hutton and Lehman Brothers, Kuhn Loeb, have given their opinion that the project is financible and that any needed equity for the project can be raised.

Alpetco as well as E. F. Hutton and Lehman Brothers, Kuhn Loeb expects that several major chemical companies may participate in the project either through purchase agreements, joint ventures or other forms of participation. Such involvement by major chemical firms is quite typical in large petrochemical ventures and will improve the financibility of the project.

Construction financing for the project is being arranged by Chemical Bank (New York). Chemical Bank will be lead bank for a banking group that will provide working capital and construction financing for Alpetco and has already committed $150 million of its own resources towards the necessary debt financing of the project.

WHERE WILL THE STATE SELL THE OIL TO ALPETCO?

At Pump Station #1, on the North Slope.

WHO IS RESPONSIBLE FOR GETTING THE OIL FROM PUMP STATION # 1 TO THE ALPETCO FACILITY?

Alpetco is. Since the trans-Alaska pipeline is a regulated public carrier, Alpetco will deliver its oil to the pipeline companies for shipment to Valdez. Alpetco will pay published pipeline tariffs directly to the various pipeline companies. Alpetco will also be responsible for transporting the oil from the end of the TAPS pipeline to its facility. This will be by pipeline if the facility is in the area of Valdez or by specially built tanker or ocean going barge if the facility is not near Valdez. All costs of this transport will be paid by Alpetco.

AGO 545806

BECAUSE CRUDE OIL WILL BE SCARCE IN THE FUTURE, WON'T ALPETCO BE GETTING A BARGAIN?

Alpetco agrees that crude oil may well be in short supply in the future. It is this fact that makes the long-term contract to purchase Alaska's royalty oil valuable to Alpetco. However, the price Alpetco will pay for royalty oil will always be the same price that the producing oil companies would have paid the State "in value." This price is the same as what the non-royalty oil is sold for in the market place; therefore, the price will always reflect current value of the oil. If oil prices rise in the future, then Alpetco will pay the State of Alaska that higher price. There will never be any "bargain" in price.

WILL ALPETCO COMPLY WITH STRICT ENVIRONMENTAL STANDARDS?

The company has agreed in its contract to abide by all state or federal laws and regulations and in addition has agreed to a number of supplemental state standards, whether or not required by law.

WHAT ARE THE BENEFITS OF THE ALPETCO PROJECT TO THE STATE OF ALASKA?

There are many. The Alpetco project is a unique opportunity for Alaskans to use their natural resource. . .royalty crude oil. . .to create long term and very valuable benefits. No other state has ever had an opportunity so great.

Some of the benefits to Alaska are:

No risk to the State of Alaska
No subsidy to Alpetco
Additional employment
Additional tax revenues
Alaska Endowment Trust
Shipping by Alaskans
Specialized job training
Local hire
Controlled industrial development

AGO 545807

No Risk to the State of Alaska; No Subsidy to Alpetco

Alpetco will not purchase royalty oil unless and until it has obtained financing commitments for $1.5 billion, which clearly indicates that the petrochemical facility will be built.

Alpetco has already received a favorable opinion from the Department of Energy establishing the right of the State of Alaska to terminate sales of oil to Alpetco if Alpetco does not fulfill its contractual obligations. Without this DOE opinion, the State would not be protected because certain federal regulations would have acted to require the State to continue honoring a "supplier-purchaser" relationship. Under the opinion obtained by Alpetco on behalf of Alaska, the State has no risk.

Alpetco and the State have agreed to performance benchmarks which are designed to measure the progress made by Alpetco in building the petrochemical facility. Failure by Alpetco to attain each and every benchmark results in a right by the State to terminate Alpetco's contract. Chart C summarizes the performance benchmarks. The 18 month check point (eighteen months after the legislature ratifies the contract) is the most important one. This is the "go/no-go" benchmark. If Alpetco is unable to put together the project by the 18 month benchmark, the State may terminate the contract.

Additional Employment

The project offers excellent long term employment opportunities for Alaskans. The petrochemical industry provides year around jobs with excellent wages. The many categories of jobs create good opportunities for training and career development.

Preliminary planning estimates for new permanent jobs at the petrochemical facility are shown in Table IV.

AGO 545808

CHART C

NO RISK TO ALASKA: PERFORMANCE BENCHMARKS

Contract May Be Cancelled by State If Alpetco Fails to Attain Each Benchmark as Follows:

Time Period	Required Performance
1st 6 months	Monthly progress reports to the State
Thereafter	Quarterly progress reports
6 months	$2 million invested Site selection Begin optimization design
12 months	$3 million invested
18 months	$10 million committed Contracts for sale of 70% of output Get financing commitments for $1.5 billion Complete Environmental Impact Assessment File for permits Finalize plant design
24 months	$100 million committed
30 months	Commence construction
36 months	$600 million committed
48 months	$1 billion committed
60 months	$1.2 billion committed
72 months	$1.5 billion committed

AGO 545809

Table IV
New Permanent Jobs

	Minimum	Maximum
Refining	450	550
Aromatics units	250	300
Olefins steam cracker	300	375
Polyethylene units	400	575
Polypropylene units	250	350
General works management	75	75
Contract help	200	250
Total refinery related jobs	1,925	2,475
Shipping	250	350
Total permanent jobs	2,175	2,825

During the construction phase (3½ years), from 3,500 to 4,000 workers will be needed. Many of these workers will be able to remain as operators and maintenance workers at the facility if they desire.

The shipping activities of Alaska Consolidated Shipping will provide permanent jobs for 250 to 350 Alaskans.

In summary, the Alpetco project is expected to create 2,175 to 2,825 new permanent jobs for Alaska.

Additional Tax Revenues

Because of the large investment in a petrochemical facility, a substantial tax base will be created by Alpetco. The company's financial projections show that an average of more than $49 million will be paid annually to state and local governments by Alpetco. Table V shows the various categories and expected tax revenues from the project.

AGO 545810

Table V
Direct Tax Benefit to Alaska*

	$ Million — Estimated** — Average Per Year	Total Contract Period
Property Taxes (@ 1%)	$23	$ 612
State Corporate Income Tax	23	632
Gross Receipts Tax	3	90
	$49	$1,334

*Does not include estimate of personal income taxes paid by Alpetco employees or any taxes paid by support business or employees of support businesses.

**Source: March 10, 1978 analysis for Institute of Social and Economic Research.

Alaska Endowment Trust

Alpetco's contract provides that beginning with the eleventh year after start-up of the plant, 5% of the company's after-tax profits will be contributed to a charitable trust fund to further social, education, cultural and environmental conditions in Alaska. The Alaska Endowment Trust will be administered by trustees unaffiliated with Alpetco. The company expects that its contributions to this public welfare trust will qualify under present IRS rules as a charitable donation and therefore be deductible for federal tax purposes.

Alpetco believes it is important for corporations to be good citizens and the Alaska Endowment Trust provides an excellent means of contributing to the community.

Shipping by Alaskans

As Alpetco's shipping arm, Alaska Consolidated Shipping will provide specialized ships for transportation of dry and liquid bulk petrochemicals. The activities of ACS will provide career opportunities for Alaskan citizens in the maritime industry. ACS is backed up by Seatrain Lines, Inc., one of the largest shipping companies in the United States. The firm is experienced in all phases of shipping including port management and personnel training.

AGO 545811

Specialized Training for Alaskans

Through its affiliate, Alaska Consolidated Shipping, Alpetco is already training future employees in the shipping and refinery industry. Four Alaska Natives are presently in training, two at the Harry Lundeberg School at Piney Point, Maryland and two at Pride Oil Refinery at Abilene, Texas.

Extensive training programs for Alaskans are planned in all phases of shipping, plant operations, and plant maintenance. These training programs will be coordinated with Brown & Root, Chem Systems Inc., local labor unions and with the State of Alaska.

Labor Policies

Alpetco's project manager, Brown & Root, Inc. will operate in Alaska through its subsidiary, Alaska Constructors, Inc., and will comply with all applicable State local hire provisions.

Alaska Constructors is experienced in working with local unions and subcontractors in Alaska and is well thought of in the industry.

By working closely with local agencies, Alaska Constructors will make every effort to phase construction employees into permanent jobs.

Controlled Industrial Development

The petrochemical industry is clean, environmentally safe, and attracts new businesses that thrive on the foundation which petrochemicals bring to the economy. With a high capital investment per employee, the industry requires skilled, well-educated employees who are responsible citizens and who often are leaders in their communities.

AGO 545812

WHY SHOULD THE PROJECT BE SUPPORTED IN ALASKA?

The following editorial in *The Anchorage Times* clearly stated why petrochemicals should be supported in Alaska.

The Anchorage Times, Sunday, February 19, 1978



Royalty Oil Decision

By Robert R. Richards

THIS WEEK the administration is to deliver to the Legislature its recommendation regarding disposition of the state's royalty oil.

Although several experts have questioned the viability of the four proposals before the Royalty Oil and Gas Development Board, it should be noted that the four bidders have been working closely with the state over the past few months to develop plans that make sense for all parties. Now consultants Bonner and Moore Associates Inc. have concluded that at least three of the four contenders are "fully qualified."

It seems to me that anyone concerned about the stability and long run health of Alaska's economy should give careful consideration to this marvelous opportunity to expand the vertical integration of Alaska's industrial base. Our woefull lack of in-state processing of our resources has contributed to chronic abnormal fluctuations in Alaska's economy. Expanding the manufacturing operations in Alaska will help create a more stable and therefore more socially healthy economy in Alaska.

Additionally, the petrochemical industry brings substantial benefits far beyond those of many other industries. It is highly capital intensive and one of the lowest labor intensive industry of any of our nation's basic industries. Therefore, expansion by the petrochemical industry results in very little population impact. The highly automated petrochemical operation requires very few workers and therefore imposes very little additional burden on public services, such as schools, hospitals, highways, etc.

SO IT IS very clear to see that the petrochemical industry, relative to other potential industries, imposes a very small social cost. But what about the other side of the coin? What does this industry do in the way of creating social benefits?

Again, in this regard the petrochemical industry is a star performer. Its first sociall benefit results from its employing highly skilled, well educated, and high paid employees. These people generally have a high participation rate in community affairs. Their high incomes are taxed commensurately high, and their socio-economic station in life geneally implies fewer social problems in the sense of crime, disease and the like.

The second social benefit emanating from the petrochemical industry is its contribution to creating a more stable economy. The industry is virtually non-seasonal. As we all know, those plants down on the Kenai Peninsula keep producing 365 days out of the year. Alaska's other basic industries, fishing, forest products and tourism, are highly seasonal industries. As a result typically employment in Alaska in January is one-fourth below the level of employment in July. Such seasonality creates all sorts of problems. The expansion of the petrochemical industry in Alaska will help considerably to reduce the overall seasonality of employment in our state.

ANOTHER WAY in which industry employment varies is the swings from year to year. This phenomenon, of course, is referred to as the business cycle. Again, Alaska's fishing and forest products industries are highly cyclical industries. The petrochemical industry, on the other hand, experiences considerably less cyclical fluctuation.

Therefore, the expansion of the petrochemical industry in Alaska would reduce both the seasonal and cyclical fluctuations in our economy, bringing about a considerably more stable employment situation.

The third major social benefit from the petrochemical industry results from the huge taxes and other forms of government revenue generated from this industry. The key factor here is that revenue flowing to both state and local government exceeds by far the additional burden which the industry and its employees place on state and local government. So there are all sorts of excess funds available for the pursuit of a whole array of social objectives: parks, bike paths, better schools, better health care, and on, and on and on.

This then, is what leads me to a very important conclusion which we should keep clearly in mind. It is simply this: because of the huge public revenue generated by the petroleum and petrochemical industries this type of economic growth is not only compatible with, but indeed is conducive to the pursuit of the whole array of our non-economic objectives.

Perhaps I can summarize by acknowledging the general positive relationship between our "quality of life" objectives and our economic development. Here we have the opportunity to encourage an industry which will bring wages, highly skilled, well educated people to stable employment and which manyfold more than pays it own way in terms of social impact. The social and economic attractiveness of the petrochemical industry is self-evident.

Robert R. Richards, an economist, is executive vice president of Alaska Pacific Bank.

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AGO 545813

ARE THE ALPETCO PROJECT AND THE PROPOSED NATURAL GAS PIPELINE IN CONFLICT?

Very simply, no. In fact, if the proposed gas pipeline goes forward and it becomes economically feasible to ship gas liquids down the line for processing in Alaska, Alpetco will be interested to work together with such a project to mutual advantage. This is the kind of cooperative development that has helped petrochemical development on the U.S. Gulf Coast to flourish. Alpetco wants to have the same degree of cooperation here in Alaska.

IS THE "MAKE-UP" PROVISION GIVING ALPETCO THE RIGHT TO PURCHASE ROYALTY OIL FROM LEASES OTHER THAN PRUDHOE BAY NECESSARY?

Yes. A secure, long-term supply of crude oil feedstock is the basis upon which the Alpetco project is built. The economics of this petrochemical plant necessitate an average daily supply of approximately 150,000 barrels and requires a $2.5 billion investment.

Confronted with the fact that the State of Alaska ultimately determined to sell only 85% of its share of Prudhoe Bay oil, Alpetco sought on advice to "make-up" any shortfall by purchasing royalty oil from other leases. Although the State reduced this request for all other royalty oil to be satisfied out of only 70% of other royalty oil, Alpetco's financial advisors have stated that this provision is a prerequisite to the financing.

The shortfall may be a small quantity; it may never be needed. It is, however, necessary to underpin the economics of the project.

WHERE WILL ALPETCO BUILD THE PETROCHEMICAL FACILITY?

The company has not yet identified a site on which to build. Preliminary study suggested that a site on the Kenai Peninsula, near Nikiski, would offer the most advantages to the community and Alpetco; however, the company will conduct a thorough site analysis prior to selecting a site.

Alpetco must choose a site within six months after the legislature approves the contract. Following Alpetco's selection, the State will conduct public hearings to determine local opinion about the site.

Alpetco has not ruled out any sites but will rely on its experts for an in-depth site study to be conducted immediately after legislative approval is received.

AGO 545814

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RECEIVED
FEB 27 1978
Department of
Natural Resources

February 21, 1978

Frederick H. Boness, Esq.
Deputy Commissioner for
Dep't. of Natural Resources
Pouch M
Juneau, Alaska 99803

Re: State of Alaska w Alpetco

Dear Fred:

I have reviewed the Alpetco draft of February 8, 1978 and revised pages sent to me by Telecopier a few days ago. My principal comments on this amended draft are:

1. Article 1.1 omits "or direct or indirect common ownership interest".

2. The first sentence of Article 2.3 covers transportation costs. What about other costs?

3. Art. 2.4 requires the State to obtain advance written consents from future purchasers. You realize, of course, that the Alpetco interpretation by the D.O.E. does not apply to sales to other purchasers. Individual interpretations will be needed to validate each such consent.

4. In Article 3.3 (last sentence) the buyer will transport the oil "to the Petrochemical Facility". Since the delivery of oil may start before the Facility has been built, these four words should be deleted.

5. In Article 5.3, the State agrees to bear the cost of the litigation. Also is the storage capacity to be at the "Point of Delivery" if the Point of Delivery is Station #1?

6. The last words of the first sentence of Article 6.1 have been objected to several times, but are still there. What happens if the oil does not meet the TAPS specifications? If this happened, then presumably the other 7/8 of the oil would also not meet the specifications, which is hard to conceive, but if it happened, what would we (or the lessees) do with the oil?

7. Article 8.1.1 refers only to one litigation. Suppose other suits are brought to clarify the dispute? Why is only this one suit singled out? (See also Article 9.5).

8. In Article IX reference is made to subsequent adjustments of the price, possibly years later. Does this not require a ruling of the D.O.E. as to its validity, in the light of Mr. Gerarden's statement to Mr. LeResche?

9. Article XII raises the most problems.

(a) I recommend that the following be added (for clarification) at the end of the second sentence of Article 12.1. "***but the said security interest shall attach to the account receivable arising therefrom and its proceeds".

(b) Since we know the TAPS tariffs prohibit liens on the oil, the State must be sure to get written waivers before agreeing to this, otherwise the "purchase money" lien on the oil (which is your principal protection) would be effectively eliminated merely by the posting of a bond for the value of the oil in the pipeline, in accordance with the third sentence of Article 12.1. The agreement purports to re-grant the lien at Valdez, but then it would no longer be a "purchase money" lien and the oil would be subject to all previously filed or possessory liens.

(c) Subdivision (ii) of the third sentence of Article 12.1 raises a different question. The State's lien was intended to cover all oil and all accounts receivable to secure payment of all sums due. This is a form of cross-collateralization necessary to protect the seller. Mr. Rogers has tried to turn this into separate liens on individual shipments (like mortgages on automobiles bought by a dealer). This was not discussed or, I believe, understood by the State. This will be a running account, with payments being made substantially after delivery. How could any payment be traced to any particular oil? I doubt that any records would be kept showing what oil was being paid for each time a payment is received.

Let us assume that the Buyer has received $20,000,000 of oil at its facility and an additional $20,000,000 of oil is

in the pipeline. The Buyer then sells the oil on hand and pays $20,000,000 to the State, with a notice saying "this sum is in payment of all oil in the pipeline". In that event, the pipeline oil would be free of lien, the previously delivered oil (which had been sold to raise the $20,000,000) would be free of lien (see sentence 2 of Article 2.1), the account receivable derived from such sale would have been paid, and the money would have been used to pay the State. Result: there would be no security for payment of the purchase price of the first $20,000,000 of oil, which remains unpaid.

The entire concept of breaking up the deliveries and payments, of segregating accounts and credits, of individual liens (rather than a total "floating" lien on everything), could make the security provision unworkable, and should be resisted.

(d) The fourth sentence makes no sense to me. If delivery is at Station #1, this sentence should be ~~deleted~~. Corrected It seems to be in error in view of the fifth sentence which refers to the "next preceding sentence", which must mean the third sentence (discussed above), and not the fourth sentence.

(e) The last sentence of Article 12.1 should contain the usual power of attorney by the Buyer to the Seller, authorizing it to execute in the Buyer's name and file all necessary financing documents. This sentence also ties into the assignment problem discussed below.

(f) The following clarification should be added at the end of Article 12.1: "Proceeds of the sale shall include proceeds derived from insurance or other payments resulting from damage to or destruction of the oil or property covered by the security interest. To secure such payment, Buyer will cause all policies of insurance on the oil or other property to which the security interest attaches, to name the Seller as co-insured as its interest may appear."

10. Article 12.2 no longer refers to a fixed amount of alternative security.

(a) What does "substantially reflect the amounts" mean? Does it mean "be equal to"? Also, why not say it?

(b) More important, if the Buyer owes nothing at a particular time, but is buying $50,000,000 the next month, the security would be zero because the security is only to cover sums "owed", not "to be owed".

11. Article 14.1 (v) should read "bankruptcy or other proceeding".

12. Under Article 14.3 is Buyer's failure to meet the time schedule of Article 10.2 a material and substantial breach?

13. As I told Cynthia on the telephone, Article XVIII should be amended to require delivery of periodic financial statements (not less than quarterly) as received by Buyer. The bank will no doubt have the same requirement, so that should be no hardship.

14. Article XXIII raises questions previously discussed.

(a) If the agreement is assigned to a Trustee (who is not required to "assume" the agreement, e.g., it need not promise to build the refinery), the Trustee should, at the very least, be required to agree to the security provision and to sign and file necessary UCC-1 forms to evidence the fact that it is holding the assets subject to the State's purchase money security interest. The important question is one of substance: Is it contemplated that the Trustee's lien will be paramount to, or subordinate to, the purchase money lien? If the State comes first, this should be made evident.

(b) The last sentence of the paragraph makes it clear that the Trustee, on foreclosure of its lien, can assign this agreement to anyone (subdivision iii) without the State's consent. Would it not be embarrassing if the assignment were to a foreign interest which could shut the plant down? Or to a convicted felon? Should not the State have a reasonable voice as to the assignee of its agreement?

15. Article 26.7 again raises the question we have discussed several times: are you prepared to make all decisions justiciable? For example, if extensions of time under Article 10.2(10) are not granted, is this "reasonable"? I asked Mr. Rogers to specify the paragraphs to which he wanted the test of reasonableness to apply, but he retains the over-all approach, and wants the State to be "reasonable" (i.e., subject to court review) with regard to all of its actions. This could bring into litigation, for example, the standards set forth in Exhibit D.

Please call me if you have any questions concerning these comments.

Best personal regards.

Sincerely,

Eugene M. Kline

EMK:blg

cc: Commissioner Robert LeResche

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[illegible] 2, 1978
Department of
Natural Resources

February 21, 1978

Frederick H. Boness, Esq.
Deputy Commissioner for
Dep't. of Natural Resources
Pouch M
Juneau, Alaska 99803

Re: State of Alaska w Alpetco

Dear Fred:

On rereading my letter of even date, I noted an error. Paragraph 9(d) should read: "this sentence should be corrected."

I suggest that the following be added at the end of the sentence in question (sentence 4 of Article 12.1) to effectuate this correction:

> "*** or prior to the attachment of Seller's security interest thereto upon such delivery."

Since this sentence is not self-operating, I suggest that the following be added: "Buyer also agrees that it will not grant, or consent to, any security interest in favor of any third party, unless such third party agrees in writing prior thereto that such security interest is subordinate to the security interest of the Seller, and unless written proof of such subordination is delivered to Seller prior to the Buyer's granting or consenting to such security interest.

Sincerely,

Eugene

Eugene M. Kline

EMK:blg

cc: Commissioner Robert LeResche

AGO 545820

SCOMM

#16:2

INTERIM REPORT

AND

written

TESTIMONY SUBMITTED TO JOINT GAS PIPELINE impact COMMITTEE

PUBLIC HEARINGS

FEBRUARY 17 - 20, 1976

AGO 545821

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INTERIM REPORT
OF THE
JOINT GAS PIPELINE IMPACT COMMITTEE

This Committee, through public hearings and staff investigation, has become convinced that immediate action by the State of Alaska is essential if the citizens of this State are to receive maximum benefit from the State's natural gas resource.

The Committee will issue a full and complete report on its findings and recommendations at a later date, but is impelled to submit this interim report to the Legislature and the people of the State of Alaska because of the urgency of the present situation.

The Committee finds and concludes the following:

1. A federal decision authorizing the transportation of North Slope natural gas across Canada would be inimical to the interests of the State of Alaska. The State's resource would be drained, its people denied access to a premium fuel and raw material, its work force deprived of employment opportunities, and productive economic growth would be thwarted.
2. A federal decision authorizing the transportation of North Slope natural gas across the State of Alaska to an open port will serve the best interests of the State.
3. The level of benefits, and burdens reasonably to be expected by the State as a consequence of any decision on a North Slope gas transportation system are of such magnitude that the routing decision must be regarded as critical to the future of the State. Action to secure a Trans-Alaska routing must be pursued as expeditiously as possible; no reasonable step should be left untaken.
4. The position of the state as owner of a one-eighth royalty in natural

gas and natural gas liquids produced from State-owned lands on the North Slope creates an immediate opportunity for effective State action which can assist in securing a Trans-Alaska transportation system.

5. Affirmative, agressive action by the Governor, the Commissioner of Natural Resources, the State Royalty Board, and the Legislature with respect to the State's royalty gas is imperative.

6. Effective use of the State's royalty gas, to serve the best interests of the State, requires:

   a. The State must elect to take its royalty share of natural gas and natural gas liquids in kind.

   b. The State must commit a portion of its royalty gas to purchasers who will assist in securing approval of a Trans-Alaska transportation system, and who will thereafter utilize such a Trans-Alaska system.

7. Present levels of natural gas demand in Alaska permit a commitment of a portion of the State's royalty gas to purchasers outside the State; while every effort must be made to retain a substantial part of Alaska's gas for present and future in-state needs, it is in the overall best interests of the State to offer for sale outside the State, a substantial portion of the State's royalty gas to purchasers who can, and will, assist in securing authorization of a Trans-Alaska transportation system.

8. Those persons and firms interested in the construction and operation of a Trans-Alaska transportation system can materially alleviate State unemployment problems, and the State should, in striking a bargain for the commitment of State resources to a Trans-Alaska

system, secure appropriate commitments for the hire and training of Alaska residents in the construction and operation of such a system.

9. Finally, the risk that non-action by the State, or delayed action by the State, will cause the selection of a Trans-Canadian routing, and the risk that the State will lose substantial benefit of its natural gas resource are so great, it is the sense of this Committee that State action must not be delayed.

BY REASON OF THE FOREGOING, IT IS THE RECOMMENDATION OF THIS COMMITTEE THAT:

1. The commissioner of Natural Resources and the State Royalty Board should undertake immediate negotiations with interested out-of-state purchasers to reach definitive sales and/or exchange agreements covering disposition of substantial portions of the State's royalty gas on the best obtainable terms.
2. The Commissioner of Natural Resources and the State Royalty Board should undertake immediate negotiations with natural gas transporters involved in the proposal for a Trans-Alaska system to reach definitive transportation agreements covering the State's royalty gas sold for out-of-state use, and the State's withdrawal of the unsold portion of its royalty gas from the system for in-state use; appropriate commitments should be obtained with respect to hire and training of Alaska residents.
3. The arrangements and agreements so negotiated should be presented to the Legislature for ratification prior to the end of the Second Session of the Ninth Legislature to avoid, if possible, a special session.
4. The Legislature should hold itself ready for immediate consideration

of and prompt action on, the recommendations of the Commissioner and Board.

5. Such arrangements, contracts, and agreements as are negotiated by the Commissioner and Board and approved by the Legislature should be incorporated into the pending applications for a Trans-Alaska transportation system, presented to the Federal Power Commission by the appropriate transporter-applicant, and approval thereof obtained in the pending Federal Power Commission proceedings.
6. The Legislature should adopt SCR 66 and further seek the active cooperation of all owners of North Slope gas in support of the Trans-Alaska pipeline route.

Alaska State Legislature

Senate

JUNEAU, ALASKA

A G E N D A

GAS PIPELINE IMPACT COMMITTEE

PUBLIC HEARINGS

FEBRUARY 17, 18, & 19 - Supreme Courtroom A, 1-5 PM

FEBRUARY 17

1:00 PM NBC Whitepaper "Natural Gas"

1:45 PM Rush Moody Jr.

3:00 PM George Sellides - Uses of Natural Gas in Alaska

3:30 PM Anchorage Natural Gas, Dale Teel

4:00 PM OMAR

4:30 PM BP Alaska, Joe Josephson

FEBRUARY 18

1:00 PM Legislative Committee on Taxation and Revenue

1:30 PM Wentworth Brothers, J.J. Schons

2:30 PM Fairbanks Industrial Corporation,
Associated General Contractors, Conrad Frank

3:00 PM National Electrical Contractors Association, Julius Kornfiend

3:30 PM Federal Labor Council of Fairbanks, Dave Rasley

4:00 PM Anchorage Municipal Light and Power, Tom Stahr

4:30 PM State of Alaska, Patrick Dobey

AGENDA
Page -2-

FEBRUARY 19

1:00 PM State of Alaska, Guy Martin, William Fackler, Easy Gilbreth

2:00 PM El Paso

3:00 PM Tenneco

3:30 PM ARCO

4:00 PM Exxon

4:30 PM Collier Chemical Corporation

6,000 4,000,000 24,000,000,000,000

NATURAL GAS FACT SHEET

4-5 billion barrels of oil

SADELROCHIT RESERVOIR

Estimated reserves= 26 to 32 Trillion Cubic Feet (TCF)
Estimated daily flow from pipeline= 2.5 Billion Cubic Feet* (BCF)
Estimated yearly flow = .9 Trillion Cubic Feet

Alaska's royalty share= 3.25--4 TCF
Daily royalty share = 312 Million Cubic Feet (MMCF)
Yearly royalty share = 114 BCF

*Department of Interior study.
More proven reserves are expected to be proven in the North Slope area.

ALASKAN USE

Almost all the natural gas used in Alaska is in the Cook Inlet area.

Anchorage Natural Gas uses about 30 BCF per year.
That is equal to 12 days production from Prudhoe Bay.
On a cold day in Anchorage, about 120 MMCF is used.
Anchorage Natural Gas has firm commitments for 10--15 years of gas from Cook Inlet.

Phillips Petroleum uses about 61 BCF per year, most of which is liquified and shipped to Japan.

Collier Chemical Corporation uses about 21 BCF per year in their Ammonia/Urea plant. They are now doubling their operation.

One thousand cubic feet of gas (1 MCF) is equal to about 1 Million BTU. North Slope gas is particularly "rich" at about 1.1 MMBTU.

Six MCF of gas is roughly equal to one barrel of oil.

Consumers are willing to pay a premium for gas. It is a clean energy source.
On strictly energy equivalent, $2.00 per MCF gas = $12 barrel oil.
Considering the advantages of using gas, $2.00 gas = $9 barrel oil.

United States gas production has declined from a peak of about 62 BCF per day in 1973 to 55 BCF/day in 1975.

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PARIS 8, FRANCE

January 14, 1976

Senator John Rader, Chairman
Joint Gas Pipeline Impact Committee
The Legislature of the State of Alaska
Juneau, Alaska 99801

Dear Senator Rader:

Your Committee has asked me to address certain issues relative to the transportation of Alaska natural gas, assuming for the purpose of my analysis that there will be gas available for sale from the North Slope. 1/

I propose to set forth in this letter the conclusions that I have reached as a result of my research and my knowledge of the Federal Power Commission, together with certain alternatives which the State might wish to consider. To this letter I will append the legal analysis which leads to the conclusions expressed herein.

1/ You are aware of the possibility that natural gas production for sale may have a detrimental effect on the recovery of oil. Studies conducted by the Department of the Interior and by H.K. Van Poolen and Associates raise questions in this regard which are now being examined by the Committee. This issue is, I agree, of critical importance to State consideration of natural gas transportation issues, inasmuch as the State may find it necessary, for reasons of conservation, to limit natural gas production or require reinjection of associated natural gas for maintenance of reservoir pressure. Such conservation actions are, in my opinion, legally permissable if necessary to prevent waste, see pp. 85-94 of attached analysis, but might result in an indefinite postponement of a natural gas transportation system.

From the outset, I need to make clear my recognition, that State policy relative to natural gas will develop, as it should, through processes of government, and that these policy decisions will involve consideration of far more than questions of law and Federal policy. What I offer can be only a part of the whole which the State will consider as the State moves forward to a sound an productive policy of resource management. 2/

As a substantive starting point in my report to you, it is my judgment that the State should, from the standpoint of legal consequences, decide as quickly as possible the ultimate goals of State natural gas policy. If the State has a strong concern for a retention of a portion of Alaska gas for future Alaska needs, affirmative and aggressive State action will be necessary. Non-action by the State with respect to disposition and transportation of North Slope natural gas threatens permanent loss of the gas resources insofar as Alaska consumers are concerned; non-action creates a risk that natural gas produced in Alaska will not be available to fulfill future Alaska residential or industrial needs.

Let us assume that the El Paso, Trans-Alaska transportation route is authorized. Non-action by the State will result, sooner or later, in producer sales of eight-eighths of the natural gas stream in interstate commerce, either to an interstate pipeline, to distributors in the lower 48 states, or to direct users in the lower 48 states; and non-action by the state will result in the construction and operation of an interstate transportation system designed for, and financed on, the expectation of the flow of eight-eighths of the deliverable natural gas from the North Slope. If the State permits, by non-action, these developments, then certain legal consequences may be expected.

2/ I would ask it to be understood that my opinions do not reflect considerations outside my area of knowledge and training; I have no basis, for example, for advice on environmental or economic factors; nor can I gauge the will of the citizens of Alaska concerning economic growth and industrial development; nor can I estimate how strong will be the demand for revenue because of programs which the State may determine are necessary.

The issues which I address are, therefore, approached only from the relatively narrow standpoint of law and Federal regulation. I do not presume to prescribe what is "right" or "good" for the State. These determinations are peculiarly within the province of this Legislature, which will, I am sure, look to a much broader range of considerations, information, and analysis than are within my capabilities.

1. If producers market Alaska natural gas in interstate commerce, paying the State a one-eighth royalty in cash, the Federal Power Commission can assert jurisdiction over eight-eighths of Alaska production, and thereby attempt to prevent any later efforts by the producers, or by the State, to withdraw the State's one-eighth royalty share for an in-kind taking by the State for use in the State. (pp. 64-73) 3

2. In the event of such a sale by producers to an interstate pipeline, and in the event of FPC denial of a request to withdraw State royalty gas, the only means for securing gas service in Alaska would be through a future demand by Alaska municipalities or distributors for service by the pipeline; such a request may be treated by the FPC, and lower 48 pipeline or distributor customers, as a request for new service which cannot lawfully be authorized. If the pipeline, at the time of the demand, is unable to render adequate service to its non-Alaska customers, or if grant of the Alaska demand would require to enlargement of pipeline transportation facilities, the Commission may be required, by law, to refuse demands for Alaska service -- even for residential and public service needs.

3. If Alaska can successfully claim -- contrary to the hypothesis in Paragraph 2 -- status as an existing customer, pipeline natural gas supplies would be shared by Alaska and non-Alaska customers on the basis of FPC curtailment priorities and allocation orders.

4. In the event of direct sale by producers to end users in the lower 48 states, or sale to distribution companies in the lower 48 states, there is no clear legal mechanism available to the State of Alaska to secure any portion of the natural gas produced in Alaska for future Alaska needs as they may develop.

Non-action by the State, in my judgment, creates serious risk that Alaska natural gas will not be available for future Alaska needs, even if the El Paso transportation proposal prevails. It is not just the

3/ Page references here and later in this letter are to the attached legal analysis.

potential industrial gas demand (which may or may not be a matter of State concern, dependent on the will of the citizenry with respect to industrial development) that is at risk. The needs of Fairbanks, and other communities, for residential service and service to schools, hospitals, and the like is also threatened.

The risk can be lessened by appropriate State action, as hereinafter discussed, if a trans-Alaska routing is authorized. If a trans-Canada routing is selected, whereby North Slope natural gas leaves Alaska north of the Arctic Circle, the State has no means of protecting its future gas needs. The routing question is, therefore, critical to the State -- at least in the context of future availability of Alaska gas for future Alaska needs. 4/

I am of the firm opinion that neither of the present proposals for transportation of North Slope natural gas offers a substantial guarantee that Alaska natural gas needs will be met. If either the El Paso or the Arctic Gas proposal is approved as presently submitted, the State could well find itself unable to draw upon its own gas resources to meet the future needs of the State.

The problems here are inherent in the nature of the applications and the Natural Gas Act: if the Arctic gas proposal prevails, there is no physical means to move gas from North Slope areas to the State's population centers; the Arctic gas routing will simply preclude gas movement within the State since the gas will leave the State north of the Arctic Circle. If, on the other hand, the El Paso proposal prevails on the basis of present filings with the FPC, the full natural gas stream will begin movement in interstate commerce, and even though it may be physically possible to withdraw gas where and when needed in Alaska, it may be legally impermissible to do so.

4/ Whatever the transportation route, natural gas production and transportation may reasonably be expected to contribute significant revenues and economic activity to the State. Accordingly, even if the transportation system which is Federally authorized does not lend itself to serving state natural gas needs, benefits to the State still might result from natural gas production, and transportation. A decision in this regard involves a balancing of economic, environmental, and political considerations which are beyond the scope of the requested analysis, and outside the scope of my knowledge and experience.

The State's present danger stems from the fact that certificates may issue, and interstate service may commence, without formal recognition of the State's needs. Interstate service unconditioned to Alaska's rights, creates grave problems concerning later attempts by the State to withdraw gas from the system -- problems which arise under Granite City Steel Co., v. FPC, 320 F2d 711 (C. A. D. C.. 1963) which suggests that gas customers in Alaska may not be added as pipeline customers if the pipeline is, at the time service to new customers is sought, then unable to meet the needs of existing customers; under Sec. 7(b) of the Natural Gas Act as interpreted by the Commission, which suggests that a partial diversion of the interstate natural gas stream will not be permitted without prior Commission authorization; and under Louisiana Public Service Commission v. FPC, 359 F2 524 (C. A. 5, 1966) cert. den'd. 385 U.S. 833, which holds that commingling of non-jurisdictional natural gas with jurisdictional natural gas results in a single gas stream which is wholly jurisdictional.

It does not follow, however, that Alaska is powerless to influence the movement of North Slope gas in a manner more nearly suited to the State's future gas needs than the proposals now pending. To the contrary, I believe there are reasonable courses of action which the State can pursue.

The State may exercise the option set forth in its oil and gas leases to take royalty gas in kind, and market this production separately from working interest gas; the State need not seek FPC authorization for royalty sales, and should limit the term thereof to the extent possible.

I believe that it would be most unwise, under present circumstances, to permit the producing companies which hold leases on State lands to market the State's royalty share of gas production. If marketing occurs, with the gas moving in interstate commerce, the problems summarized above -- and particularly the Sec. 7(b) abandonment problem -- stand as very real threats to later withdrawal of State royalty gas from the marketing arrangements made by the producers. Most simply put, if 8/8ths of the gas stream is committed to interstate commerce by delivery under an unconditional producer certificate of public convenience and necessity, withdrawal of the royalty 1/8th at a later date may require

FPC approval -- which may, or may not, be forthcoming. This is the lesson of FPC Docket N. C171-879, Superior Oil Company, Letter Order issued June 13, 1975. (pp 64-73).

This particular problem can be mitigated if the State exercises its option, prior to the delivery of any gas, to take its royalty share in kind, with appropriate notice to producer, purchaser, and FPC that the producer is without authority to market the State's natural gas.

The State should, therefore, negotiate for separate sale of its royalty gas on the best terms available, giving due consideration to a relatively short-term sale. The State should take the position that it is not subject to the Natural Gas Act, nor to the jurisdiction of the FPC, and that the State is therefore free to make sales for resale in interstate commerce (or in any other market), without certificate authority, and without restriction as to rates or terms of service. This position, though clouded by the Court decision in FPC v. Corp. Comm. of Oklahoma, 362 F. Supp. 522 (W.D. Okla., 1973) aff'd 415 U.S. 961 (1974) is, I believe, legally sound and legally sustainable.

State marketing of its royalty gas is not a complete answer to the basic problem. That gas must be transported, and the only available means of transport will be through the facilities of an interstate pipeline. The FPC can, therefore, exercise indirect control of royalty gas through its certification powers under Section 7 of the Natural Gas Act, even to the extent of denying the right of transportation if it is opposed to the end-use to which the gas will be put, or the price paid for the gas. See FPC v. Transcontinental Gas Pipeline Corp., 365 U.S. 1 (1961), and pp.3-9 of the attached analysis. Thus, it will still be necessary for the State to involve itself in transportation negotiations and see that FPC approval of transportation arrangements is obtained, even if the State markets its own gas by sale at the wellhead or sale downstream. The protection which the State must have is advance FPC approval of State withdrawal of its gas from interstate commerce, but this approval should be sought and obtained by the transporter in connection with its certificate applications and related tarriff findings.

In suggesting these actions, I hold to the view that the State's power to call upon the gas resource when needed in the future can, in reasonable probability, be exercised if the State's rights and obligations are fully spelled out, fully presented to the FPC, and accepted by the FPC as an integral part of the transportation system which is certified by the FPC.

While all problems relating to future in-State use of State-owned gas may not be wholly solved by advance agreement, and advance FPC clearance, of specific production, transportation, and sales arrangements, it is my judgment that the problems are reduced to the levels of acceptable risk-taking if the FPC, prior to construction and operation of a transportation system, expressly conditions all necessary certificates of public convenience and necessity and pipeline tarrifs to permit and approve such arrangements as are negotiated by the State with respect to its royalty gas.

The State may consider the enactment of legislation to hold State owned resources within the State unless such are surplus to the needs of the state.

Discussed in some detail in the appended legal analysis is a recent Texas statute which is designed to secure for the benefit of the State the resources which are publicly owned. The statute is prospective in operation, and simply requires that all State-issued oil and gas leases shall contain appropriate provisions to prohibit sale of natural gas produced from State-owned lands outside the State unless it is found that such gas is surplus to the needs of the State. (pp. 79-85).

While the State clearly may not "embargo" natural gas through exericse of its regulatory powers, (pp. 43-45 it may be argued that the State's powers incident to ownership of public lands are different from, and greater than, mere regulatory powers. Cannot the State decide to withhold its lands from development? if so, (and about this I can see little argument), does not this right include the lesser right to permit development only upon terms acceptable to the State as a property owner? (pp. 15-17).

I do not offer an unqualified opinion that such legislation would withstand court challenge; I acknowledge that a challenge would probably be forthcoming, and that the legislation might fall as an undue burden on interstate commerce. Nonetheless, there is some chance of upholding protective legislation, and enactment could serve as a clear Legislative expression of Alaska's determination to retain a fair share of Alaska's resources. (pp. 79-85).

The State may consider various means of encouraging conversion of natural gas to methanol, or encouraging extraction of all natural gas liquids, prior to movement of natural gas in interstate commerce.

If North Slope gas is converted to methanol before becoming committed to interstate commerce, the conversion facilities, the methanol itself, and the transportation of methanol would not be subject to FPC control. Since the natural gas would be produced and "consumed" (i.e., converted to something other than natural gas) within the State, the natural gas would never become subject to FPC jurisdiction.

Similarly, if ethane, propane, butane, and other liquids are removed from the natural gas stream prior to transportation or sale in interstate commerce, the extraction facilities, the liquids themselves, and the transportation of the liquids should not be subject to FPC control.

It is beyond the scope of my knowledge to explore the economic feasibility of these alternatives; nor can I judge whether the oil pipeline now under construction can, from an engineering standpoint, serve as a conduit for methanol or other liquids. I believe, however, that the State should be aware that a natural gas stream has enormous potential value other than its obvious value as a heat source. It would be imprudent not to explore all potential uses of the gas stream; particularly where conversion within the State, or liquids extraction within the State, diminishes the range of FPC controls, and where, as here, the use of liquids for generation of heat represents a waste of valuable raw material.

Encouragement of conversion or extraction may be given through legitimate State tax incentives or through dedication, on favorable terms, of State-owned gas to a conversion or extraction project. The most effective means of encouragement should be determined at the time full exploration is made of economic and engineering feasibility.

Legislative action may be considered with respect to extraction operations, but probably may not be considered with respect to a conversion project. The latter situation would almost surely require an impermissable degree of interference with interstate commerce, since any statute directing the flow of natural gas to a con-

version plant would, in actual operation, preclude movement of gas in interstate commerce. Such a restriction would not, in my judgment, withstand Court challenge.

Legislative direction that liquids extraction occur prior to movement of the residue gas in interstate commerce may, on the other hand, be a valid exercise of State regulatory powers to prevent waste. This issue is discussed in some detail in the attached legal analysis (94-100), and I conclude that mandatory extraction, if based on appropriate finding that extraction is necessary to prevent waste of a natural resource, and if properly applied to preclude the possibility of an unconstitutional confiscation, has a reasonable basis and can, therefore, be defended.

In addition to the foregoing alternatives relating to possible State action to retain a portion of the State's gas resources for State use, other, and different, alternatives exist.

What Actions Can the State Pursue to Achieve Benefit from the State's Gas Resources?

Until this point, we have focused on natural gas transportation issues; I suggest that there are other matters which deserve consideration as the State of Alaska moves toward resolution of its basic energy policies. These other matters are not strictly within the request made of me for legal analysis, and indeed some require far more exhaustive consideration before a firm recommendation can be made; I touch upon each briefly because they are germane to the general issues under discussion, and because some, or all, may emerge as part of an overall State strategy of resource management.

1. State leasing policies should be re-examined.

   (a) The State is presently leasing on the basis of a one-eighth royalty. Other producing states, notably Texas and Louisiana, now demand, and receive, a one-fifth or one sixth royalty. Alaska should re-asses its bargaining position, its revenue needs, and whether the greater degree of control which in-kind royalty permits, justify leasing on terms other than those presently employed.

   (b) Consideration whould be given to the possibility that the leasing of State lands, or the withholding of state lands from leasing, is a valid instrument of State policy which can be used to assist in holding State resources for State needs; for example. can

leasing schedules be tied to changes in intrastate supply and demand? Can development be held until the State needs the resource? Here again revenue considerations and State desires regarding the optimum level of drilling and production activity must be weighed, but I suggest that one of Alaska's greatest strengths lies in its ownership of oil and gas bearing lands; thought should be given to the best use of that strength.

2. State taxing policies should be re-examined.

(a) The State presently provides for a production tax on natural gas of 4% of the gross value at the well; other producing states impose a much higher tax--for example, Texas exacts a severance tax of 7-1/2% of the market value of the gas when produced, and Louisiana imposes a basic severance tax of 7 cents/Mcf on natural gas. In considering whether revision of Alaska production taxes is appropriate, thought should be given to the Louisiana form: Louisiana's revenue levels are not controlled by the FPC, while Texas' are, at least to the extent that Texas gas is sold interstate. A further defect in the Texas structure lies in its requirement, in the final analysis, that Texas consumers bear a higher tax than out-of-state users; since the State tax is tied to value, intrastate sales at higher rates than interstate sales produce a higher tax bill for the intrastate producer than for the interstate producer.

(b) Alaska can consider the enactment of a franchise tax on interstate pipelines. Colonial Pipeline Company v. Traigle, 421 U.S. 100, decided April 28, 1975, upheld a Louisiana statute that imposed a franchise tax on a pipeline company that was admittedly engaged exclusively in interstate commerce.

In 1969, a Louisiana Court held that the commerce clause of the Federal Constitution was violated by a state tax "payable for the

privelege of carrying on or doing business... in this state." The Louisiana legislature then amended the offending provision by providing that the tax was levied upon "(t)he qualification to carry on or do business in this state in a corporate form". The Supreme Court of Louisiana upheld the tax as constitutional levy for priveleges enjoyed by corporations in the state carrying on business, interstate or local, in the corporate form. 289 So. 2d 93 (1974). The U.S. Supreme Court affirmed. The Court cited Memphis Natural Gas Company v. Stone, 335 U.S. 80 (1948), a case that sustained a similar franchise tax imposed by Mississippi on a foreign pipeline corporation exclusively engaged in interstate business. The Court quoted Justice Reed's opinion in the 1948 case: "This is a tax on activities for which the state, not the United States, gives protection and the state is entitled to compensation when its tax cannot be said to be an unreasonable burden or a toll on the inter-state business". The "activities for which the state gives protection" included "protection of... maintaining, keeping in repair, and otherwise manning the facilities of the system," the Court said.

Conclusion

As must be evident, it is my view that from the standpoint of legal consequence, the State should pursue an affirmative, aggressive course of enlightened self-interest if the present and future natural gas needs of the State are to be met. The State must decide what it wants, and then set out to achieve its goals.

My judgment is that the State may reasonably expect success in its negotiations. Consider the pressure points available to the State as bargaining levers:

1. Equity favors the State; it seeks nothing more than a share of the resources which it owns. Further, the State of Alaska alone bears a substantial environmental cost as North Slope resources are developed and transported; since this burden exists, an offsetting benefit should be made available to the people of Alaska.

2. The State has as-yet unused regulatory powers which can materially affect the flow of oil and gas.

3. The State has as-yet unused powers of ownership which can materially affect the flow of oil and gas.

4. The State has as-yet unused powers of taxation which can affect the price of oil and gas.

5. The State probably can retain some control of its royalty gas if the State takes effective action; by non-action the State stands to lose control of its royalty gas. The State's position on its royalty gas is of critical significance because it is doubtful that any North Slope transportation system can go forward without committment of royalty gas to the system, either as part of system supply or as the subject of a continuing transportation agreement. The transportation system needs the royalty gas volumes to support claims of economic viability.

These factors lead me to believe that the State can bargain effectively.

I believe negotiations with both transportation groups are in order. The Arctic Gas proposal has encountered significant opposition, and the FPC staff has only recently concluded that the Arctic Gas group should consider an alternative routing to bring its line down the Alyeska corridor to Fairbanks, and then south eastward. This routing offers an opportunity for physical movement of North Slope gas to, or near, population centers through an Arctic Gas line, a possibility which did not exist so long as Arctic Gas proposed to move eastward out of the State while still within the Arctic Circle.

El Paso should obviously also be approached in definitive negotiations. It has historically supported the principal that a portion of the Alaska gas should be made available for Alaska usage and the El Paso proposal can serve State needs with fewer major revisions than Arctic Gas.

It is, therefore, appropriate for the State to open negotiations with both transportation proponents. It is time to ask, and obtain, positive answers to one basic question: How can Alaska retain the benefit of its natural gas resource under your proposal?

What must be made clear is that the Alaska Legislature and the State Administration, have affirmative duties to ensure, to the fullest possible extent, that the needs of Alaska are served. Others may, and should, consider private interests. But it must be unmistakeably clear that Alaska will judge its present and future position on leasing, regulation, taxation, and royalty gas disposition with due regard to Alaska's present and future needs.

It seems to me that if Alaska can derive no benefit from natural gas produced within its borders in the sense of sharing in the use of the resource, then clearly Alaska can protect its citizen's rights only by looking to natural gas as a source of revenue. Every legitimate means of using gas to raise revenue should be explored. If, on the other hand, Alaska is permitted to share in the benefit of a secure and reliable source of natural gas for use as a non-polluting heat source and as a raw material feedstock, then Alaska need place less emphasis on direct revenue and more emphasis on cooperative development.

If men of good will make an intelligent effort at accommodation and understanding, there is no reason why the mutual problems of producer, transporter, and consumer cannot be solved in a manner which balances fairly their respective interests, and which also serves the interests of national and state government as well.

Respectfully submitted,

Rush Moody, Jr.

RM/ap

CITY OF VALDEZ

P. O. BOX 506
PHONE: (907) 835-4313

ZIP CODE: 99686

February 10, 1976

Senator John Rader, Chairman
Gas Pipeline Impact Committee
Pouch V
Juneau, Alaska 99801

Subject: Gas Pipeline Impact Committee Meeting, February 17,18, 19, 1976

Dear Senator Rader:

This is in reply to your letter of February 2, 1976 regarding possible consumption of natural gas in the city of Valdez.

If natural gas becomes available to the city of Valdez, a whole new era would be opened up. The natural gas would be utilized to heat homes, businesses, schools and hospitals, power electrical generation turbines, and for processing raw materials, minerals and other as yet unknown industries. The use of natural gas would replace the use of heating fuel for heating purposes, thus allowing the heating fuel to be utilized in other more economical ways.

While I have no idea as to the quantity of natural gas which would be consumed by a city of 10,000 to 15,000 people, I am certain it is considerable.

With the El Paso natural gas pipeline passing through the city of Valdez, it would be very inexpensive to construct a short service line into the city proper. The savings to the consumer would be fantastic just in transportation costs alone.

As soon as we become aware that the El Paso gas pipeline is to be built, the city administration of Valdez will immediately undertake the necessary steps to assure an adequate distribution system for the city.

The availability of natural gas to the citizens of this state is a vital necessity if the state is ever to become other than a consuming state. A low cost energy source is necessary if Alaska is ever going to be able to compete with other states in the production of consumer goods.

I urge you to exert every effort to assure that state royalty gas be retained for use within the state of Alaska.

Very truly yours,

Herbert W. Lehfeldt
City Manager

AGO 545844

HWL:ss

GOLDEN VALLEY ELECTRIC ASSOCIATION INC. Box 1249, Fairbanks, Alaska 99707, Phone 907-452-115

February 13, 1976

Senator John Rader, Chairman
Joint Gas Pipeline Impact Committee
Alaska State Legislature
Juneau, AK 99801

Dear Senator Rader

I recently read the Moody report and wholeheartedly concur with its recommendations.

There is a substantial potential market for natural gas available in Interior Alaska. GVEA will have 140,000 KW of base load type gas turbine capacity in operation by November 1977. These units, at nominal base load capacity would require approximately 25,000 cu. ft/day. Eight other reserve peaking units could be adapted to burn gas quite easily and would be if the economic anlaysis proved favorable. Our system plans to add an additional 100,000 KW of generation by 1980-81; therefore, by 1981 GVEA alone would be capable of using in the neighborhood of 50,000 cu. ft/day of natural gas. Other area steam/electric plants in combination would require about 30,000 cu. ft/day.

Further, I feel certain that Alyeska would consider burning natural gas at their pump stations 5 through 12 now scheduled to burn #2 distillate. These stations in combination phase 3 operation would use approximately 70,000 cu. ft/day.

Arrangements might be made to have them back off and go on liquid fuel as other industrial gas requirements and needs within the State developed.

It appears that this is one way that the State might initially utilize this valuable resource and more important, better guarantee its continued availability within the State of Alaska.

Best wishes.

Very truly yours

R. L. Hufman
General Manager

RLH:dee

AGO 545845

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

February 16, 1976

Senator John Rader, Chairman
Joint Gas Pipeline Impact Committee
The Legislature of the State of Alaska
Juneau, AK 99801

Dear Senator Rader:

At your invitation we have rescheduled our travel in order to be present at this hearing, together with our consultant, Mr. Charles E. Smith. Charlie was the Alaska manager for Union Oil Company of California from 1959 to 1962, and later was their vice president for natural gas and gas liquids. He is now president of Transworld Gas Systems Inc., of Whittier, California. He has broad and thorough knowledge of the natural gas industry and its problems and prospects, and has assisted in preparing our position today.

We believe that it is essential and even imperative that the State should resolve not to let the Prudhoe Bay royalty gas become committed to or sold in interstate commerce and thus become subject to federal jurisdiction. Our review of the "Legal Analyses of Issues Relating to Natural Gas Transmission" as submitted by Rush Moody, Jr., strengthens this belief.

Based on our present sales and historical growth rate, we may have less than 10 years' supply remaining in our present contract for gas from the Kenai Gas Field. We are doing whatever we can to supplement these supplies: from Cook Inlet Royalty Gas; by negotiations for additional gas from existing uncommitted reserves in the Cook Inlet area; and by our own exploration program in the Susitna Valley. However, there is competition for all such gas reserves, from Japan and

west coast cities, and it is apparent to us that existing Cook Inlet area gas sources will not be sufficient to supply all the existing demand for this gas. In fact, we can show that there is a projected deficit of about four (4) trillion cubic feet to the year 2000. This conclusion can be seen from the report (SRI Project ECC-4304) which Stanford Research Institute prepared in December 1975 for Pacific Alaska LNG Company. This deficit is approximately the same as the quantity of proven Prudhoe Bay royalty gas. In order to adequately protect the consumer, we do not believe it would be prudent for us, nor would it be in the public interest for the State, to rely on any but proven reserves as the future supply for use within Alaska. We do believe the State should view the Prudhoe Bay royalty as the best proven gas reserve for Alaskan use in future years, regardless of which route is selected for delivering this gas to market.

If the El Paso project is finally approved, which we favor, the alternatives open to the State are more straightforward. State gas can be removed from the pipeline prior to delivery to the LNG plant, and a pipeline connection can be made to the existing gas distribution system in Anchorage. In addition new distribution systems could be installed in any city within economic range of the line. Gas which is surplus to the needs of these distribution systems can be stored in underground reservoirs for future deliveries and peaking service, or converted to methanol fuel for distribution throughout Alaska, particularly as an alternative

fuel for power generation. In our opinion such a plan would exempt the gas from the jurisdiction of the Federal Power Commission.

In the event the Canadian routing were to be chosen for Prudhoe Bay gas, there are several possible alternatives to be considered for the treatment and transportation of the royalty gas:

(1) A small gas line might be laid to bring the gas to the vicinity of Fairbanks. After satisfying Fairbanks' needs, the remaining gas could be converted to methanol fuel or LNG for further delivery by appropriate means. Methanol fuel has equal or superior qualities as a fuel, and is also in demand as a petrochemical feedstock. Methanol fuel can be utilized as a liquid fuel replacing oil, with minimal equipment change out, but with combustion characteristics equivalent to natural gas. It would be an ideal peaking fuel for the gas turbines which supply power in Anchorage and Fairbanks. Thus even if the 7/8 of Prudhoe Bay gas is taken through Canada, the royalty could be used as fuel by many Alaskan communities and any excess could be sold in the world market. Methanol fuel could be transported by rail to Seward or Whittier for further delivery throughout Alaska. LNG might be exchanged with Pacific Alaska LNG Company for natural gas reserves in place in the Cook Inlet area.

(2) The Prudhoe Bay royalty gas could be converted to LNG or methanol fuel at wellhead and delivered by Boeing 747 cargo aircraft. Transworld Gas Systems has made studies in cooperation with Boeing which indicate that air movement of LNG is technically feasible for transportation from remote areas. Such a method adapts itself to small deliveries of gas into areas not yet being served. Further, LNG would be valuable as peaking fuel in the Anchorage area and it could provide base load fuel after the Cook Inlet reserves are depleted or otherwise committed.

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

The cost of detailed evaluation and engineering of these alternatives cannot be justified unless or until it is known that the Canadian route will be chosen, and in such event there should be adequate time for the State to provide for handling of royalty gas by the time actual gas deliveries begin. However, as a precautionary measure we believe the State should retain the option to keep the royalty gas in place whether prior to completing its delivery facilities or during any "downtime" of these facilities after deliveries have started.

Regardless of the gas line routing decision, Prudhoe Bay royalty gas is a vital resource for Alaska, and control of its use should be reserved to the State rather than federal authorities. We do not believe that the State should allow even temporary deliveries into interstate commerce because of the danger in relying on existing regulatory and judicial precedents. Only by retaining the gas in place or by taking it as it is produced can the State maximize its opportunity to retain control We urge the legislature to act now, before any commitment can be made or even presumed by federal authorities or by the applicant companies.

If adequate gas supplies should become available in the Cook Inlet area in the future and the Prudhoe Bay royalty thus becomes surplus, the State could at such time release it into interstate commerce.

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ANCHORAGE, ALASKA

The foregoing is the only direct testimony we have at present. We would request that response to any questions be extended to include our consultant, Mr. Charles Smith of Transworld Gas Systems and Mr. Harold Schmidt, who is our senior vice president, and Mr. Bill Hickman, who is our management analyst.

Very truly yours,

Dale Teel
President

DT:jdh



ALASKA PIPELINE COMPANY

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3000 SPENARD ROAD
PHONE (907) 277-5551

February 9, 1976

Senator John Rader, Chairman
Joint Gas Pipeline Impact Committee
The Legislature of the State of Alaska
Juneau, Alaska 99801

Dear John:

In 1975 our sales were about 30 billion cubic feet (BCF), to military and civilian power plants and to all other uses, residential and commercial. At the end of 1975 we had 450 BCF remaining under contract. Recovery of waste heat and other reductions of demand for gas by the power plants can be projected, and we are not obligated to the military after 1980. However, it may be prudent for us to anticipate that our annual sales will increase by 1 BCF or more each year for the foreseeable future. Thus we should be working to obtain additional reserves at every opportunity.

We have not been negotiating for Prudhoe Bay royalty gas thus far, because royalty gas is now available in the Cook Inlet area and because there may be about as much other uncommitted gas in the Cook Inlet area as there is of royalty gas at Prudhoe Bay. The distance (investment) and the daily volume required for using Prudhoe Bay royalty gas have made it comparatively impractical for us to consider thus far.

We have begun exploring for gas in the Susitna Valley in the hope that reserves for our requirements could be found and thereby avoid the full impact of competition by Los Angeles, Portland, or Tokyo for gas from the Cook Inlet area. However, we need gas (not just "hope") and if Prudhoe Bay royalty gas will be available within 5 to 10 years, we believe we should begin considering it as an alternative or supplementary supply. As I read the material you sent me, it seems to be essential that the Prudhoe Bay royalty gas should not be commingled with producer gas regardless of the route selected, in order for the State to retain control of its gas. This would mean that a separate pipeline would have to be built for this royalty gas.

If the State were willing to do the financing of such a pipeline, and compressors as necessary, it may be possible for us to arrange to take part or all of the Prudhoe Bay royalty gas. I believe that a 20 inch (?)

AGO 545851

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

pipeline, refrigerated to avoid permafrost problems, could be built along the oil pipeline right of way to the Fairbanks area and then along the new highway to the Anchorage area. It could serve the requirements of Chugach when their "Beluga" supply becomes inadequate, as well as our requirements particularly for the municipal and military power plants. It might also serve some of the requirements of present or future petrochemical industries. I am not sure what daily rate of royalty gas is being considered, but I assume it to be of the order of 100 to 200 million cubic feet per day, which compares to our present peak capacity of 160 million and our present average daily sales of about 75 million.

The seasonal aspect of our demand for gas may be the primary problem with our taking Prudhoe Bay royalty gas, but it may be possible to solve that problem by off-season industrial applications or other means. At any rate, we believe there may be sufficient prospect for Alaskan use of this gas that it should be fully explored.

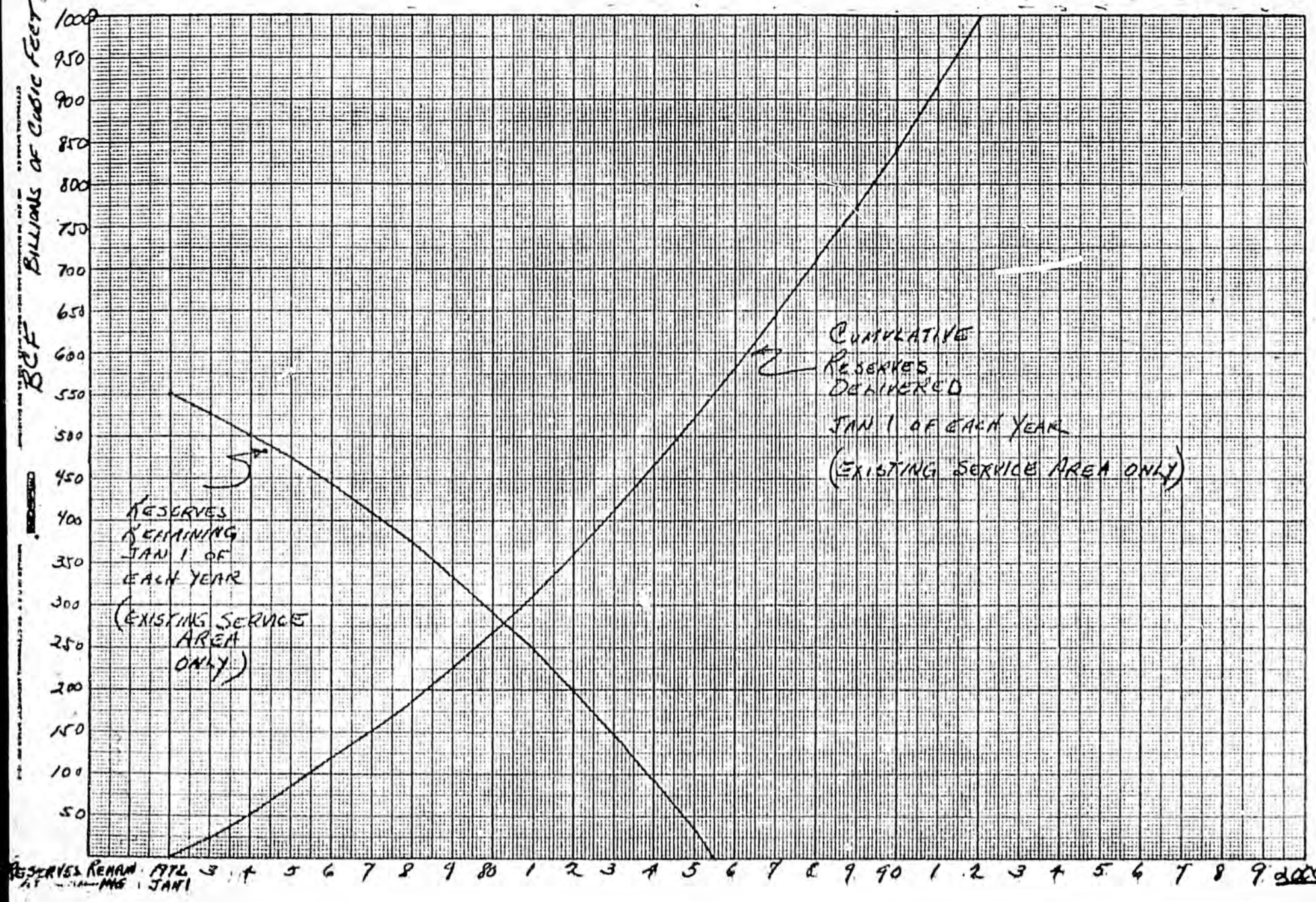
We are not prepared to testify on February 17-20, and will be out of the state on those days. However, we believe our position should be considered as your committee studies this subject.

Very truly yours,

Dale Teel

Dale Teel
President

DT:dh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AGO 545853

USE OF NATURAL GAS IN ALASKA

BY

GEORGE C. SILIDES, P. E.

TO THE

SPECIAL LEGISLATIVE COMITTEE ON

GAS PIPELINE IMPACT

FEBRUARY 17, 1976

AGO 545854

I N T R O D U C T I O N

For the record, my name is George Silides. I am a Registered Professional Engineer in private practice, a former State Senator, and a member of the Eighth Legislature's Interim Natural Gas Pipeline Committee

Thank you Senator Rader, and members of the Ninth Legislature's Special Committee on Gas Pipeline Impact, for your invitation to appear before you and express my thoughts on the complex issues confronting you.

The Committee of which I was a member made three recommendations to the Legislature.

1. That a Special Legislative Committee be established in order to continue studying the alternative proposals of gas pipeline construction and routings, and to keep abreast of the actions of the Federal Power Commission and the Congress.

2. Obtain legal expertise in the area of Federal Power Commission regulation in order to protect Alaska's interests.

The creation of this Committee before which I appear today, and the retention of Mr. Rush Moody, formerly with the F.P.C., bears witness that the first two recommendations were accepted.

3. The third recommendation was that the State take such action as appears necessary so as to make it's position crystal clear. I am proceeding under the assumption that this Committee intends to move in that direction. To this date no clearly stated intent as to the use of our royalty gas or oil has been announced, nor has the Commissioner of Natural Resources invited specific, bona-fide, binding proposals from interested persons for the purchase and use of our royalty gas or oil. There is a partial legislative remedy for this as I shall suggest later.

Senator Rader, who chairs this Committee, invited me to speak on the uses of Natural Gas. Most of my comments will deal, primarily, with this aspect, but I would be remiss in not exploring with you some of the other considerations that relate and govern our ability to secure the use of the gas.

Many of my comments appear similar to those of Mr. Rush Moody. I make no opologies for this since I, and others, have been making these comments to the Legislature since 1972. It is encouraging to be joined in them by someone of Mr. Moody's reputation, experience, and a Washington, D.C. address, who gives us a much clearer insight than before as to what we might expect from the Federal Power Commission.

AMOUNT OF GAS

Prudhoe Bay reportedly contains 26 trillion cubic feet of recoverable cap and solution gas. Each barrel of oil produced will bring up about 750 cubic feet of solution gas. Therefore, 9.6 billion barrels of oil production may be expected to result in the con current production of 7.2 trillion cubic feet of solution gas. In terms of daily production 1.2 million barrels of oil results in 900 million cubic feet of solution gas and 2.0 million barrels per day results in 1.5 billion cubic feet of solution gas daily. This, I stress, is exclusive of any allowable cap gas production.

At 12 1/2% royalty interest, Alaska's share of solution gas amounts to approximately 185 million cubic feet of solution gas daily. When cap gas recovery is allowed for full pipeline throughput, Alaska's royalty share will rise to about 310 million cubic feet daily under the El Paso proposal, and 435 million cubic feet daily under the Arctic Gas scheme. The question immediately arises as to whether or not a pipeline through Canada is detrimental to Alaska's internal economies by depleting our royalty share at a rate faster than we can consume or convert to the myriad of products capable of being produced from Natural Gas. Add to this the certainty that the price of Natural Gas at the market place will continue to rise in relation to the cost of production; should cause us to consider net income just as important as production of the oil reservoir in determining the allowable rate of production.

ALLOWABLE RATE OF PRODUCTION

This is not to suggest that we should curtail solution and cap gas production below that which is necessary to comply with sound reservoir engineering. Nor do I subscribe to the simplistic, out-of-context, interpretation from a recent report to support the theory that we would lose 4 1/2 per cent of recoverable oil reserves unless all gas production was witheld to the year 2000 or so. Mr. O. K. Gilbraith and Mr. Pat Dobey of the Division of Oil and Gas are the ones to question on that account.

I am assuming that for about the first two years of oil production we will allow removal of about one half the solution gas and none of cap gas until the true nature of the reservoir and its flow pressures can be accurately determined by the State's Engineers. I mention these figures as significant because in point blank questioning, officials of El Paso claimed that they would be willing to proceed with construction even at this early-on reduced flow, while the larger diameter-different system of the Canadian line apparently cannot afford such curtailment. In other words, we tend to further lose control unless an Alaska route is used.

USES OF NATURAL GAS

We come now to the various uses of Natural Gas. Let me say at the outset that the least efficient use one can make of gas is to burn it simply for heat or to generate power. Product manufacture is much more beneficial. Through such latter use we not only provide high quality employment but we actually preserve the resource by conversion to a usable product.

It is at this point that I feel compelled to digress into discussion of another route which my associates and I consider of greater benefit to Alaska for reasons that will become apparent.

Thus far you have had two proposals - one through Canada and one through Alaska to Gravina Point. That latter route touches only one urban area - Fairbanks.

Let me also suggest an alternative route to Cook Inlet - specifically the Beluga area. By so doing, the following benefits accrue:

1. The resource is made accessable to the majority of the people of the State, not just 15%.

2. One of the telling criticisms levelled against the El Paso scheme by Arctic Gas is the almost 8% of the gas to be consumed in the liquification process. At Beluga, coal can be used to power the liquification pumps, thus conserving a valuable resource and materially

assisting the creation of a coal mining industry.

3. Methanol manufacture from our royalty gas can be used for the export of coal in slurry form, capable of being transported by tankers. Heretofore, water was used to transport crushed coal in pipelines. Upon arrival at the boiler, about 90-95% of the water content had to be removed. Using a methanol carrier, the slurry can be fired directly into the using boilers.

This, of course, is burning up the resource, not the most efficient use. But, at least, it has assisted in the formation of jobs and taxable income.

Methanol is a liquid chemical commodity of many uses. One important use is the manufacture of formaldehyde, from which are made synthetic adhesives for use in plywood, particle boards and in compressed wood - a superior substitute for scarce hardwoods. It also leads into a long chain of melamine plastics whcih can easily be manufactured in Alaska for export.

Other salient characteristics of products capable of large scale manufacture of products in Alaska are:

Amonia, urea and nitrates, needed in increasing quantities to sustain the world food supply. Alaska should become a major exporter of fertilizer. These products can be traded for imports which we need.

Nor should the agrarian potential of Alaska be ignored. Cattle ranchers on Kodiak Island and Aleutian Islands have been inhibited by the high cost of feed. The Tanana Valley is producing grain at more than twice the national average per acre. The key to successful cattle and swine raising in Alaska is abundant, cheap fertilizer. Gas is the raw material.

A particularly pure iron can be smelted continuously in the electric furnace, using gas or synthesis gas in place of coke. The tetaniferous iron ores of Klukwan and Snettisham can be smelted by this process in a clean manner.

Going quickly through a partial list of possible uses in Alaska for very large amounts of gas we find the following:

Synthesis Gas
Amonia
Urea
Nitric Acid
Methanol
Formaldehyde
Lime
Pelletized Ore and Iron
Cement
Acetylene
Vinyl Chloride and Polyvinyl Chloride
Nitrates
Fertilizers
Plastics
Adhesives
Residue Board and Compressed Wood
Polypropylene, Polyethylene
Styrofoam
LNG

Also of importance is the availability of bottled gas to the smaller towns and villages which now suffer both high prices and fuel shortage problems. Obviously, these smaller communities cannot afford piped distribution systems.

We can see then, that gas derivitives such as ethane and propane can provide a substantial,, clean petrochemical industry in Alaska. Non-availability of feedstocks rather than cost retards petrochemical capacity. Investment is moving toward the oil and gas producing areas where feedstock availability can be assured. Examples are the Province of Alberta and British Columbia. Last year a 1.5 billion dollar ethane plant was announced in B.C.

CONTINGENCY PLAN

The question arises: "Can we have these things in the face of adverse ruling by the F.P.C., either in routing through Canada or attempted interference in our internal affairs." The answer is, "Yes, if we have a contingency plan."

First: Take the gas in hand. Make no committment of sale to either pipeline, but retain control from the well head to the market place. Declare this intent by final passage of SB 174 on oil and gas. That Bill was introduced by the Senate Resources Committee at my request in 1974. It passed the Senate 18-2 and now resides in the House Resources Committee. If the Administration cannot make up its mind on this matter the Legislature can do it for them.

Do not, as has been suggested, amend the provisions of the statute giving legislative overview of the decision of the Oil and Gas Advisory Board. This Bill was co-sponsored in 1974 by Senator Silides, Senator Butrovich, Senator Poland and Senator Croft. It has proven the corner-stone of public scrutiny by the Legislature.

Second: In either routing, and especially if the line goes through Canada, negotiate a trade for our share of the Methane in exchange for Gas Liquids. This trade should be on a BTU equivalent.

Methane constitutes about 68 1/2 per cent of the gas produced at Prudhoe. The availability of Methane within the State is not as important as the availability of gas liquids, relatively speaking. It is the Methane that the mid-West cities are seeking to introduce into their distributor systems. Alaskan cities, with the exception of Anchorage and Fairbanks, do not warrant such distributor systems.

Ethane, Propane and Butane are more important to the State.

A. Bottled gas for rural use is needed to enhance the quality of life throughout the State.

B. The gas liquids are the main feedstocks for petrochemicals.

C. The gas liquids appear not to be subject to F.P.C. regulations.

D. The volume of gas liquids thus obtained could make a small diameter, high pressure pipeline possible from Prudhoe Bay to Tidewater. It most certainly bears study by the Committee.

CONCLUSION

I could continue this complex discussion at even greater length, but I may have already exceeded my brief. My main purpose was first to indicate the value of the resource, and secondly, to suggest that avenues other than the very obvious remain open, and that they should be explored with a firm, positive action.

The ORGANIZATION for the MANAGEMENT of ALASKA'S RESOURCES, INC.

TESTIMONY PRESENTED BEFORE THE GAS LINE IMPACT COMMITTEE

FEBRUARY 17, 1976, JUNEAU, ALASKA

MY NAME IS BOB HARTIG, I SERVE AS ONE OF THE 49 FOUNDERS AND A MEMBER OF THE EXECUTIVE COMMITTEE FOR THE OMAR GROUP. WHILE OUR ORGANIZATION SEEKS TO PROMOTE THE WISE MANAGEMENT OF ALL ALASKA'S RESOURCES, FOR THE PAST 10 MONTHS, OMAR HAS BEEN DIRECTING ALL ITS EFFORTS TO ONE PROJECT--THE CONSTRUCTION OF A TRANS-ALASKAN, ALL AMERICAN NATURAL GAS PIPELINE RATHER THAN THE PROPOSED TRANS-CANADIAN LINE.

OMAR WELCOMES THE OPPORTUNITY TO SPEAK TO YOU AGAIN TODAY, AND COMMENDS YOU FOR YOUR CONTINUING INTEREST. WE ALSO WISH TO COMMEND THE COMMITTEE'S ACTION IN COMMISSIONING RUSH MOODY, JR. TO RESEARCH AND REPORT ON SOME OF THE MATTERS CONCERNING THE STATE'S RIGHT AND ABILITY TO CONTROL ITS NATURAL RESOURCES.

I DO NOT WISH TO RESPOND TO THE TECHNICAL QUESTIONS WHICH WERE POSED BY THIS COMMITTEE IN ITS CALL OF THIS HEARING BECAUSE OMAR IS NOT AN ENGINEERING FIRM. INSTEAD, WE ARE A GROUP OF CONCERNED CITIZENS AND, IT IS IN THE AREA OF PUBLIC POLICY THAT WE FUNCTION.

MOST IMPORTANT OF THE THREE POINTS WE WISH TO MAKE TODAY IS THAT WE ARE DETERMINED TO SEE THE GAS LINE BUILT THROUGH ALASKA. OUR REASONS ARE BOTH ECONOMIC AND ENVIRONMENTAL. IT MAKES SENSE TO USE THE CONTINUED DEVELOPMENT OF ALASKA'S RESOURCES TO KEEP UNEMPLOYMENT RELATIVELY LOW. IT MAKES SENSE TO KEEP OUR RELATIVELY PROSPEROUS ECONOMY AT THE CURRENT LEVEL. IT MAKES SENSE TO USE THE EXISTING ROADS, CONSTRUCTION CAMPS, LANDING STRIPS AND COMMUNICATIONS

FACILITIES AS MUCH AS POSSIBLE FOR A GAS LINE ONCE THE ALYESKA LINE CONSTRUCTION IS COMPLETED IN ORDER TO REDUCE ENVIRONMENTAL DAMAGE AND REDUCE LOADING COSTS.

IN ADDITION TO BEING VITALLY AFFECTED BY THE COSTS OF THE TRANSPORTATION SYSTEM FOR THE NATURAL GAS, ALASKANS ALSO DESERVE THE OPPORTUNITY TO USE THE ROYALTY SHARE OF THE GAS - 12½% - TO MAXIMIZE ECONOMIC BENEFITS TO THE ENTIRE STATE.

THEREFORE WE RECOMMEND THAT THE MEMBERS OF THIS COMMITTEE CONSIDER TAKING THE FOLLOWING ACTIONS:

1. REQUEST THAT THE ADMINISTRATION NOTIFY ALL HOLDERS OF THE PRUDHOE BAY OIL AND GAS LEASES THAT THE STATE ELECTS TO TAKE ITS ROYALTY GAS IN KIND.

2. TO INSURE CONSTRUCTION OF THE TRANS-ALASKA PIPELINE, CONSIDERATION SHOULD BE GIVEN TO THE PRESENT SALE OF THE ROYALTY GAS TO THE FIRM WHICH WILL BUILD SUCH A LINE. SUCH A COMMITMENT OF ROYALTY GAS TO A TRANS-ALASKA PIPELINE WILL SUBSTANTIALLY HELP BRING THAT LINE INTO BEING.

3. WHILE IT IS RECOGNIZED THAT MOST GAS SALES CONTRACTS ARE NORMALLY LONG TERM CONTRACTS, AN EFFORT SHOULD BE MADE TO OBTAIN A RELATIVELY SHORT TERM SALE. PROVISIONS SHOULD ALSO BE MADE IN THE ROYALTY GAS SALES CONTRACT TO WITHDRAW CERTAIN PERCENTAGES OF THE GAS THROUGHPUT TO PROVIDE FOR NEEDS OF COMMUNITIES ALONG THE PIPELINE ROUTE, INCLUDING THE FAIRBANKS AREA. WHILE THESE EXACT NEEDS MAY NOT BE DETERMINABLE, IT IS SUBMITTED THAT PROVISIONS WHICH WOULD PERMIT INCREASING PERCENTAGE WITHDRAWALS OVER THE PERIOD OF THE SALES CONTRACT WOULD MEET THE INCREASED DOMESTIC AND INDUSTRIAL DEVELOPMENT NEEDS AS THEY BECOME IDENTIFIABLE.

THE RECOMMENDATION TO SELL THE STATE'S ROYALTY GAS IS BASED ON THE RECOGNITION OF THE FOLLOWING:

1. ALASKA HAS NO IDENTIFIABLE USE FOR THE GAS.

2. AMOUNTS OF FLOW ARE STILL UNDECIDED WITH INITIAL FLOWS BEING DETERMINED BY THE ALASKA OIL AND GAS CONSERVATION COMMITTEE ON PROJECTIONS. THESE FLOWS WILL LATER BE ADJUSTED BASED ON EXPERIENCE OF PRODUCTION.

3. ONLY AFTER THE PRODUCTION SCHEDULE IS ESTABLISHED CAN A FIRM DETERMINATION BE MADE OF HOW TO BEST MEET THE NEEDS OF OUR COMMUNITIES, AND POSSIBLE PETROCHEMICAL DEVELOPMENT.

4. PETROCHEMICAL DEVELOPMENT NORMALLY REQUIRES LEAD TIMES OF BETWEEN 5 AND 10 YEARS.

5. FUTURE DISCOVERIES WILL BE AVAILABLE TO MEET FUTURE NEEDS.

WE FEEL THIS PROGRAM RECOGNIZES THE NECESSITY OF HAVING THE STATE'S ROYALTY GAS AVAILABLE FOR USE WITHIN THE STATE AND THE IMPORTANCE OF UTILIZING THE AVAILABILITY OF THE STATE'S ROYALTY GAS AS A WEAPON IN GETTING THE PIPELINE BUILT THROUGH ALASKA.

AS TO THE SPECIFIC QUESTIONS POSED BY YOUR COMMITTEE IN YOUR LETTER OF JANUARY 30, 1976:

(1) (a) WE ARE IN AGREEMENT WITH MR. MOODY'S LEGAL ANALYSIS. PRELIMINARY RESEARCH CONDUCTED BY OMAR PERSONNEL TOGETHER WITH INFORMATION GAINED IN MEETINGS WITH OUR CONGRESSIONAL STAFFS AND PERSONNEL WHO POSSESS AN EXPERTISE IN FPC MATTERS, HAS ALREADY CONVINCED US OF THE NEED TO ESTABLISH A NATURAL GAS POLICY FOR THE STATE AND THE IMPORTANCE OF AND THE ACCURACY CONTAINED IN MR. MOODY'S LEGAL ANALYSIS.

(b) MOST OF MY STATEMENT HAS BEEN DIRECTED TO ANSWERING THIS. HOWEVER, WE WOULD URGE THAT STATE LEGISLATION ALTER TAXATION AND LEASING STATUTES TO PROVIDE INCENTIVES TO THOSE PRODUCERS WHO UTILIZE THESE RESOURCES

WITHIN THE STATE.

(2) RESERVOIR RECOVERY IS BEYOND OUR PROVINCE. HOWEVER WE WOULD EMPHASIZE THE QUALIFICATIONS PLACED ON THE STUDY BY THE CONTRACTOR AND THE STATE. THAT IS, THAT "RESERVOIR PERFORMANCE PREDICTIONS ON A FIELD WITHOUT PRODUCTION HISTORY ARE APPROXIMATE AT BEST". AND IN ADDITION, WE WISH TO CALL ATTENTION TO THE FACT THAT ARCTIC GAS HAD RECOVERY PROJECTIONS SIMILAR TO THE STATE, YET ACCORDING TO A NEWS REPORT FROM THE OTTAWA JOURNAL, THE CONSORTIUM STILL INTENDS TO BUILD A PIPELINE SYSTEM LARGER THAN NEEDED, IN EXPECTATION OF TRANSPORTING FUTURE GAS FINDS THROUGH THAT SAME LINE. THIS MEANS THE INITIAL TRANSPORTATION COST WOULD BE HIGHER THAN NECESSARY, AND THE RESULTANT RETURN TO THE STATE OF ALASKA LOWER THAN IT SHOULD BE.

(3) REGARDING PROSPECTIVE PURCHASERS FOR THE ROYALTY GAS, AND USES WITHIN THE STATE, WE FEEL CONFIDENT THAT ONCE A GIVEN QUANTITY OF GAS AND DATE OF AVAILABILITY IS DETERMINED, THERE WILL BE NO LACK OF PURCHASERS FOR PETROCHEMICAL USE. BUT ALL OF THAT IS MOOT IF WE DO NOT DEAL WITH THE GAS AS A WEAPON IN GETTING THE GAS LINE BUILT THROUGH OUR STATE.

IN SUMMARY:

(1) ONLY WITH A TRANS-ALASKAN NATURAL GAS PIPELINE WILL THE STATE BE ASSURED OF THE OPPORTUNITY TO RETAIN ITS ROYALTY SHARE FOR FUTURE DOMESTIC AND INDUSTRIAL USES.

(2) IN ORDER TO ENSURE THE APPROVAL AND CONSTRUCTION OF A TRANS-ALASKAN PIPELINE THE DISPOSITION OF THE STATE'S ROYALTY GAS SHOULD BE USED AS A WEAPON. IN THAT REGARD, AND, RECOGNIZING THAT THERE IS PROBABLY NOT A PRESENT IDENTIFIABLE NEED FOR THE GAS, THE STATE SHOULD : (1) NOTIFY ITS OIL AND GAS LESSEES OF ITS PRESENT ELECTION TO TAKE ITS ROYALTY SHARE IN

KIND (2) ARRANGE FOR SHORT TERM SALES OF THE ROYALTY GAS IF POSSIBLE OR IN THE ALTERNATIVE, LONG TERM SALES WITH PROVISIONS TO ACQUIRE INCREASE PERCENTAGES ON A FIXED SCHEDULE.

IN ADDITION:

(3) THE LEGISLATURE SHOULD CONSIDER LEGISLATION WHICH WOULD ALTER FUTURE LEASES FOR OIL AND GAS TO PROVIDE INCENTIVES FOR UTILIZING THESE RESOURCES WITHIN THE STATE.

BP Alaska Inc. 100 Pine Street, San Francisco, California 94111. Telephone (415) 445-9400

February 17, 1976

Senator John Rader
Chairman, Joint Gas Pipeline Impact
Committee
The Legislature Of The State Of Alaska
Juneau, Alaska 99801

Dear Senator Rader:

We appreciate having an opportunity to submit our comments on your letter of January 30, 1976, soliciting testimony on the Rush Moody Report, the State's Reservoir Analysis and Royalty Gas Options. We will also respond herein to your letter of January 15, 1976, asking five questions regarding the recently published Department of Natural Resources Study on Sadlerochit Reservoir Conservation.

At the outset, there are a few things that should be said about the position of BP Alaska in these matters. By means of its 1969 agreement with Standard Oil Company (Sohio) BP Alaska conveyed its working interests in the oil and gas leases in the Prudhoe Bay area to Sohio reserving to BP Alaska a seventy-five percent net profits royalty interest from production from the Prudhoe Bay properties attributable to production in excess of a certain level. The effect of this agreement is to make Sohio the working interest owner of all the gas under the Sohio/BP leases in Prudhoe Bay. The same agreement made BP Alaska the operator of the Sohio interests in Prudhoe Bay.

The BP Alaska net profits royalty interest does not come into play until production of oil reaches levels in excess of approximately 1,200,000 barrels per day. It will be recalled that this is the level of production which the Trans Alaska Oil Pipeline will be capable of handling under current authorization.

Since the BP Alaska net profits royalty interest in gas is triggered by certain criteria of sustained oil production of specified volume and at specified times, it will be seen that the BP gas interest is of small magnitude in comparison with the interests of the principal gas working owners in the Prudhoe Bay Field which are ARCO, EXXON and SOHIO.

BP Alaska has entered into an agreement with Northern Natural Gas Company giving that company the option to purchase the as yet undefined volumes of gas that may be attributed to BP Alaska through BP Alaska's net profits interest agreement up to a maximum volume of three trillion cubic feet. It should be noted that the Northern Natural Gas agreement covers not only gas from Prudhoe Bay but also any other gas which is attributable to BP Alaska and which may be produced from other North Slope oil and gas leases owned by Sohio and BP.

BP has further agreed with Columbia Gas Transmission Corporation to make available to that company any BP gas which is not required to satisfy its undertaking with Northern Natural Gas.

BP Alaska has not entered into any agreements which concern the basis or method of transport of the gas which the above two companies have the option to purchase or in respect to any other gas that may be available to our company on the North Slope. BP Alaska has no intention of participating in the construction of a gas line nor of assisting in the financing of such a venture. BP Alaska is not aligned with the proponents of either of the two principal schemes for transportation of Prudhoe Bay gas. Our role is simply that of a producer of gas.

The Moody opinion represents a very substantial exercise in legal scholarship involving a number of complex legal issues. As the author concedes, it also raises issues which involve rather longer term implications than the immediate question of the State's disposition of royalty gas and the alignment of the gas pipeline.

We can not responsibly endorse or reject an effort of this magnitude without comparable research and analysis. We understand the State's concern with its ability to control the disposition of its royalty gas in the light of Federal law and regulation. We believe the Moody Report is correct in its conclusion that the State should decide as quickly as possible the ultimate goals of the State's natural gas policy. If the State determines that it is in its best interest to attempt toretain a portion of Alaska's gas for future Alaskan needs, we agree with Mr. Moody's recommendation that positive action must be taken before the gas has been committed to interstate commerce. Such participation could include, as Mr. Moody suggests, active involvement by the State in transportation negotiations with the Federal Power Commission.

With respect to the possible changes in the State's leasing and taxing policies, discussed by Mr. Moody, the discussion centered as much on questions of policy as on legal issues. In view of the complexity of the policy and legal issues which might be presented by novel taxation proposals and suggested changes in the State's leasing laws and regulations, we propose to defer comment until the committees of the legislature meet to consider specific proposals incorporating such changes.

We now turn to your letter of January 15, 1976, which poses questions arising out of the State's recent study on the Sadlerochit Reservoir. For ease of reference we set out below the questions and our answers.

1. What effect does the recent study, "Prediction of Reservoir Fluid Recovery Sadlerochit Formation Prudhoe Bay Field", have on marketing plans for Prudhoe Bay gas?

   The State study evaluated several possible reservoir management schemes and indicated the relative effect of each hypothetical case. The results are not inconsistent with our anticipation that a practical reservoir management scheme can be implemented that will allow gas offtake from the field at rates of the order of 2 bscf/d sales.

2. How does this study differ from industry and federal studies?

   Published studies have predicted various production characteristics, consistent with the available detail and reliability of the data applied. It is to be expected that slightly differing results will be found in these circumstances, but generally the same relative effects of reservoir management schemes are to be found.

3. How accurate can a model be without production history?

   Model studies incorporate many uncertainties with or without any production history. They are certainly more reliable when production history is available for calibrating the various input parameters. They can be considered to be reliable as to general performance and are specifically valuable in assessing relative effects due to varying reservoir production schemes. Good reservoir management planning recognizes and allows for these uncertainties.

4. Will some production history be necessary before an accurate model is established that will prove feasibility of a gas pipeline for marketing of Sadlerochit gas?

   We believe it is possible to plan now for a reasonable level of gas offtake from the field, recognizing that the actual circumstance that results during production may need some modification to the reservoir management, particularly with regard to pressure maintenance, to continue to effectively produce the field.

5. How critical are the results of this study in obtaining FPC certification and financing for the gas pipeline project?

5. The above remarks indicate that we believe it is feasible, under a satisfactory reservoir management scheme, to plan for sustained gas sales. As a potential producer, it is not our principal expertise to comment on the gas marketing or financing questions. These could be more authoritatively answered by the gas pipeline/ marketing companies.

In conclusion, we do not believe that the recently published State of Alaska Department of Natural Resources Study nor the lack of production history should adversely affect the F.P.C. decision on the certification of a pipeline.

BP Alaska did not participate in the F.P.C. proceedings and has not been asked to respond to the interrogatories set out in the F.P.C. letter dated December 12, 1975. We have, however, testified at the hearings of your committee held on December 10, 1975, in Anchorage and at that time responded to some of the same questions included in the F.P.C. interrogatories.

It may be useful for you to be aware of answers we shall be providing to questions posed by the Senate Interior and Insular Affairs Committee and the Senate Commerce Committee under cover of a letter dated January 27, 1976, from Senators Warren G. Magnuson and Henry M. Jackson. A copy of the above letter and the referenced questions are enclosed for your convenient reference together with a draft of BP Alaska's response to those questions. The BP response is in the form of an internal memorandum dated February 12, 1976, to J. Gore of BP Alaska's Washington, D.C. office from D. B. Walker who is Vice President, Production Planning for BP Alaska.

If the Committee should desire further information on these or other matters during our new deliberations we will make every effort to respond.

Sincerely,

K. R. Keep

K. R. Keep
Vice President and General Manager

Enclosure

United States Senate

WASHINGTON, D.C. 20510

January 27, 1976

Mr. John Gore
Manager, Government Affairs
B. P. North America, Inc.
1730 M Street, N.W.
Washington, D.C. 20036

Dear Mr. Gore:

The Senate Interior and Insular Affairs Committee and the Senate Commerce Committee are examining the extent of Arctic natural gas reserves and alternative transportation systems for delivery of this gas to markets in the lower 48 states. The Committees are also examining the institutional, resource and other factors which may constrain or significantly influence the cost of this natural gas and the timing and mode of its delivery into the existing distribution system.

To facilitate our respective Committees' consideration of this matter and to develop the factual background relevant to major policy decisions respecting the development of Alaskan natural gas, our Committees request that you respond to the issues raised in the attached questionnaire by Parts I.A.; I.B.(1), (2), (3) and (6); II.A.(3), (a) and (b); and II.B. (2), (a), (b), (c) and (d). We would appreciate delivery of five copies of your response to these questions to the Interior and Commerce Committees no later than February 11, 1976.

For further information, please contact Henry Lippek at 224-9351 or Thomas Platt at 224-0611.

Sincerely yours,

Warren G. Magnuson

WARREN G. MAGNUSON, Chairman
Committee on Commerce

HENRY M. JACKSON, Chairman
Committee on Interior and
Insular Affairs

AGO 545875

94th Congress
2d Session

COMMITTEE PRINT

ISSUES CONCERNING THE TRANSPORTATION OF ALASKAN NATURAL GAS

QUESTIONNAIRE

PREPARED FOR THE

COMMITTEES ON INTERIOR AND INSULAR AFFAIRS

AND

COMMERCE

UNITED STATES SENATE



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AGO 545877

MEMORANDUM OF THE CHAIRMEN

In February 1976, the Senate Committee on Interior and Insular Affairs and the Senate Committee on Commerce will conduct joint oversight hearings on Arctic natural gas reserves and alternative transportation systems for delivery of this gas to markets in the lower 48 states. The Committees will examine the institutional, resource and other factors which may constrain or significantly influence the cost, timing and mode of delivery of this natural gas into existing distribution systems.

To facilitate our respective Committee's consideration of this matter and to develop a factual background on the major policy decisions respecting Alaska gas, interested persons are invited to respond to all or any of the attached questions by February 11, 1976.

Materials submitted will be included in the hearing record on this matter.

HENRY M. JACKSON,
Chairman, Committee on Interior and Insular Affairs.
WARREN G. MAGNUSON,
Chairman, Committee on Commerce.

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AGO 545878

I. ASSESSMENT OF NATURAL GAS SUPPLIES

A. Natural Gas Supplies

(1) What are the current estimates of proven reserves in:
(a) the Sadlerochit formation of the Prudhoe Bay field,
(b) other formations in the Prudhoe Bay field,
(c) reserves elsewhere in Arctic or Interior Alaska, or on the Arctic OCS, and
(d) the Mackenzie Delta and adjacent Canadian onshore and offshore areas.

(2) What additional reserves can reasonably be expected to be discovered and produced from each of these areas by 1985?

(3) What is the range of uncertainty and/or dispute in each of the estimates in questions 1 and 2 above:
(a) resulting from geological or engineering uncertainty,
(b) depending on leasing or resource development policies, or
(c) resulting from uncertainty about other factors (economic incentives, industry response, logistical problems, etc.)?

(4) What are the potential natural gas resources in each of the areas identified in question (1) and the likelihood of their producibility in volumes which could influence the viability or relative merits of alternative systems for delivery of Prudhoe Bay natural gas?

(5) Consider specifically what leasing or development policy regarding the Alaska outer continental shelf, Naval Petroleum Reserve No. 4, the Arctic Wildlife Range, state lands and lands controlled by Alaska Native corporations might be necessary to make viable various alternative transportation systems? Consider also the possibility of major discoveries in Lower Cook Inlet, the Gulf of Alaska, or other areas of Alaska, and their implications for the viability or merits of alternative transport systems?

B. Deliverability and Cost

(1) What levels of natural gas production could each of the areas considered in subpart A above reasonably be expected to support in each year 1980 through 1985, if transportation were available, given due allowance for the time necessary for field development?

(2) What is the range of uncertainty or dispute over each of these estimates? Consider particularly the relationship between crude oil recovery and natural gas production from the Prudhoe Bay field.

(3) The Van Poollen study for the State of Alaska implies that the potential tradeoff between gas and oil production from the Sadlerochit formation will not be known until

(a) tests have been made of the ability to inject water into the reservoir and a source of water has been assured, and

(b) the operation of the aquifer underlying the reservoir has been observed during oil production.

Is this inference correct? If not, can the optimum rate of gas production presently be calculated? If so, what is it? If the inference is correct, when are the earliest and latest dates that enough information might be available to make a prudent decision on the rate of gas production and the system to transport such natural gas

(4) (a) What is the statutory mandate and policy of the oil and gas conservation authority in Alaska with respect to optimizing the joint production of oil and gas?

(b) To what extent is there a requirement or authority for the agency or the State to consider economic or development factors (as opposed to physical conservation alone) in regulating field production levels?

(5) (a) Could the rates of production at Prudhoe Bay now contemplated by the applicants in Docket CP–75–96 before the Federal Power Commission be appreciably reduced by actions of the State of Alaska?

(b) When will the Alaskan conservation agency decide on the allowable rate of natural gas and oil production?

(c) Can its initial decision be later modified?

(d) Is there a conflict between the FPC's certificating authority and the State's conservation authority? If so, which authority would prevail?

(6) What is the anticipated cost (not necessarily equal to price) of Prudhoe Bay natural gas at the wellhead? Please supply the assumptions and detailed back-up for such estimates. Specifically:

(a) Are these calculations incremental costs, assuming that all joint costs of lease acquisition and field development are borne by oil production, or do they assume an allocation of such joint costs to gas production; and

(b) Does the cost estimate include the value of oil production forgone, if any?

AGO 545819

II. DEMAND FOR ALASKAN NATURAL GAS

A. Anticipated Shortages

In the absence of the Alaskan gas, what are the anticipated natural gas shortages in the lower 48 states by region in the 1980–85 period?

(1) Which pipelines are expected to be in deepest curtailment of priority users in that period? What is the range of uncertainty associated with these estimates?

(2) What is the anticipated intrastate demand for natural gas in Alaska during the 1980–85 period?

(a) How much of the Prudhoe Bay gas is planned to be consumed in Alaska?

(b) To what extent do these projections of Alaskan consumption assume natural gas use for boiler fuel and other uses for which oil or coal could be substituted?

(c) How much do these estimates vary with different assumptions concerning natural gas and oil prices?

(3) Which pipelines or distributors have options to purchase Alaskan natural gas at this time?

(a) Would the same piplines and distributors obtain Alaskan natural gas regardless of whether the Arctic Gas or the El Paso project are approved?

(b) What are the terms and conditions of these options to purchase?

(c) If Prudhoe Bay gas were to be sold to the pipeline systems in greatest need on the basis of the best current projections pursuant to the FPC's current curtailment policy, which pipelines would receive the gas and what quantity would be sold to each?

(d) On what terms would non-transportation system owners have access to the Alaskan gas transportation system?

(4) The State of Alaska has not yet committed its royalty share of the Prudhoe Bay gas to sale or options. Will the State's decision regarding disposition of its royalty gas (a), between interstate and intrastate purchasers, or (b) among interstate purchasers, significantly influence the viability or the FPC's evaluation of alternative transportation systems?

B. Price

(1) Is the demand for Alaskan natural gas sensitive to natural gas prices and to the price of alternative fuels in the lower 48 states?

(2) When do the producers and purchasers intend to enter into firm long-term contracts for the sale of the Prudhoe Bay natural gas?

(a) What is the reason for the delay to date?

(b) What price will the producers receive in the absence of FPC price controls?

(c) What will be the duration of the sales price?

(d) What are the other likely major terms of such contracts?

(3) For the two transportation systems proposed by the applicants and the modifications recommended by the FPC environmental staff, what are the anticipated:

(a) capital costs (in 1975 dollars);

(b) the initial total transportation tariff per Mcf delivered to points on the West Coast, in the Midwest and in the East; and

(c) the total transportation tariff per Mcf delivered to such destinations 15 years after initial delivery?

(4) Are current estimates realistic in light of the large cost overruns that recently have characterized major construction projects like the TransAlaksa oil pipeline, the Washington Metro or nuclear generating plants? To what extent do the current cost estimates take into account the likelihood of materials shortages, failure to perform by certain contractors, defects or late delivery of equipment, labor disputes, unusually severe weather, regulatory delays, etc.? If the experience of the Alaskan oil pipeline and all these factors are taken into consideration, what is the magnitude of total system costs (in both current dollars and 1975 constant dollars) that conceivably could be expected?

(5) To what extent does transportation at each system's design capacity depend upon additional discoveries of new reserves? What is the range of anticipated total capital and operating costs per Mcf at various levels of throughput?

6. (a) What is the size of the market for Alaskan gas in the lower 48 states if its average lower 48 city gate price (in constant 1975 dollars) is $2.00 per Mcf? $2.50 per Mcf? $3.00 per Mcf? $4.00 per Mcf? $5.00 per Mcf? What is the assumed oil price in these estimates?

(b) At each average price what portion of the total gas over the course of a year would be consumed by priority users, (residential and commercial) and at what price; and what portion would have to be sold for boiler fuel or as interruptible supply, and at what price?

(7) What would be the impact on demand for Alaskan gas if its price at the city gate were substantially higher than the equivalent average price of oil? At what price per Mcf would pipelines no longer be willing to purchase Alaskan gas? What is the probability and under what circumstances, taking into account production costs, all tariffs

and taxes, that the price of Alaskan gas would exceed the amount purchasers are willing to pay for an equivalent volume of base load supply?

Please provide the estimates requested in questions (6) and (7) on the alternative assumptions that Alaska natural gas is required to be priced (1) incrementally or (2) on a "rolled in" basis.

C. Cost of Delay

(1) What revisions must be made in project costs for each year of delay (up to five years) in the commencement of construction?

(2) What is the best estimate of the total cost to consumers for each year of delay beyond 1980 in terms of the price of alternative fuels or impact on the economy of a gas shortage?

III. STATUS OF REGULATORY APPROVALS

A. Agencies Involved

List all of the Federal and state agencies which must issue permits or approvals as a prerequisite to the construction or operation of an Alaskan gas transmission system.

(1) State the estimated timetable for the applicants to obtain such approvals in the absence of expediting legislation.

(2) Is it possible or reasonable for the FPC to grant a certificate for any gas transportation system before the deliverability issues identified in subpart I, B are resolved?

(3) State any approvals required after the FPC issues a certificate of public convenience and necessity. Can the necessity of any such approvals delay or even prohibit construction of the system?

(4) Identify the possibilities for slippage and delay in the timetable for the FPC and other agency approvals?

B. Federal-State Relations

(1) Are Federal and state approval processes coordinated?

(2) Is there a potential for conflict between state land-use, coastal zone management, construction, conservation, safety and other regulatory or taxation activities and Federal requirements and permits?

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(3) What is the mechanism, or what mechanism should be established, for encouraging early state input and resolving differences between Federal and state policies?

C. Judicial Review

(1) Which Federal or state agency decisions regarding the transportation of Alaskan gas are the likely subjects of judicial review? What is a reasonable estimate of the time required to complete such judicial review of agency decisions? Could construction commence while such judicial review was underway?

(2) In the absence of any legislation, what is the expected date on which construction could commence? Be completed?

D. Alternatives

Please provide estimates of the costs, environmental impacts, construction lead times and other relevant facts concerning:

(1) An alternative pipeline route from the North Slope to Fairbanks and then paralleling the Alcan Highway;

(2) Conversion of natural gas to methanol and shipment by the trans-Alaska oil pipeline or tanker or submarine; and

(3) Other possible alternatives.

E. Safety

What are the design and operation techniques to assure safe and continuous operation of Alaskan natural gas transportation systems?

1. What is the relationship between the Federal Power Commission and the Department of Transportation with respect to safety standards during gas pipeline construction and operation?

2. What are the probable and worst case estimates of injury and damage of natural gas pipeline accidents?

3. Which State and/or Federal agencies have jurisdiction over LNG terminal si[illegible] with respect to safety, distance from population centers, and ship traffic control?

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4. What plans or procedures have the responsible agencies or the applicant devised to prevent or deal with LNG tanker collisions or other LNG handling accidents? What is the best available technology to minimize the risk of an LNG accident and to deal with serious LNG accidents?

5. What are the probable and worst case estimates of injury and damage that could result from an LNG tanker or terminal accident? What are the owners' liabilities for such an accident? Are existing liability laws adequate to provide compensation for all damages resulting from a probable and worst case accident?

F. Canadian Procedure

(1) What is the status of Canadian proceedings regarding the Arctic Gas and Maple Leaf projects? What is the anticipated schedule for final approvals by the National Energy Board and the Cabinet? What approvals are required by Provincial Governments? Are there other opportunities for delay of a Canadian decision, such as settlement of Canadian native claims? What is the best estimate of when the Canadian Government will reveal whether a trans-Canada route to transport Alaskan gas is acceptable to Canada?

(2) To what extent does the Canadian decision in fact await or depend upon a decision by the United States?

(3) What diplomatic channels or other mechanisms are available to assure coordination of the U.S. and Canadian approval processes? How would differences be resolved if incompatible trans-Canada routes are approved in the U.S. and Canada?

G. Treaty Status

(1) What is the anticipated initialling date for the U.S.-Canadian pipeline treaty?

(2) What are the terms of the draft treaty?

(3) Would the treaty limit or restrain the taxation or regulatory authority of state or Provincial governments?

(4) What other issues remain to be resolved in a specific protocol dealing with an Alaska-Canada transmission system?

IV. FINANCING

A. Private Capability

(1) Do private capital markets have the capability to provide the necessary funds for the construction of an Alaskan gas transportation system? Can the equity capital for this project be attracted solely on the basis of regulated revenues from natural gas consumers? What is the anticipated interest rate at which needed long-term debt capital can be raised?

(2) Assume the project encountered substantial cost overruns. Could it still be financed privately? What are the outer limits of the amount of capital that could be privately raised?

B. Subsidies

(1) To what extent are either of the applicants intending to seek Federal subsidies, loan guarantees or other forms of financial assistance to offset costs or provide cost overrun protection?

(2) Can either project be constructed and operated without any such Federal assistance?

(3) If Federal assistance to protect against cost overruns is required, what incentives can be incorporated to give the successful applicant incentives to minimize costs?

(4) If a project requiring LNG transportation is certified:
(a) How many vessels would be needed?
(b) Where would such vessels be constructed?
(c) What is the amount of subsidies or loan guarantees likely to be requested?

C. Tariffs

(1) Is it anticipated that Alaskan gas will be sold pursuant to an all-events full cost of service tariff whereby rates are automatically adjusted to reflect any costs incurred and are paid by purchasers whether natural gas is delivered or not?

(2) What is the anticipated risk that gas deliveries will be interrupted over the life of a project?

(3) Is the private financing of the Alaskan gas transportation system contingent upon state and Federal approval of such an all-events tariff?

(4) Are there precedents for an all-events tariff in other situations?

(5) What is the likelihood that state public utility commissions would approve natural gas purchases conditioned upon such tariffs?

(6) Can purchasers obtain insurance from private markets to insulate them against financial difficulties if gas deliveries are interrupted?

(7) If the risk of interruption is significant, would it be prudent to limit the percentage of Alaskan gas entering any pipeline or distribution company?

V. LEGISLATION

(1) What legislation, if any, is required to facilitate the construction of an Alaskan natural gas transportation system?

(2) What subjects should such legislation address? Consider and comment on such matters as:
(a) an expedited schedule for FPC action;
(b) a narrowing of judicial review in time and scope;
(c) establishment of a Congressional review process;
(d) congressional selection of one or more routes by directing all involved federal agencies to expeditiously grant all required permits and licenses;
(e) establishment of wellhead price ceilings and tariffs for Alaskan gas;
(f) establishment of a consolidated administrative process for the siting of LNG facilities;
(g) basis for and extent of an LNG vessel owner's liability for damages in the event of accident;
(h) provision for financial assistance to assure project construction;
(i) providing for allocation of Alaskan gas to pipeline systems in greatest need;
(j) resolution of environmental issues associated with the transportation of Alaskan gas; and
(k) other matters.

○

09
AGO 545882

February 12, 1976

TO: J. Gore - Washington, D.C.

FROM: D. B. Walker - San Francisco, CA

Response to questions regarding "Issues Concerning the Transportation of Natural Gas":

I.A.1. (a) The current estimate of proven reserves of gas in the Prudhoe Bay pool, consisting of the closely related Sadlerochit, Sag River and Shublik Formation, is 24 trillion cubic feet.

(b) No other hydrocarbon-bearing formations in the Prudhoe Bay field are, at this time, considered to contain proven reserves of gas.

(c) & (d) BP Alaska does not have sufficient data to establish whether proven reserves of gas exist elsewhere in Arctic or interior Alaska or on the Arctic OCS or in the Mackenzie Delta and adjacent Canadian onshore and offshore areas.

I.A.2. BP Alaska does not have sufficient data available to make any reasonable predicition of the volume of additional gas reserves that may be discovered and produced from these areas by 1985.

I.A.3. (a) Geological and engineering data would suggest that the uncertainty in the reserves estimate given in I.A.1. (a), above, is approximately ±15%.

(b) & (c) As we are unable to make any reasonable prediction of the volume of gas reserves in areas other than in the proven acreage of Prudhoe Bay, the estimates are not sensitive to factors listed in this question. There can be no doubt that leasing and other policies that give real incentives for active exploration and development work will increase the prospects of additional gas reserves being discovered and proven.

I.A.4. We have made no estimate of the potential gas reserves of the areas listed that could be considered to be reliable,

nor have we evaluated the effect these might have on transportation systems for Prudhoe Bay gas.

I.A.5. BP Alaska is not directly involved in any gas pipeline ventures and therefore is not best qualified to respond to this question. Any leasing and development policies that give incentives for active exploration and production should lead to a situation where more data will exist to evaluate the possible alternative transporation systems.

I.B.1. When a gas pipeline is constructed and available to transport gas from the Prudhoe Bay field, sometime after the commencement of oil production, the field should be able to produce sales volumes of about 2 to 2.5 billion cubic feet of gas per day. These rates should be sustained by the operation of the field under an overall reservoir management scheme with pressure maintenance by water injection being applied and continued as necessary.

I.B.2. Until further information is available from both reservoir data and production history, there will remain some uncertainty as to the reservoir management necessary to sustain the offtake rates quoted. However, BP Alaska considers that offtakes within the range given can be sustained with appropriate development drilling and facilities installation, and with pressure maintenance as necessary so that there will be no significant loss of ultimate oil recovery.

I.B.3. BP Alaska has not yet received the full Van Poollen report and therefore is unable to comment on the implications in that study. Experience from production history and tests will enable the operators in the field to more precisely design a management scheme that will enable the field to be efficiently produced to sustain the planned offtake rates. We do not consider that any trade off between gas and oil production is implied by recognizing that this additional data will enable the operators to refine or revise their development plans.

I.B.6. It is not currently possible to estimate reliably what the ultimate cost of the facilities to be installed for gas production will be, nor, without any experience, what the exact operating costs might be until gas production commences. Both the unique nature of the location and the current trend

of escalating costs make any reliable estimations difficult. Further such direct costs should not be viewed in isolation from the overall costs of exploration for the discovery of this gas and the taxes that will be applied.

II.A.3. BP Alaska has entered into an agreement with Northern Natural Gas Company, which gives them the option to purchase the as yet undefined volumes of gas that may be attributed to BP Alaska through the BP Alaska/Sohio net profits interest agreements, up to a maximum volume of 3 trillion cubic feet. BP Alaska has not entered into any agreement which concerns the basis or method of transport of the gas which Northern Natural has the option to purchase, or any other gas that may be available to our company on the North Slope.

BP Alaska also has made similar commitment to Columbia Gas Transmission Corporation with respect to any Prudhoe Bay gas not required to satisfy its undertaking with Northern Natural Gas.

II.B.2. (a) As indicated previously, BP Alaska has granted to Northern Natural Gas an option to purchase up to 3 trillion cubic feet of gas attributed to its net profits interest in Prudhoe Bay leases, held by Sohio, and some of BP Alaska's other leases on Alaska's North Slope. The amount of Prudhoe Bay gas owned by BP Alaska is related by contract to the time and volume of sustained oil production from Prudhoe Bay, and also is related to the level of oil produced at specific times. The total amount of Prudhoe production also is dependent upon unitization and production methods, all of which makes it impracticable, if not impossible, for Northern to exercise its option until the Prudhoe field goes on production.

(b), (c) & (d) Northern's option provides for good faith negotiations of the price and other terms at the time gas is available for purchase.

BP Alaska also has made similar commitment to Columbia Gas Transmission Corporation with respect to any Prudhoe Bay gas not required to satisfy its undertaking with Northern Natural Gas.

PRUDHOE BAY FIELD

SADLEROCHIT SAND RESERVOIR OIL DATA ---JOHN HUBER

ANALYSIS OF STOCK TANK OIL SAMPLES

H_2 S-% wt.	NIL
SULPHUR % WT	0.95
POUR POINT	27.5°F.
KINEMATIC VISCOSITY (CENTISTOKES)	
50°F.	53
70°F.	26
100°F.	12.6
GRAVITY API	27.9
VANADIUM ppm	13.5
NICKEL ppm	7
WAX % WT	6.3
MELT PT WAX°F	135
% DISTILLED 150°C.	9.5
" 200°C.	17.5
" 300°C.	38.0

SEPARATOR GAS DATA

	PRESSURE (psia)	TEMP.	GOR.	GAS SP. GR.	S.T.O. GRAVITY
1st	615	130	620	0.785	
2nd	100	120	130	0.950	
3rd	15	115	37.7	1.33	0.8864
			787.7		(28.13°API)

SEPARATOR GAS MOL %

	1st	2nd	3rd
CO_2	15.27	18.75	12.91
N_2	0.75	0.23	0.03
C_1	73.94	55.66	24.03
C_2 - C_9	10.04	25.36	63.03

NOTE HIGH CO_2 CONTENT

RESERVOIR TEMPERATURE - 200°F.

AGO 545886

REPORT ON METHANOL/METHYL FUEL

Prepared for: Senator John Huber

By: Franklin D. Fleeks

AGO 545887

Introduction

Along with the discovery of the Prudhoe Bay oil field came the discovery of a vast pool of gas located at the same field. In order to exploit and remove this resource various schemes have been brought forth. The focus has been on removal by a gas pipeline. The Legislature formed the Joint Gas Pipeline Impact Committee to make a thorough study to help formulate and implement necessary policy decisions.

While gathering its data, questions have arisen dealing with (1) competing gas line proposals, (2) how to handle the state's royalty gas, and (3) problems with federal regulatory agencies. In a thought-provoking report, the consultant to the Committee -- Rush Moody, Jr., succinctly outlined the federal problem. If natural gas is sold in interstate commerce, regulation will be done by the Federal Power Commission. Whether or not the state's royalty gas is initially taken "in kind" it is more than probable that when a later request is made, the state could not withdraw its royalty share without FPC approval.[1]

Considering the current regulated price of gas and the degree of possible federal interference with Alaska's policy regarding its natural gas resource, several alternatives have been looked at. Senator Huber, a member of the Joint Committee, has pursued an alternative based on conversion of the gas to methanol/methyl fuel.

We use methanol here for convenience. The proper term should be methyl fuel, a liquid consisting principally of methanol, produced catalytically from synthesis gas, a mixture of hydrogen and carbon monoxide.

What is Methanol/Methyl Fuel and Its Uses

Methanol/Methyl Fuel or methyl alcohol, CH_3OH, is a colorless, neutral liquid at ambient temperature with a mild odor.[2] In its earliest form, it was called "wood alcohol." It is a clean burning stable fuel which can be converted from natural gas and coal. It can be shipped in conventional tankers and stored in conventional tanks.

The versatility of methanol is clearly shown in the use that can be made of it. Some of its more important uses currently and in the future are:

(1) Directly as a liquid boiler fuel;

(2) Turbine fuel;

(3) In automotive fleets;

(4) Petrochemical feedstock;

(5) Development of Alaskan coal resources.[3,4]

Chemical Feedstock

As Exhibit 1 shows, methanol/methyl fuel can be converted into a number of chemicals having commercial value. The methanol/methyl fuel produced from Alaskan gas and coal resources can create an array of downstream petrochemical industries. With the decrease of hydrocarbon feedstocks based on natural gas in the lower 48 there is a market for methanol/methyl fuel produced from Alaskan coal and gas.

Gasoline Additives

Methanol/methyl fuel can be used as a gasoline additive or as a substitute for gasoline.

As an additive, methanol/methyl fuel will decrease current gasoline consumption on a barrel for barrel basis. According to available information, there is no fall off in fuel efficiency up to approximately ten percent blend levels.[5] Methanol/methyl fuel, however, has about half the heating value per gallon when compared to gasoline. Comparison of some of the properties of methanol/methy fuel and gasoline are shown in Exhibit 2.[6] A bill, introduced in the California Legislature in 1975, would require the addition of methanol to gasoline sold in the state.

Methanol/methyl fuel can effectively reduce the level of pollutants caused by automotive emissions.[7] From a study carried out by the Lawrence Livermore Laboratory in 1974 the following is given:

> ". . . The health effects on man as a consequence of emissions from methanol as compared to gasoline fired automobiles can be summarized as follows: (1) reduction in adverse health effects of photchemical smog as a consequence of reduced photoactivity, (2) elimination of the possibility of lead toxicity to children and other sensitive individuals, because no lead is needed to boost the octane number (3) aromatic emissions from automobiles will be drastically reduced, reducing the carcinogens released to the atmosphere, and (4) reduce exposure to sulfuric acid mist. . ." 8

One of the crucial elements in the gas pipeline/methanol energy debate is what is the net effective energy. If methanol is added in at ten percent blend it will increase the efficiency of energy used in the automobile.

> -". . . (The) maximum BTU's available from the estimated Prudhoe Bay maximum gas production is 2.36 trillion BTU/degrees. That same gas, transformed into methanol at the wellhead would yield at least 514,000 bbl of methanol. Transported to the lower 48 states at no BTU shrinkage . . . it would displace 514,000 bbl of gasoline in a ten percent blend. Gasoline has a BTU content of 514 million BTU per bbl so the net gain in effective energy in the transportation part of the lower 48 market would be 2.7 trillion BTU/day. This is more than the natural gas delivered BTU's of heating value. . . ." 9

Industrial or Electrical Utility Fuel

The use of methanol/methyl fuel as a liquid boiler and liquid turbine fuel is currently feasible. Tests have been carried out by the electrical utility industry which show that turbines perform more efficiently on methanol/methyl fuel. Although twice as many gallons of methanol/methyl fuel must be burned to provide the same number of BTU's as oil, turbines burning methanol/methyl fuel generate up to six percent more power per million BTU's.[10]

Transportation of Methanol/Methyl Fuel

The transmission of methanol/methyl fuel to a shipping point for transport to potential markets can be done in a variety of ways. After conversion at Prudhoe Bay, it can be shipped on a batch basis through the Alyeska pipeline, a common carrier.[11] The enabling legislation for the Alyeska Pipeline project (PL 93-153) allows for transportation of synthetic or gaseous fuels through the Alyeska Pipeline.[12] Also a pipeline could be built entirely for methanol/methyl fuel and other synthetic or gaseous fuels.

Once the methanol/methyl fuel reaches tidewater it can be shipped in conventional tankers. Unlike liquified natrual gas (LNG) methanol/methyl

fuel does not need special tanker ships to carry it or special storage facilities. Present proposals call for the transportation of natural gas by pipeline to Gravina Point where it will be liquified for shipment via tankers (to be built) to its demand markets.[13] Use of conventional tankers in transporting methanol/methyl fuel can cut into the lead time needed to get the product from the gas field to market.

Methanol/Methyl Fuel Concept Effect on Alaska

One immediate effect would be to remove the gas from FPC jurisdiction. In Mr. Moody's letter of January 14, 1976, he concluded:

> ". . . if North Slope gas is converted to methanol before becoming committed to interstate commerce, the conversion facilities, the methanol itself, and the transportation of methanol would not be subject to FPC control. Since the natural gas would be produced and "consumed" (i.e., converted to something other than natural gas) within the state, the natural gas would never become subject to FPC jurisdiction. . ." 14

For Alaska, one of the most promising concepts that methanol/methyl fuel opens up is the possibility of using the state's coal resources. By taking the state's royalty gas in kind and transporting the gas to the vicinity of the major Alaskan coal fields, especially those near tidewater, a new industry can be developed.

The coal and gas mixture increases the conversion to methanol/methyl fuel by approximately ten percent. The building of the methanol/methyl fuel plants will provide an infrastructure that will be in place once the natural gas resource is depleted. That infrastructure will be available to further develop the state's coal resources. The building

of the methanol/methyl fuel plants will provide needed energy for the state, increase employment, and provide the industrial infrastructure needed to develop one of the state's most abundant resources, coal.

Conclusion

From review of the literature and studies, most of the data presented is in a prospective form. Even though prospective, the production of methanol/methyl fuel using Alaskan gas is feasible and should be pursued as a viable alternative. The methanol/methyl fuel concept will negate federal regulation, provide a substitute to help alleviate the nation's energy problems and protect the environment by reducing pollutants. The market for industrial chemical uses is not yet defined. However, the net quantities of methanol/methyl fuel produced from Alaskan natural gas can be absorbed by the electrical utility and automotive markets. Continued study should be made of the methanol/methyl fuel concepts.

FOOTNOTES

1. Rush Moody, Jr., Legal Analysis of Issues Relating to Natural Gas Transportation, 64 (1976).

2. Lecture, Methanol -- Feedstock for the Chemical Industry and Fuel of the Future, Tiemann and Raghuraman, Selas of American, April, 1973.

3. Alaskan Methanol Concept -- A Pre-Feasibility Study, Institute for Energy Analysis, Oak Ridge Associated Universities, IEA Research Memorandum, 75-5, Nov., 1975.

4. The Clean Synthetic Fuel That's Already Here, E. Faltermeyer, Fortune Magazine, Sept., 1975, 147.

5. Alaskan Methanol Concept, supra.

6. Methanol -- The "New Fuel" from Coal, Mills and Harney, Chemtech, January, 1974, 26.

7. Arctic Energy A New Perpesctive, Westinghouse Oceanic Division, January, 1976, 42.

8. Paper, Environmental Aspects of Methanol as Vehicular Fuel: Health and Environmental Effects, Beverly J. Berger, Lawrence Livermore Laboratory, Sept., 1974, 4-5.

9. Arctic Energy, A New Perspective, supra, 50.

10. Faltermeyer, supra, 150.

11. Alaska Methanol Concept, supra, 66.

12. Arctic Energy, A New Perspective, supra, 10.

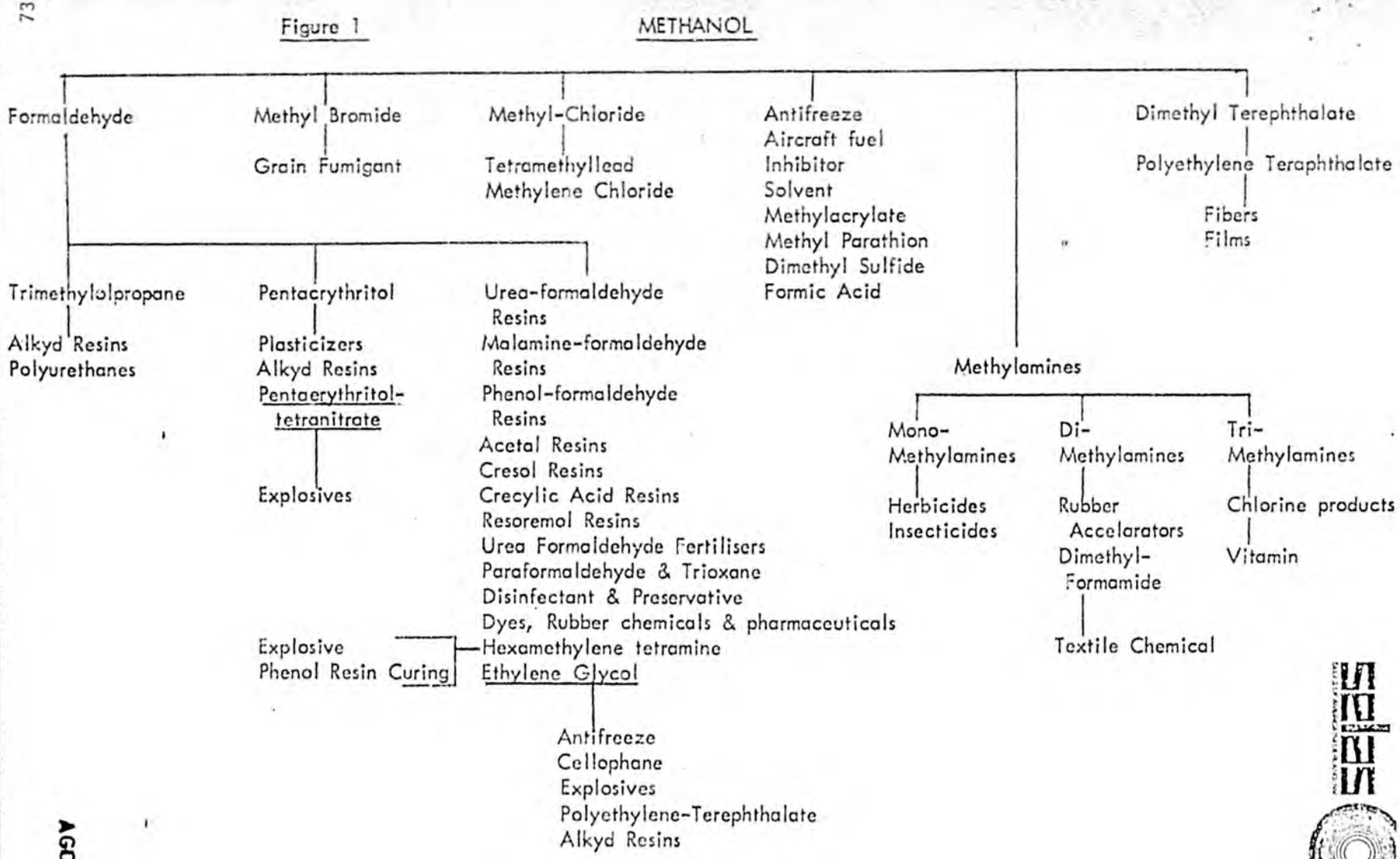
13. Trans-Alaska Gas Pipeline Project, State of Alaska, Department of Labor, December, 1975, 2.

14. Moody, Jr., Cover letter, supra, 8.

EXHIBIT 1

73

Figure 1



SELAS OF AMERICA (NEDERLAND) N.V.

AGO 545895

EXHIBIT 2

COMPARISON OF METHANOL AND GASOLINE

	Methanol	Gasoline
Formula	CH_3OH	$C_4H_{10}C_{12}H_{26}$
Boiling point, F	148	100-400
Freezing point, F	-144	-100
Latent heat of vaporization at bp BTU/lb	502	116
Liquid density 16/gal.	6.6	6.2
Heat of combustion (liquid-fuel-liquid H_2O) BTU/lb.	9,776	20,260
BTU/gal.	64,500	124,800

Source: Mills and Harney, Methanol -- The "New" Fuel" from Coal; Chemtech, January 1974, 27.

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February 13, 1976

Senator John Huber
Chairman,
Special Committee on Taxation and Revenue
Alaska State Legislature
Pouch V
Juneau, Alaska 99811

Dear John:

Thank you for sending me a copy of the Rush Moody report on "Legal Analysis of Issues Relating to Natural Gas Transportation." I did indeed find it quite interesting and informative. While I am not competent to comment on the legal issues analyzed, I am happy to respond to your request for comments or recommendations on the report, as it may touch on economic questions. This letter represents my initial reaction to some of these matters:

1. As I understand the Moody report, a key legal conclusion is that the State should take royalty gas in kind rather than in value; otherwise, it may lose control in the future of this royalty gas because it will come under FPC regulation, and thus it would be possible that none of Alaska's natural gas would be available for consumption within the State.

2. From an economic point of view, I think the State would also be wise to take royalty gas (and maybe royalty oil also) in kind, so as not to lose the future option on having the royalty gas. This is particularly true because the real value of the royalty gas to the State may be much higher than its market value, for the following reasons.

3. First, at present the price of FPC regulated natural gas moving in interstate commerce is about one-fourth its real market value, as measured by prices on intra-state sales (50¢ versus $2.00 per MCF). While natural gas prices may be deregulated in a few years, there is no present certainty on this.

4. More important, in the long run I think it is generally agreed that the use of natural gas for its heat content as a fuel is a waste of a valuable resource, since its greatest value would be as a petrochemical feedstock. This suggests among other

things that over the long run natural gas prices will rise as it increasingly is reserved for its more valuable use.

5. But, because of the high profit rates the oil companies use in their DCF calculations (as discussed at length in my report), their decisions will tend to be made on short run profit considerations, which may not be best for the State. By way of hypothetical illustration, I constructed a case to show where it might be better for the State to have the gas stay in the ground until it became more valuable, while for the companies it would be more profitable to produce quickly. The hypothetical assumptions were that natural gas would sell at $2 per MCF in the 1980s, $6 per MCF in the 1990s, and $18 per MCF thereafter. Assuming a time value of money, or discount rate, for the companies of 20% per year and for the State of 10% per year, it turns out that if a gas field has a 20 year life, the companies would be best off producing all the gas in the 1981-2000 period, while the State would be better off with the gas produced in the 1991-2010 period. (See attached table.)

6. The problem of the State having a lower discount factor, and hence a longer time horizon, than the companies is of course a general one which may lead to conflicts of interest in many oil and gas areas. Thus, for example, it may be better for the State if all oil and gas were produced at a slower rate than the companies would like, and it is possible that this could be handled under conservation regulations. Specifically, however, with regard to its royalty gas, if the State decides it would be better off with gas production at a slower rate than the companies want, perhaps a way could be worked out to require the companies to leave the royalty gas in the ground until the State requests it, either for its own use or for resale. Alternatively, the State could perhaps exchange the royalty gas with companies for "future gas" to be delivered by them when desired by the State.

7. Another factor favoring taking of royalty gas in kind is that market prices of gas may not reflect the full economic cost to the State of not having the gas. In the short run, a lack of gas could mean costly shutdowns of industry and great consumer inconvenience. In the long run, the absence of an assured supply of gas might hinder the whole economic development of the State. Thus, the question of royalty gas cannot be divorced from questions of planning long-run economic development. But, at least keeping the option to take gas in kind does not foreclose future industrial development opportunities.

8. Also, I think taking royalty gas in kind would have the advantage that it will help the State learn more about the oil and gas business, from practical experience. With oil companies fully integrated from the raw material through petrochemicals, and with the allocation of costs between oil and gas production,

and between raw material production and other functions, often being arbitrary, it is important for the State to have a good grasp of the practical economics of the gas business as well as the oil business. This is vital for the State even if it is to simply maximize its benefits as a tax collector.

9. Finally, I certainly agree with the Moody Report's general recommendations that State leasing policies and taxation on natural gas should be reconsidered. In my opinion both of these questions call for detailed study of possible alternatives. Here I would only observe that tax rates in Texas and Louisiana, where the oil companies have widespread political support from small producers, would not normally be an adequate yardstick as to what rates of taxation could be imposed.

I hope these general comments will be of use to you. My thanks also for your kind words about my report.

Yours sincerely,

Michael Tanzer

Dr. Michael Tanzer,
President

ALASKAN NATURAL GAS PRODUCTION: HYPOTHETICAL EXAMPLE ILLUSTRATING POSSIBLE CONFLICT OF INTEREST BETWEEN THE STATE AND THE COMPANIES OVER TIMING OF PRODUCTION

Assumptions:

(1) Prices of natural gas ($ per MCF): 1981-90, $2; 1991-2000, $6; 2001-2020, $18.

(2) Ignore in all cases investment and operating costs (Alternative interpretation: Prices are net of costs).

(3) Potential production = 1 MCF per year for 20 years.

(4) Discount factors for computing present value in 1980 of future income from gas: companies, 20% per year; State, 10% per year.

TOTAL VALUE OF INCOME FROM
20 YEARS OF GAS PRODUCTION ($):

	1981-2000	1991-2010	2001-2020
A. Gross Value (undiscounted)			
(a) First 10 years	20	60	180
(b) Next 10 years	60	180	180
(c) Total 20 years	80	240	360
B. 1980 Present Value, Discounted at 20% per year (company rate)			
(a) First 10 years	8.39	4.06	1.96
(b) Next 10 years	4.06	1.96	.32
(c) Total 20 years	12.45**	6.02	2.28
C. 1980 Present Value, Discounted at 10% per year (State rate)			
(a) First 10 years	12.29	14.22	16.43
(b) Next 10 years	14.22	16.43	6.32
(c) Total 20 years	27.51	30.65**	22.75

** = Most profitable production period

METHYL-FUEL

Wentworth Brothers, Inc.

Cincinnati, Ohio

AGO 545902

At the onset, I would like to very briefly outline the METHYL-FUEL concept.

At the present time, the total installed world's methanol production (chemical grade) is about 25,000 short tons, (a short ton contains about 7.2 API barrels, or just over 300 gallons). This capacity consists of about 5,000 tons in Japan with the balance about equally split between the U.S. and the balance of the world.

In the U.S., our personnel have designed about 30-35% of the installed capacity, including the current worlds largest chemical grade plant (2,500 TPD) down in Beaumont, Texas.

In part stemming from the later plant, and recognizing the large volumes of associated gas being flared in remote locations, the METHYL-FUEL concept was brought forth as a means to bring this energy to market in a stable liquid form. Events in 1973, the Middle East war, temporarily brought a halt to this endeavor in many parts of the world.

This then prompted a renewed look at producing METHYL-FUEL from our nations coal reserves.

When considering coal as feedstock, one is forced to consider the environmental unacceptable coals, the low quality coals or the marginal coals in remote locations. Good, high quality coal should be used as is.

A brief while back, it was brought to our attention that significant quantities of coal existed in Alaska. Very preliminary studies indicated that these coals can be quite economically converted to METHYL-FUEL and transported as a liquid to distant markets. Through this work, the melding of possibilities came forth wherein the production of METHYL-FUEL from the State's coal and/or from the State's coal and gas, appears to offer a very attractive situation. Examples:

1. The synthesis gas from coal for METHYL-FUEL production is deficient in hydrogen. Synthesis gas from natural gas is deficient in carbon. This brings forth the prospect of a optomized combination coal and gas fed plant with thus a considerable increase in conversion efficiency.

2. Many of the Alaskan coals appear to be the type that would lend themselves to simple coal beneficiation. This brought forth the concept wherein, for example, two tons of coal would be mined, one ton would be upgraded to a dehydrated, low sulfur, high BTU coal, the other ton (or the reject from the beneficiation) would serve as METHYL-FUEL feedstock. The METHYL-FUEL would then be utilized as the slurrying media for the beneficiated coal. This not only results in further increases in conversion efficiency, but permits very economical transport of the beneficiated coal and a most appropriate use of gas and coal in the State.

3. It is understood that the gas with Alaskan crude contains a rather large amount of carbon dioxide (CO_2). For METHYL-FUEL production, this presence of CO_2 is a benefit in that it does not have to be removed to permit METHYL-FUEL production, but rather augments it and becomes of the product -- METHYL-FUEL.

4. It is understood that the Alaskan associated gas contains a fair amount of LPG (Propane and Butane) and natural gas liquids (iso pentane and heavier). Our firm has a proprietary process wherein the butane and heavier liquids can be handled very economically with METHYL-FUEL with no loss in conversion efficiency for these stocks. This concept can thus result in the elimination of the waste in at least one, perhaps two, or even three of the other energy systems that will result. The capital and operating cost

savings that are possible here can be quite outstanding. Also, it is this point that makes comparison of METHYL-FUEL handling with other gas handling alternatives about like comparing "apples with oranges" -- with the apples in this case being much more valuable than the oranges because of the inherent case in handling METHYL-FUEL.

5. Last, but not least, is the further processing on the Alaskan scene of the byproducts from a METHYL-FUEL complex with the value added benefits to Alaska. The ones that immediately suggest themselves are ammonia, urea, the ammonium nitrates and the many -- many drivatives possible from the chemical grade alcohols. In summary, it is believed that METHYL-FUEL should be given serious consideration in Alaska. The benefits resulting are many, and far reaching; i.e.:

A.) METHYL-FUEL from coal will in effect revive an old industry and initiate a new vibrant Alaskan industry.

B.) METHYL-FUEL from coal and gas will start and establish an infrastructure which, when the gas reserves are depleted the quantities of coal remaining will permit an on-going clean energy supply situation into the next century.

C.) The existance of a METHYL-FUEL facility will permit consideration of a vast downstream petro-chemical complex for products which in their own right may not otherwise be economically viable.

STANFORD RESEARCH INSTITUTE
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LNG, METHANOL, FISCHER-TROPSCH SYNTHESIS: METHODS OF UTILIZING REMOTE NATURAL GAS

SRI has recently completed a $300,000 technoeconomic study on this subject. This in-depth study is sponsored by 40 companies from 16 countries.

At the present time, trillions of cubic feet of natural gas are being burned uselessly in flares in remote oil fields in the Middle East, Africa, South America, Indonesia, and elsewhere. Remote natural gas fields have not been developed because of lack of markets.

The economical utilization of remote gas would be attractive to both the exporting and importing countries. Schemes previously considered uneconomical for transporting and utilizing this gas are now being seriously proposed. The two most commonly suggested means of utilizing remote natural gas are liquefaction of the gas to LNG or conversion to methanol and transportation of the liquid product to the market. Several LNG projects are in operation or planned for utilizing natural gas from Algeria, Libya, Brunei, Indonesia, Nigeria, and Alaska. Proposed fuel methanol-from-gas projects have been announced for Middle East gas.

Less attention, however, has been given to other methods of utilizing remote gas. These methods include:

- Fischer-Tropsch liquid fuels
- Long distance natural gas pipelines
- Petrochemical manufacture.

This study includes technical and economic evaluations of all of these options for various distances between producing and consuming regions.

The cost of this study is US$8,000.

AGO 545906

STANFORD RESEARCH INSTITUTE
MENLO PARK, CALIFORNIA 94025
(415) 326-6200

November 6, 1975

Senator John Huber
Pouch V
Juneau, Alaska 99811

Dear Senator Huber:

As I promised at our meeting here last month, I am sending you the Table of Contents of our recently issued report, "LNG, Methanol, Fischer-Tropsch Synthesis: Methods of Utilizing Remote Natural Gas."

If you have any questions, please contact me.

Sincerely,

Jim Moll

A. James Moll, Director
Energy Technology Department

AJM/jlb

Enclosure

cc: Anchorage, Alaska

CABLE: STANRES, MENLO PARK / TWX 910-373-1246

CLIENT PRIVATE

STANFORD RESEARCH INSTITUTE
Menlo Park, California 94025 · U.S.A.

October 1975

LNG, METHANOL, FISCHER-TROPSCH SYNTHESIS: Methods of Utilizing Remote Natural Gas

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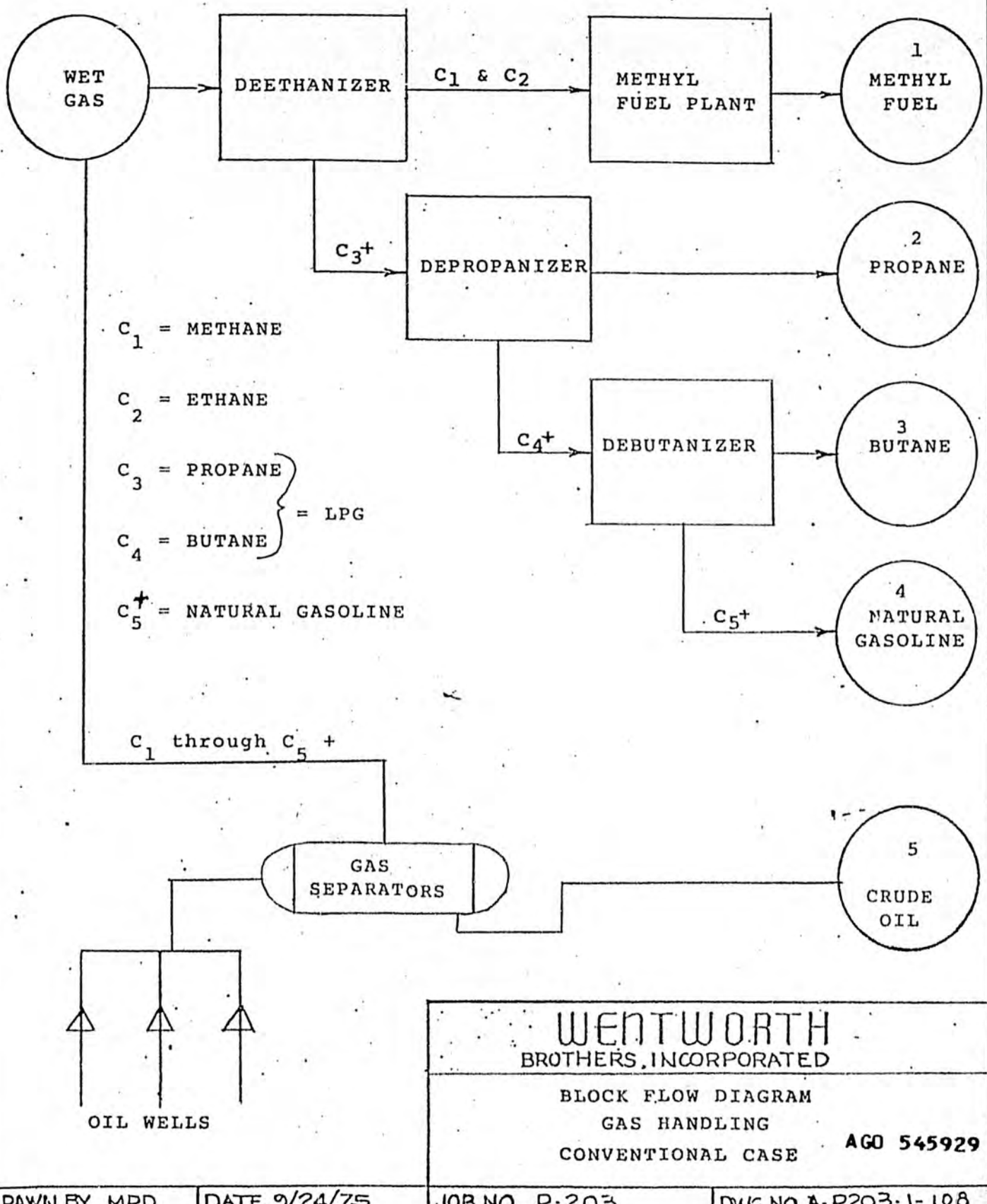
SYSTEMS



WENTWORTH BROTHERS, INCORPORATED

BLOCK FLOW DIAGRAM
GAS HANDLING
CONVENTIONAL CASE

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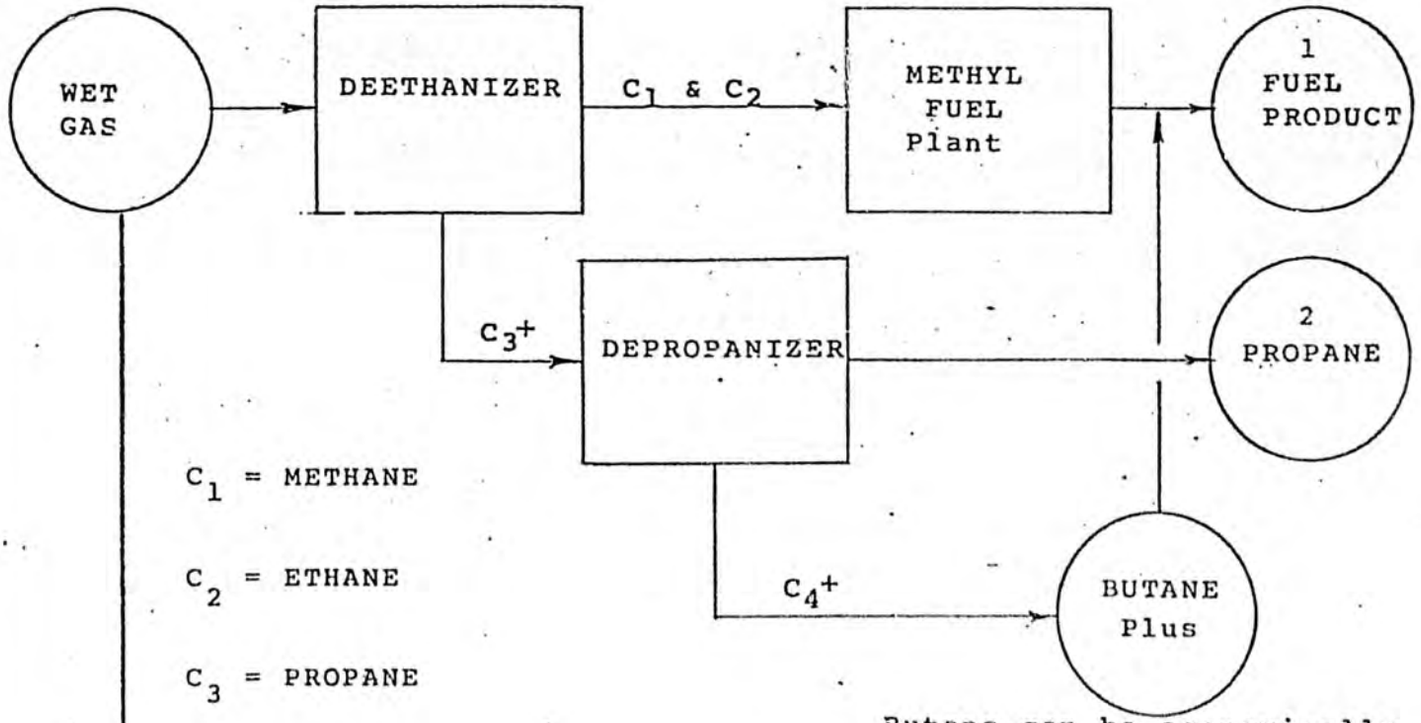


C_1 = METHANE

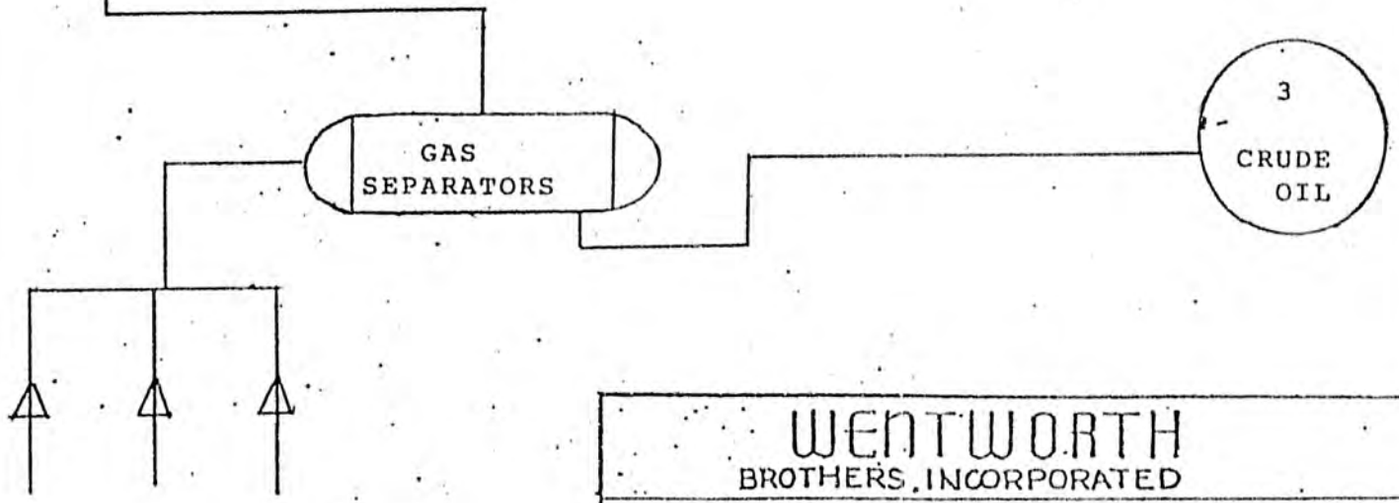
C_2 = ETHANE

C_3 = PROPANE

C_4 = BUTANE

C_5^+ = NATURAL GASOLINE

Butane can be economically recovered at the receiving port



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BLOCK FLOW DIAGRAM

GAS HANDLING ALTERNATIVE I

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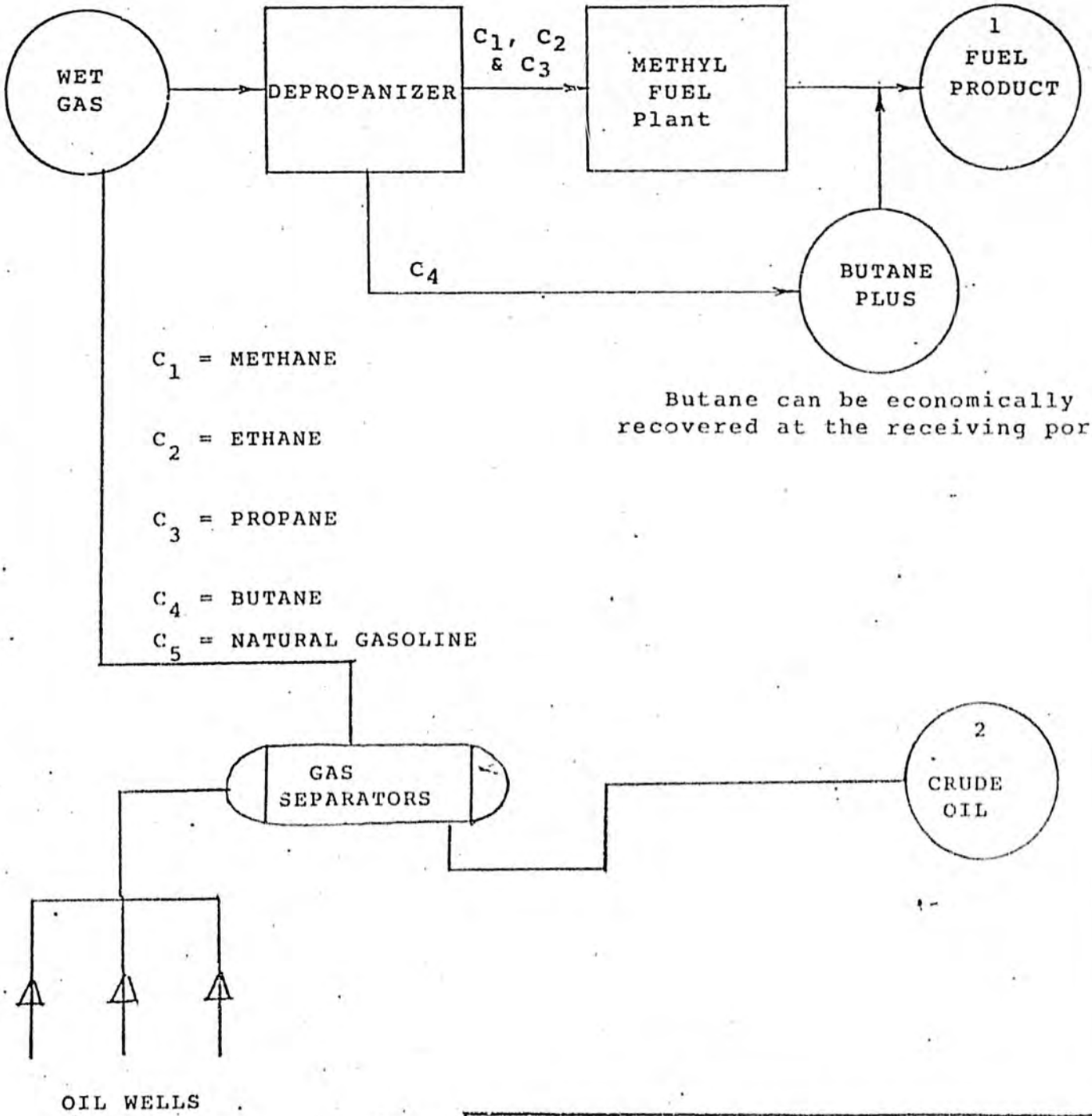

Butane can be economically recovered at the receiving port

WENTWORTH BROTHERS, INCORPORATED

BLOCK FLOW DIAGRAM
GAS HANDLING
ALTERNATIVE II

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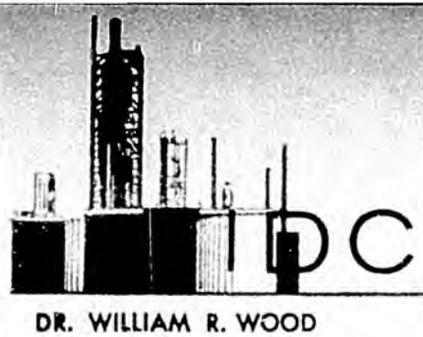



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February 5, 1976

Senator John Rader, Chairman
Joint Gas Pipeline Impact Committee
Alaska State Legislature
Juneau, Alaska, 99801

Dear Senator Rader:

The undersigned, representing a number of leading labor, business, professional, and industrial groups and more than seven thousand jobs for as many thousands of workers and their families in the Fairbanks area, have studied with deep interest the "Moody Report" submitted to your committee on 14 January 1976.

We heartily commend your foresight in authorizing a study of such fundamental significance for all Alaskans. Your selection of Mr. Rush Moody, a former member of the Federal Power Commission, to conduct the analysis of Alaska's natural gas issues was most wise and fortunate.

Mr. Moody's informative, forthright, yet restrained and objective report to you and your committee clearly reflects the deep-seated concerns of the Alaska tax-paying residents whom we represent. With all of the complexities involved, including the authority of the FPC to fix the well-head price of gas, conceivably Alaska could derive little or no benefit from its great store of natural gas, a rare and precious commodity in the world today. Specifically, we endorse the following basic ooncepts presented in the Moody Report:

1. "The State should pursue an affirmative, aggressive course of enlightened self-interest" to meet its present and future natural gas needs.

2. The State should "place less emphasis upon direct revenue and more emphasis upon cooperative development" with the private interests involved in exploration, extraction, transportation, processing in Alaska, and marketing to insure that Alaska "share in the benefit of a secure and reliable source of natural gas for use as a non-polluting heat source and as a raw material feedstock." In particular, it is essential that the State establish forthwith a stable business climate conducive to such cooperation with potential purchasers or processors of Alaska royalty gas.

3. The State should adopt a basic energy policy that will encourage and stabilize interest in the wisest possible use of its natural gas resources, emphasizing processing within the State to provide the benefits of meaningful and productive employment opportunities for Alaskans on a long-term basis. Such basic policy is required for orderly and economical development of both present and potential commercial oil and gas fields of Alaska.

4. The State should consider in depth the advantages to be gained by the "enactment of legislation to hold State owned resources within the State unless ... surplus to the needs of the State" and thus encourage the making in Alaska of more of our own consumer products through the good use of our own human and other natural resources.

5. Since "a natural gas stream has enormous potential value", the State should promptly and aggressively explore all potential uses ... " where conversion within the State, or liquids extraction within the State" strengthens the State's control of its own resource and ... diminishes the range of FPC controls." Especially the State might well consider how best to arrange for the conversion of natural gas to methanol and ways of removing butane, propane, and other LPG's "from the natural stream prior to transportation or sale in interstate commerce."

We pledge our full support of prompt and responsible legislative action as suggested in the conclusion stated in the Moody Report that will effectively secure for Alaskans the

opportunity to make the best use of the State's natural gas resource. It strikes us as an urgent necessity that strong action on these vital issues be taken now without further delay. Clearly, at this point the regulation and taxation are less significant than stimulation and encouragement to make wise use of our resources.

Sincerely yours,

Dave Rasley, Secretary-Treasurer
Central Labor Council

Wally Baer, General Manager
Chamber of Commerce

James Kelly, Manager, Fairbanks Chapter
Associated General Contractors

John C. Morris, M.D., Fairbanks
Chairman, OMAR

J.A. Kornfeind, Manager, Alaska Chapter
National Electrical Contractors Assn.

Al Seeliger, Secretary-Treasurer
Fairbanks Industrial Development
Corporation

WRW/kb
cc: Members, Committee
Senator J. Butrovich
Representative F. Brown
Senator T. Stevens
Senator M. Gravel
Congressman D. Young
Governor J.S. Hammond
Commissioner L. Motley
Commissioner G. Martin

OUTLINE OF TESTIMONY TO THE GAS PIPELINE IMPACT COMMITTEE

I am Thomas R. Stahr, Manager of the Municipal Light and Power Department (ML&P) of the Municipality of Anchorage. I am testifying on behalf of the Municipality of Anchorage.

Municipal Light & Power consumed 6.3 Billion cubic feet (BCF) of natural gas for electric power generation in 1975. Our projections indicate 14.6 BCF of gas will be required by 1985. The projected figure is based on the use of waste heat recovery and other conservation measures. Significant improvements in efficiency cannot be anticipated beyond then so the annual increase in usage will be somewhere between 6 and 12%, 8-9% appearing as most likely unless major hydro power projects are built. In the latter case, natural gas consumption for power generation will likely decrease somewhat.

Alaska Gas and Service Company states their total sales are approximately 30 BCFfor all purposes and anticipate a one BCF increase annually. It is our (ML&P) opinion they have slightly under-estimated the increase in electric power generation but the difference is not critical.

The Stanford Research Institute in their report titled "Natural Gas Demand and Supply to the Year 2000 in the Cook Inlet Basin of South-Central Alaska" projects a household-commercial usage of 55 BCF by the year 2000 and requirements for electric power generation as high as 150 BCF per year. Based on the previously cited study and general considerations it appears that the local needs of the area plus the proposed exports cannot be supported over the next 25 years by the now known reserves in the Cook Inlet area. While it is likely that additional local sources will be found, there is no certainty to this. Even if Hydroelectric power becomes available we certainly do not have a secure energy future unless additional reserves are secured. I believe the needs of Alaska should be served before our energy resources are irretrievably committed to others.

Commissioner Guy R. Martin
Chairman, Alaska Royalty Oil and Gas
Development Advisory Board
Department of Natural Resources
Juneau, Alaska

I have been authorized by the El Paso Company to make a formal proposal to purchase the State of Alaska's royalty gas which is excess to the State's needs in Alaska. The following is a draft Memorandum of Agreement which sets forth El Paso's proposal:

(Quote)
WHEREAS, THE EL PASO COMPANY (El Paso), either singly or in conjunction with others is willing to construct and operate facilities to transport natural gas in a large diameter pipeline from the North Slope of Alaska across Alaska to a point on the south central coast, providing outlets for markets enroute, and thence by LNG tankers to markets in the lower forty-eight states ("The Alaska Project");

WHEREAS, the implementation of the plan contemplated by the Alaska Project is in the maximum interest of Alaska and the nation in coping with the critical energy shortage; and

WHEREAS, the State of Alaska ("the State") is entitled to take in kind its royalty share of natural gas produced on state-owned lands within Alaska ("Royalty Gas");

NOW THEREFORE, to the end that the Alaska Project may be realized and the State's objectives achieved, the parties hereto agree as follows:

1. El Paso agrees that the Alaska Project will be constructed and operated in a manner suitable to the handling of the State's Royalty Gas to achieve its objectives herein set forth;

2. The State, having indicated a desire to make its Royalty Gas available for use within the state, will authorize such gas to be delivered to the Alaska Project for transportation to such points along the route of the pipeline as it shall designate;

3. Those quantities of the State's gas determined by it to be surplus to its economic and sociological needs ("Surplus Gas") shall be sold to and purchased by El Paso at the terminus of the pipeline;

4. The charge for the transportation of the State's Royalty Gas shall be that fixed by the appropriate regulatory agency;

5. El Paso shall pay the State for the Surplus Gas at a rate equal to the highest price paid by any responsible purchaser from time-to-time for gas of which the State's Royalty Gas is a portion;

6. If from time-to-time the State shall have available to it additional quantities of Royalty Gas, El Paso agrees to transport and/or purchase such additional quantities of gas on the same terms and conditions set forth herein;

7. The term applicable to the purchase of the Surplus Gas shall be for a period of such years and for such amounts as shall be determined by the State to be surplus to its needs. The State agrees to quantify these amounts and to enter into a further definitive agreement to implement the Alaska Project within one month after signature of this agreement;

8. The State may withdraw any portion of its Surplus Gas from sale to El Paso whenever additional gas is made available to El Paso by others in a volume equal to that withdrawn by the State;

9. At the end of the term of the agreement which will be entered into pursuant to paragraph 7 herein, the State shall have the option to sell and El Paso agrees to purchase the volumes of such gas then determined by the

State to be surplus to its economic and sociological needs for an additional term of similar duration and upon the same terms herein set forth;

10. The undertakings of both the State and El Paso are subject to the receipt of all requisite government approvals, provided, however, that either party shall have the right to cancel this agreement upon thirty (30) days written notice to the other party if El Paso's application to construct and operate the Alaska Project is denied by the Federal Power Commission, or if the certificate which may be issued contains conditions which are unacceptable to El Paso, or to the State, or conditions which render El Paso unable to perform its contract with the State; and

11. At the appropriate time, the State and El Paso will execute a definitive agreement which shall incorporate the general principles covered by this Memorandum of Agreement and which shall include other terms and conditions as may be required and agreed upon.

DATED this _____ day of _____, 1975.

THE STATE OF ALASKA

By:_____

EL PASO COMPANY

By:_____

(End Quote)

Prompt execution of such an agreement will achieve the following:

A. Express to the Federal Power Commission the State's position on ownership of its royalty gas while being transported within Alaska.

B. Preserve the State's freedom to determine the best uses of its royalty gas within the State, while insuring a ready market for the surplus royalty gas.

C. Insure that the State receives the best price for its surplus royalty gas.

D. Demonstrate by affirmative action the State's support for the Trans-Alaska Gas Pipeline, thereby strengthening the position of El Paso in the current hearings before the Federal Power Commission.

If the Board wishes to revise the agreement, discuss its provisions with El Paso representatives, or requires additional data from El Paso, we are prepared to respond promptly.

Thank you for your consideration of our proposal.

JOHN C. BENNETT

VICE PRESIDENT

EL PASO ALASKA COMPANY

El Paso COMPANY

2727 ALLEN PARKWAY
P.O. BOX 2185
HOUSTON, TEXAS 77001

PHONE 713 524-3911

HOWARD BOYD CHAIRMAN OF THE BOARD

February 11, 1976

Senators Henry M. Jackson
and Warren G. Magnuson
United States Senate
Washington, D. C. 20510

Dear Messrs. Chairmen:

Thank you for the opportunity to contribute to the updating of your respective committees on the vital question of how and when Prudhoe Bay natural gas will reach the consumers of the United States. Enclosed are responses to the questions recently published by your committees. I hope you and your colleagues will find our contribution useful.

Having worked intimately with LNG projects for some thirteen years and having devoted five years of thought and effort to the Alaskan proposal, I hope you will find some general observations concerning El Paso's Trans-Alaska Project worthy of consideration.

There are many questions of fact which cannot be answered with absolute accuracy until a project of this unique magnitude has been undertaken. Costs of materials, wage rates, inflation rates, future taxation policies, reservoir deliverability--none of these facts can be finally determined five to six years before the project will come on-stream. Great effort has been expended to quantify such factors, but they will remain open to argument until actual implementation of the project refines the data once and for all. It is imperative that we focus on those major elements of decision-making which, unlike the details of execution, are now well known and which facilitate a response to the central question: How can Prudhoe Bay natural gas be delivered to American consumers?

There are basically four issues: timing, economics, environmental impact, and security.

First, there is timing. Any delay in bringing the gas to market will increase hardship throughout the country, escalate costs, and erode consumers' confidence in their governmental and industrial institutions. The trans-Alaska project will be completed sooner than the trans-Canadian project (Arctic Gas) for several major reasons:

-- The availability of Alyeska's haul road, work pads, camps, and equipment.

-- Only American approvals are required to launch the El Paso project.

AGO 545940

-- Litigation protesting the trans-Canadian project's crossing of the Arctic National Wildlife Range could delay construction for years.

-- Alaskan native claims are settled; agreement even to negotiate Canadian native claims is still in the future.

-- The critical cooperation of the State of Alaska is assured in expediting our project's execution.

-- The cooperation of American Labor is assured (44 national and international unions support our project).

-- The Department of Interior's "Report to the Congress" estimates that the risk of delay in completion of El Paso's project is half that of the trans-Canadian project.

The second issue is economics. The trans-Alaska project will benefit the United States as follows:

-- It will provide 9.3 billion dollars more in taxes to U. S. governmental entities than will be paid by the trans-Canadian project.

-- Were the trans-Canadian project approved, the American consumer would pay (at present tax rates) more than 7 billion dollars in Canadian taxes, versus zero for the trans-Alaska project.

-- It will provide more American jobs than will the trans-Canadian project--by a margin of 345,000 man-years.

-- El Paso has committed to procure all possible goods and services within the American economy, in contrast to billions of dollars to be spent by the trans-Canadian project in Japan, Canada, and Europe.

-- Interstate pipeline systems have not been able to add new supplies of gas sufficient to offset the decline in existing sources. The trans-Alaska project will utilize the idle capacity in these existing systems--presently being paid for by the American consumer--in bringing Alaskan gas to markets served by these systems.

-- If the Arctic Gas project is viewed under realistic assumptions, neither project would enjoy a significant advantage in the cost of transportation. If credit be given to the trans-Alaska project for the huge amount of additional U. S. taxes paid by it, the advantage is tilted in its favor. Construction changes and delays experienced in building across thousands of miles of unpenetrated hostile terrain selected by Arctic Gas could result in a dramatic advantage in favor of the trans-Alaskan route.

-- All of the U. S. consumers' payments for El Paso's transportation of gas will remain in the U. S. economy; under the trans-Canadian project, more than half of such payments would flow into the Canadian economy (for twenty-five years).

-- By redesigning certain of the liquefaction facilities, the "shrinkage" (consumption of natural gas) of the trans-Alaska project is substantially the same as the trans-Canadian project. However, in the trans-Alaska project, that portion of the "shrinkage" attributable to the transformation of gas into a mass of "super cold" will be available for future use in the making of industrial gases and in food processing, as now employed in connection with LNG projects in France and Japan, and for other uses.

-- All aspects of the trans-Alaska project over its entire life will be subject exclusively to the national interest of the United States as expressed from time to time by the U. S. Congress and implemented by the Federal Power Commission.

Third, the widespread support of El Paso's project among environmental groups (both American and Canadian) stems from persuasive facts:

-- While El Paso's pipeline will follow the routing of Alyeska's oil pipeline (in the most exhaustively studied corridor in the world), the trans-Canadian project would lay 5500 miles of pipe, much of it in new corridors in Canada and the United States.

-- The trans-Canadian project would require more than five times as many minor waterway crossings, and six times as many major waterway crossings as will El Paso.

-- Concerning LNG technology, the U. S. Coast Guard has reported that LNG shipment is among the safest seagoing operations being carried on today. LNG has been shipped for more than twelve years--covering more than 1400 deliveries--without a cargo release.

There is also the question of security--not in the sense of a threat of war, but peacetime requirements for pipeline security and the need for future expansion as other supplies of gas and oil in Alaska (e.g., NPR-4 and the Beaufort Sea) are produced:

-- The Department of Defense has concluded that the "Alaska-LNG route permits full U. S. physical control and does not require reliance on a foreign government for defense in war and security in peace."

-- Were the trans-Canadian project approved, future expansion of pipeline capacity in order to market additional increments of Alaskan gas would be subject to Canadian regulatory approval, Canadian corporate control, and Canadian political factors.

-- Failure to obtain timely expansion of a trans-Canadian line could adversely affect production of new Alaskan oil discoveries, with which additional natural gas may be associated, including the oil produced in the Naval Petroleum Reserve contiguous to the Prudhoe Bay field.

-- The recently initialled ad referendum agreement with Canada provides no answer to American concerns regarding the foregoing. In addition, it does not provide guarantees against increased provincial ad valorem taxes, etc. As to this latter aspect, the State Department is on record that "the impact of State and Provincial taxes on an Arctic pipeline and other issues relating to a specific pipeline can most effectively be addressed in the context of a protocol negotiated after the approval of the treaty." (Emphasis added.)

I might add that support in Canada for the Foothills and Polar Gas all-Canadian projects to market Canada's arctic reserves raises serious doubts as to whether the Arctic Gas project will gain Canadian approval. Neither Congress nor the Federal Power Commission can assure that the numerous Canadian approvals will be forthcoming within the critical time frame facing this country, if at all. For example, the ruling National Liberal Party adopted a resolution at its November, 1975 convention giving first priority to northern Canadian pipeline schemes that are all Canadian in ownership and which are designed to serve the Canadian public first.

Again, my thanks for this opportunity to contribute to the record of your deliberations. El Paso is at your service should you feel that we can be of help in your consideration of this vital issue of delivering Prudhoe Bay natural gas to the American people as quickly, economically, and securely as possible with an absolute minimum of adverse environmental effects.

Very truly yours,



Enclosures

TESTIMONY OF HOWARD A. SLACK, VICE PRESIDENT
ATLANTIC RICHFIELD COMPANY
BEFORE THE GAS PIPELINE IMPACT COMMITTEE
JUNEAU, ALASKA
FEBRUARY 19, 1976

Mr. Chairman, my name is Howard A. Slack. I am a Vice President of Atlantic Richfield Company and Manager of our North American Producing Division's Alaska Region. I am responsible for Atlantic Richfield's exploration and production activities in the State of Alaska and the adjacent offshore areas.

Atlantic Richfield Company welcomes the opportunity to assist the Committee in its deliberations today. I will address the three topics set forth in your letter of January 30, 1976 - namely, the Rush Moody Report, the State's Reservoir Analysis, and Royalty Gas Options - and I will endeavor to be responsive to the several specific questions raised in your letter.

THE RUSH MOODY REPORT

Mr. Moody's "Legal analysis of issues relating to natural gas transportation" has been studied by Atlantic Richfield's counsel. We do not disagree in any material respect with the principals of

law discussed by Mr. Moody. We do, however, note that Mr. Moody's suggestions concerning State taxation options in his letter to Senator Rader must be read in light of his legal conclusions that taxing schemes that burden interstate commerce or conflict with federal interests are suspect. It should also be noted, that Mr. Moody's legal memorandum and cover letter of January 14, 1976, appear to suggest that the State could, among other things, employ its "as yet unused powers of taxation", including new or increased taxes on producers such as Atlantic Richfield, as a counter to "bargain effectively" with Federal agencies regarding route selection and reservations of gas for State usage. To the extent that Mr. Moody's comments might be construed to advocate such a course of action, we would have contrary views.

As a first step toward a decision concerning natural gas sales, the State should decide whether or not it plans to exercise its option as set forth in its oil and gas leases to take royalty gas in kind and market this production separately from working interest gas. We believe that a prompt decision to permit royalty gas in excess of the State's needs to flow to markets in the South 48 States is essential to both maximize state gas royalty revenues and help insure the viability and early construction of a gas transportation system from the North Slope area. However, to insure that provision will be made for the State's gas needs, we endorse Mr. Moody's view that "the State's power to call upon the gas resource

when needed in the future can, in reasonable probability, be exercised if the State's rights and obligations are fully spelled out, fully presented to the Federal Power Commission (FPC) and accepted by the FPC as an integral part of the transportation system which is certified by the FPC". Once basic agreement has been reached between the State and the FPC, the prospective purchasers of royalty gas can be designated by the State and contracts negotiated which will permit reasonable reservations of gas to meet future Alaskan needs. Atlantic Richfield supports, and believes that Mr. Moody's legal analysis supports, a State policy which would favor:

(1) early construction of a gas transmission system from the North Slope of Alaska to the South 48 States,

(2) the marketing of State royalty gas in the South 48 States coupled with a reasonable reservation of royalty gas volumes to meet future Alaskan needs, and

(3) the adoption of taxation and regulatory policies which would be reasonably calculated to foster such a gas transmission system. To further insure the economic viability of a North Slope gas transmission system, Atlantic Richfield also urges the State to adopt a policy which will include cooperation with Federal regulatory agencies and the oil and gas producing industry to bring about prompt exploration and development of undiscovered Alaskan gas reserves.

In our view, both the national interest and the best interests of the State of Alaska require the earliest possible certification and construction of a viable gas transmission system to permit early gas sales. Design and optimization of such a gas transmission system is dependent upon the proved and potential volume of gas reserves which are estimated to be available for delivery. The State's royalty gas share, even if subject to future Alaskan needs, is a significant factor in determining both economic feasibility and line design. We, therefore, urge an early clarification of the State's intention and a prompt and cooperative resolution of its posture with the FPC. Massive investments will be required to facilitate early gas sales, and we urge the State to adopt and maintain fiscal policies which will facilitate such investments and not handicap an industry already burdened with enormous exploration and development costs.

Atlantic Richfield Company has responded to the Federal Power Commission's interrogatories in connection with the pending FPC proceeding pertaining to transportation of Alaskan natural gas. A copy of the Company's submittal to the FPC is attached to the written copy of my testimony as you have requested.

With regard to the Committee's inquiry pertaining to Atlantic Richfield's commitments for the sale of gas, the company, in accordance with Federal Power Commission Order No. 499, entered into advance payment agreements with Panhandle Eastern Pipeline Company and Texas

Eastern Transmission Corporation committing to each of them a call on 20% of Atlantic Richfield's share of the Prudhoe Bay field gas production. A funding agreement was signed with Pacific Lighting Gas Development Company (PLGD), granting the California company a call on the remaining 60% of Atlantic Richfield's Prudhoe Bay gas. On December 31, 1975, the FPC retroactively terminated the advance payments program for Alaska and the California PUC then scheduled hearings to reconsider its prior approval of the Atlantic Richfield - PLGD funding agreement. As a result of these actions the PLGD funding agreement has been terminated and the advance payment agreements with Panhandle Eastern Pipeline Company and Texas Eastern Transmission Corporation will be terminated if the decision of the FPC becomes final.

While this action on the part of the FPC purports to be in the public interest, in our opinion it is misguided and contra productive where the State of Alaska is concerned in that:

(1) Cancellation of all advance payment agreements will deprive U.S. gas transmission companies and distributors of their former rights to purchase Prudhoe Bay gas and lessen their incentive to invest equity capital in <u>any</u> Alaskan gas transmission facility.

(2) Alaska producers, including the owners of the Prudhoe Bay Field, will be deprived of a source of financing - financing which, in the absence of current Alaskan gas

revenues, is necessary to insure industry capability to find new reserves and develop known reserves at the earliest possible date.

Atlantic Richfield's position as to its gas sale commitments has been clearly set forth in our response to the FPC interrogatories. As we indicated in that response, all of our agreements with prospective purchasers contemplated the ability and willingness of such purchasers to accept deliveries of Prudhoe Bay gas through any gas transmission system which was certificated and constructed. Such an understanding should be an essential ingredient of any other commitment of Prudhoe Bay gas made prior to selection and certification of a gas transmission system. Indeed, both competing route proposals contemplate nationwide delivery capability.

Hence, relative to SCR 66, we can categorically state that our existing commitments to Panhandle Eastern and Texas Eastern are in no way detrimental to the certification of a trans-Alaska natural gas pipeline nor can we conceive of any situation in which we would make a pre-commitment of Prudhoe Bay gas to a market which could not be served by any gas transmission system that might be constructed.

THE STATE'S RESERVOIR ANALYSIS

The Committee has expressed a concern about the effect of the recently published State of Alaska, Department of Natural Resources Study on Sadlerochit Reservoir conservation and specifically whether this study, or the lack of production history, will affect the FPC decision on certification of a gas transmission system. Atlantic Richfield does not believe that the Van Poollen study which was done for the Department of Natural Resources will influence the FPC decision on route selection or certification, nor do we expect it to have any adverse effect upon the financing of the approved gas transmission project. The various points raised in the Van Poollen study had been recognized and incorporated in our studies prior to the time of the Van Poollen report. We have found nothing in the report which will lead us to alter in any way our plans for Prudhoe Bay gas production.

The studies of the Prudhoe Bay Field Sadlerochit Reservoir which have been made by Atlantic Richfield Company and those reported by the state and federal governments differ in a fundamental and important manner. That difference lies in the fact that the various reservoir simulation studies of the Prudhoe Bay Field that have been published were undertaken with different objectives in mind. On the one hand, our studies have as their objective the optimum reservoir management for maximum economic

recovery of oil and gas. On the other hand, we believe the state and federal studies have as their objective the determination of recoveries of either oil or gas for a range of different operating conditions.

The question has been raised concerning the reliability of a model in the absence of production history. It is certainly true that the availability of production history can provide a useful check of a study and a basis for modification. However, Atlantic Richfield has a high degree of confidence in its predictions of Prudhoe Bay reservoir performance. This confidence stems from the fact that in the Prudhoe Bay modeling effort the major elements of the model have been subjected to thorough sensitivity testing. In sensitivity testing the first step is to identify those parameters having the greatest effect on the answer and define those parameters to the fullest extent possible. Our thorough application of this approach and the subsequent follow-up work, both field and laboratory, has given us a high degree of confidence in our current forecast of the Prudhoe Bay Field performance. We are convinced that, although some adjustments may be made to the model as production history is developed, our present studies are adequate to demonstrate that, from a reservoir performance standpoint, early gas sales from the Sadlerochit reservoir would be non-injurious.

As we stated in our response to FPC Question II(5) of the "Interrogatories", Atlantic Richfield believes that the Trans Alaska oil pipeline can be expected to begin operation in Mid-1977 at 600,000 barrels per day, reach a sustained throughput of 1.2 million barrels per day before year's end and have a 1.5 million barrels per day production rate commencing on January 1, 1979. We also believe that at such oil production rates, gas sales of 2.0 to 2.5 billion cubic feet per day would be consistent with good reservoir management.

ROYALTY GAS OPTIONS

We have made no study of the market for State royalty gas inside of Alaska. As to the market for State royalty gas outside of Alaska, in our view the opportunities are virtually unlimited. We are aware that the Department of Natural Resources has solicited offers from potential gas buyers and that many have responded. If the State should decline to separately dispose of its share of the gas, the producers, pursuant to their leases, would be obligated to sell such gas on the same terms that producers' gas would be sold. As noted earlier, prompt State action to resolve the "in kind versus in value" issue and active cooperation with the FPC will expedite early construction of the optimum gas transmission facility.

Thank you again, Mr. Chairman, for affording me the opportunity to testify before your Committee today. Atlantic Richfield's response to your letter of January 15, 1976, is also attached to my statement. If you have any questions concerning my testimony today, I shall be happy to attempt to answer them.

AtlanticRichfieldCompany
North American Producing Division
Alaska Region
Post Office Box 360
Anchorage, Alaska 99501
Telephone 907 277 5637

Howard A. Slack
Vice President &
Resident Manager

February 19, 1976

Senator John Rader, Chairman
Gas Pipeline Impact Committee
Alaska State Legislature
Pouch V
Juneau, Alaska 99811

Dear Senator Rader:

Thank you for your letter of January 15, 1976, and the opportunity to comment on the recently published study entitled "Prediction of Reservoir Fluid Recovery, Sadlerochit Formation, Prudhoe Bay Field" which was prepared by H. K. Van Poollen and Associates for the State of Alaska. The specific questions set out in your letter and our responses are as follows:

QUESTION NUMBER 1

What effect does the recent study, "Prediction of Reservoir Fluid Recovery, Sadlerochit Formation, Prudhoe Bay Field" have on marketing plans for Prudhoe Bay gas?

ANSWER

We do not expect the referenced study prepared by Van Poollen and Associates to have any effect on our plans for marketing Prudhoe Bay gas. The observations reported in this study were recognized and considered in the studies we have prepared with regard to sale of gas from the Prudhoe Bay Field.

QUESTION NUMBER 2

How does this study differ from industry and federal studies?

ANSWER

The state and federal studies differ from Atlantic Richfield's studies primarily because they were undertaken with different objectives in mind. The stated purpose of the Van Poollen

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study prepared for the State of Alaska was to "evaluate the oil recovery potential from the Sadlerochit Reservoir at Prudhoe Bay under a number of different operating conditions." The Aerospace study prepared for the Department of the Interior was designed "to determine estimates for gas reserves and deliverability for a range of reservoir characteristics and operating assumptions." These objectives are much more limited in scope than the objectives of our studies. Over the past five years we have made and are continuing to make reservoir studies oriented toward maximizing economic recovery of both oil and gas reserves. In addition to the broader objectives, our conclusions benefit from the inherent advantages of a more lengthy study time and better analytical resources as well as the fact that we are closer to the source of physical data, and better able to define the key input parameters.

QUESTION NUMBER 3

How accurate can a model be without production history?

ANSWER

In Prudhoe Bay Field, extensive physical data has been gathered on the Sadlerochit Reservoir from well logs, cores, geological studies, laboratory analysis of fluid samples, well tests, etc. These data have been used in preparing mathematical reservoir simulation models. Reservoir performance history associated with field production is very useful in reservoir modeling, but it is not essential. Such data are commonly used to adjust reservoir models so that their calculated performance will match history. As longer periods of performance are compared to the model, confidence in the model's ability to predict future performance is usually increased. However, history matching during the primary stage of production does not necessarily assure a reasonable prediction of secondary recovery performance. Some of the most important parameters in the projection of future performance may not be calibrated during the history match.

Although production history is a valuable source of information for developing reliable reservoir models, sensitivity testing of the model parameters is also important. Without production history, sensitivity testing becomes essential in establishing confidence in the model forecasts. The first step in such testing is to identify those parameters having

the greatest impact on the answer and then concentrate on defining those parameters to the fullest extent possible. We have conducted numerous such sensitivity studies for the Prudhoe Bay Field.

During the past five years, we have made very detailed studies of the Sadlerochit Reservoir for alternative reservoir management programs and we are continuing to make such studies. In view of the extensive physical data available for use in preparing the model and the sensitivity studies that we have made with regard to the key factors influencing reservoir performance, we have a high degree of confidence that the effects of gas production from the Sadlerochit Formation can be predicted with reasonable accuracy.

QUESTION NUMBER 4

Will some production history be necessary before an accurate model is established that will prove feasibility of a gas pipeline for marketing of Sadlerochit gas?

ANSWER

No. As expressed in our answer to question 3, we believe the extensive reservoir data available and the detailed reservoir model studies that have been and are being made based on this data will provide reasonably accurate results that are fully adequate for making decisions with regard to timing and rate of gas sales.

QUESTION NUMBER 5

How critical are the results of this study in obtaining FPC certification and financing for the gas pipeline project?

ANSWER

Conditions leading to the observations made in the Van Poollen study have been recognized and considered by industry in developing plans for marketing of Prudhoe Bay gas. We see no reason for such study to have any impact on the FPC decision on pipeline certification or upon the financing of a gas pipeline project.

I want to thank you for the opportunity to comment on this important study. If you have any additional questions or if we can be of further assistance, please let me know.

Yours very truly,

Howard A. Slack

Howard A. Slack

HAS/jt

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

EL PASO ALASKA COMPANY, ET AL.) Docket No. CP75-96, et al.

ATLANTIC RICHFIELD COMPANY RESPONSES TO INTERROGATORIES

I. POLICY

QUESTION 1. Were you ever a member of a group investigating the feasibility of bringing gas from Prudhoe Bay and/or the Mackenzie Delta to the Lower 48 states?

ANSWER 1. Yes.

QUESTION 1. a. If yes, please describe your participation in the group.

ANSWER 1. a. Atlantic Richfield Company has participated in two such feasibility studies. Atlantic Richfield joined with El Paso Natural Gas Company in a study to determine the economic feasibility of bringing gas from Prudhoe Bay to the West Coast of the United States by means of a trans-Alaska gas pipeline, gas liquefaction and regasification facilities and LNG tankers. Atlantic Richfield contributed its expertise and financial support to this study from April 23, 1973 to October 23, 1974.

Atlantic Richfield has participated in a study to determine the economic feasibility of bringing gas from Prudhoe Bay and the Mackenzie Delta by means of a trans-Canadian pipeline to markets in Canada and the Lower 48 states. Atlantic Richfield contributed its expertise and financial support to this study from July 14, 1970 to November 30, 1975.

QUESTION 1. b. Are you still a member of such a group; and if not, please explain the reasons for departing.

ANSWER 1. b. No. Atlantic Richfield withdrew from these groups since we felt that the purpose for which we had joined, i.e., to determine the feasibility of transporting arctic gas to the Lower 48 states, had been accomplished and that our further participation was unnecessary. We continue to cooperate with both groups.

QUESTION 2. Why haven't firm gas purchase contracts been executed for Prudhoe Bay?

ANSWER 2. As a result of the FPC's Order of December 31, 1975, in Docket R-411, et al., and subsequent action by the California PUC in, sua

sponte, reopening of CPUC decision #84729, Atlantic Richfield's funding agreement with Pacific Lighting Development Company (PLGD), which gave PLGD a call on 60% of its Prudhoe Bay gas, has been terminated. Our advance payment agreements with Texas Eastern Transmission Corporation and Panhandle Eastern Pipeline Company covering the remaining 40% of Atlantic Richfield's Prudhoe Bay gas will be terminated should the FPC Order become final. Under present circumstances we have no basis for negotiation of a definitive gas purchase contract. Neither unit agreements nor a plan of development for the field have been formally submitted to or approved by the State of Alaska.

Additionally, in light of certain language appearing in the Commission's Order of December 31, 1975, in Docket No. R-411, et al., we are uncertain as to whether any gas purchase contract would be certificated or if the Commission would require a full-blown allocation case for North Slope gas.

QUESTION 3. Please explain the relationship of a unitization and operation agreement for Prudhoe Bay to the execution of gas purchase contracts.

ANSWER 3. The Prudhoe Bay Field consists of a gas cap and an oil rim. The field has a diversity of ownerships in the tracts with differing interests in the gas cap and oil rim. Efforts are underway to unitize the entire field so that it might be developed and operated in the most efficient manner. The plan of development agreed to by the producers must then be approved by the State of Alaska. Until such time as these events occur, it is not known what precise amount of gas production and oil production will be owned in the unit by each party nor is it known to what extent and at what time the State will permit gas sales.

QUESTION 4. Do you have any present intention to provide equity for either the El Paso Alaska project or the Arctic-Canadian gas project should either of them be issued a certificate?

ANSWER 4. No.

QUESTION 5. If the natural gas pipeline and distribution companies are unable to commit the amount of equity required by lendors as necessary for either the Arctic Gas or the El Paso project, would your company be willing to help provide some of the needed equity?

ANSWER 5. A decision on the question would be dependent upon conditions at the time such a need becomes apparent; however, it seems highly unlikely that our other capital requirements would permit such an investment.

QUESTION 6. Will your company bear the cost of gathering and treatment facilities on the North Slope? If no decision has been made on this, what factors would influence a decision and by when would such a decision have to be made?

ANSWER 6. The cost of gathering and treatment facilities on the North Slope will be borne in accordance with gas purchase contracts yet to be negotiated. Under our remaining advance payment agreements (which will be terminated in the event the Commission's Order issued December 31, 1975, in Docket No. R-411, et al., becomes final), Atlantic Richfield would bear the initial cost of installing the gas gathering system but would have the option to require the gas purchaser to purchase all gas handling facilities. A decision relative to exercising such option would have been made at the proper time in light of circumstances existing at the time. It was contemplated that the gas conditioning

plant (treatment facilities) would be installed and operated by or for the gas purchasers.

QUESTION 7. Can your company categorically guarantee that the purchase price of Prudhoe Bay gas under future gas purchase contracts would be no higher than the commodity price of gas in the market area to be served adjusted for applicable cost to market?

ANSWER 7. No. So long as the price of natural gas sold for resale in interstate commerce is subject to Federal Power Commission regulation, producers will receive no more than the regulated price permitted at the wellhead. In the event of price decontrol, Atlantic Richfield hopes to receive fair market value at the wellhead for its gas. The commodity price (which is subject to many variables) of gas in any particular market area to be served, adjusted for applicable delivery cost to that market, may or may not have relevance in determining the regulated rate or fair market value at the wellhead.

QUESTION 8. Would your company oppose any attempt by a potential gas purchaser to place a minimum daily delivery volume provision in a gas

purchase contract for the Alaskan North Slope?

ANSWER 8. Yes. We cannot guarantee to deliver any specific volume of gas at any period of time. As mentioned in answer I, 3., the unitization agreement and State action will have a bearing on the volume of gas that can be sold by each company at Prudhoe Bay. As in all oil or gas fields, it is impossible to preduct with certainty what volume of gas will be available from day to day.

QUESTION 9. How did you choose or how will you choose a purchaser or purchasers for your Prudhoe Bay gas? Explain the steps that will be taken or have been taken in this matter.

ANSWER 9. In July, 1974, Atlantic Richfield sent letters to 17 prospective gas purchasers, requesting bids for its share of the natural gas in the Prudhoe Bay Field. With the FPC's Order No. 499 advance payment program in mind, Atlantic Richfield stated that it was interested in offers which include interest-free loans repayable over time as gas is delivered.

Eleven of the 17 companies responded by making offers for Atlantic Richfield's Prudhoe Bay gas. Interstate pipeline companies generally offered to make advance payments

pursuant to Order No. 499 in the form of interest-free loans. Pacific Lighting Gas Development Company (PLGD) offered to make an advance payment for Prudhoe Bay gas, but stated that it was not feasible for PLGD to raise the funds needed to make an interest-free loan. Instead, it offered to make payments to Atlantic Richfield to cover the interest expense and other costs associated with Atlantic Richfield's raising the money through the sale of a production payment.

The offers made by Pacific Lighting Gas Development Company (PLGD), Panhandle Eastern Transmission Corporation and Texas Eastern Pipeline Company, most nearly fulfilled Atlantic Richfield's needs and we proceeded to conclude agreements with them. As noted in the answer to question I (2), the PLGD agreement has been terminated and if the FPC's Order in Docket R-411, et al., becomes final, the remaining advance payment agreements will be terminated. All of these agreements expressly recognize that certification and construction of either of the

proposed Alaskan Gas transmission systems would be satisfactory to both seller and buyer.

In light of the confusion brought about by the Commission's Order in Docket No. R-411, et al., and other uncertainties existing at this time, Atlantic Richfield is in the process of reevaluating all options open to it and has made no decision as to its future action.

II. RESERVES

QUESTION 1. Please describe your exploration and development activities on the North Slope of Alaska through 1975 indicating, among other things, the following:

a. Total amount of acreage held in Prudhoe Bay Field as defined by the Alaska Oil and Gas Conservation Committee;

ANSWER 1. a. Atlantic Richfield Company holds interests in 181,689 gross acres or 94,490 net leasehold acres in the Prudhoe Bay Field as defined by the Alaska Oil and Gas Conservation Committee.

QUESTION 1. b. Number of wells presently drilled in the Prudhoe Bay Field and the success ratio of well completions;

ANSWER 1. b. Fifty-three wells have been drilled on the Atlantic Richfield Company/Exxon Company, U.S.A. acreage in the Prudhoe Bay Oil Pool limits. Six of these wells are not commercial.

QUESTION 1. c. An estimation of the total amount of gas reserves in Prudhoe Bay held by your company and an estimate of its deliverability;

ANSWER 1. c. DeGolyer and MacNaughton, our reserve consultant, has estimated that the proved gas reserves in the Prudhoe Bay Field total 24 Tcf of hydrocarbon gas, with Atlantic Richfield Company's net share calculated to be in excess of 7.08 Tcf. Atlantic Richfield's share of the gas deliverability from Prudhoe Bay Field will depend on the outcome of unitization. Insofar as the total field is concerned, gas production will begin with the start of oil production; but gas sales cannot begin until the gas transportation system is built, gas conditioning facilities constructed and a plan of operation which includes gas

sales is approved by the working interest owners and by the Alaska Oil and Gas Conservation Committee.

QUESTION 1. d. Total amount of acreage held on the North Slope including the offshore area outside of Prudhoe Bay and location of such leases;

ANSWER 1. d. Atlantic Richfield holds interests in 817,734 gross acres or 417,016.41 net leasehold acres on the North Slope of Alaska including the offshore portion and the interest set out in answer II, 1., a., above.

QUESTION 1. e. Number of wells drilled outside of the Prudhoe Bay Field on the North Slope, including offshore areas, their location and an indication whether they were successful; and

ANSWER 1. e. Atlantic Richfield Company has participated in the drilling of 31 wells outside of the Prudhoe Bay Field on the North Slope through 1975. These wells, their location and results are as follows:

ARCO No. 1 Colville, 25-12N-7E, Dry and Abondoned (D and A)

ARCO No. 1 Itkillik, 10-8N-5E, D and A

ARCO No. 2 Kavik, 11-3N-22E, D and A

ARCO No. 3 Kavik, 8-3N-23E, gas

ARCO No. 1 Little Twist, 34-3S-4W, D and A

ARCO No. 1 Nora Federal, 5-2N-14E, D and A

ARCO No. 1 North Franklin Bluffs, 20-8N-14E, D and A

ARCO No. 1 Schrader Unit, 18-3S-5E, D and A

ARCO No. 1 Susie Federal, 22-2N-13E, D and A

ARCO No. 1 Toolik Federal, 4-8N-15E, D and A

ARCO No. 2 Toolik Federal, 5-8N-12E, D and A

ARCO No. 3 Toolik Federal, 4-8N-9E, D and A

ARCO No. 1 Ugnu, 22-12N-9E, oil

ARCO No. 1 West Sak River, 2-11N-10E, oil

ARCO No. 2 West Sak River, 22-11N-10E, oil

ARCO No. 3 West Sak River, 26-11N-9E, oil

ARCO No. 5 West Sak River, 11-10N-10E (confidential)

ARCO No. 6 West Sak River, 29-11N-11E (confidential)

Pan Am Kavik No. 1, 7-3N-23E, gas

BP East Ugnu No. 1, 17-2N-10E, oil

BP East Umiat No. 1, 19-1S-2E, gas

BP Kemik Unit No. 2, 6-1S-21E, D and A

BP Itkillik Unit No. 1, 11-1N-6E, D and A

BP Shale Wall Unit No. 1, 2-5S-5E, D and A

Exxon East Mikkelsen No. 1, 17-9N-21E, D and A

Forest Kemik Unit No. 1, 17-1N-20E, gas

Mobil Beli Unit No. 1, 8-4N-23E, D and A

Mobil Echooka Unit No. 1, 32-1N-16E, D and A

Mobil West Kadleroshilik No. 1, 14-5N-14E, D and A

Texaco East Kuparuk Unit No. 1, 10-2S-8E, D and A

Texaco West Kavik Unit No. 1, 20-5N-20E, D and A

QUESTION 1. f. Total amount of gas reserves estimated to be held on non-Prudhoe Bay field lease and their deliverability.

ANSWER 1. f. DeGolyer and MacNaughton, our reserve consultant, has not assigned any proved reserves on the North Slope outside the Prudhoe Bay Field.

QUESTION (cont'd.) 1. Explain the method and data used in determining any reserve estimates.

ANSWER 1. DeGolyer and MacNaughton has said that "since Prudhoe oil pool is essentially a shut-in field with no reservoir performance data, we have based our reserve estimates on the volumetric method. By volumetric method we mean that we have used individual well data -

logs, cores, fluid samples, and flow tests - to determine the sand thickness in each well and to determine certain average reservoir properties. We then used standard mapping techniques to determine the oil and gas in place throughout the field, including the Atlantic Richfield acreage. Then we have estimated an overall recovery factor based on our experience with other fields of similar reservoir characteristics."

QUESTION 2. Has your company made an independent estimate of the amount of potential reserves on the North Slope of Alaska? If yes, please describe your findings.

ANSWER 2. Yes. Atlantic Richfield has estimated the potential reserves yet to be discovered on the North Slope of Alaska using a method based on recovery factors times the cubic miles of sediment capable of containing hydrocarbons. The area included extends northward from the Brooks Range to the 300 foot water depth at the edge of the Continental platform in the Chukchi and Beaufort Seas. A large part of this area lies under the Polar ice cap. We estimate that recoverable reserves

could range up to 45 billion barrels of oil and 135 Tcf of gas. Estimates of potential reserves derived by this method for untested frontier areas are generally regarded as being optimistic.

QUESTION 3. Based upon your company's drilling experience to date, does it appear that the areal extent of the Prudhoe Bay Field as defined by the Alaska Oil and Gas Conservation Committee is larger than anticipated?

ANSWER 3. No. However, additional wells drilled on either Atlantic Richfield or other companies' acreage may allow the boundary to be moved.

QUESTION 4. Has your company studied the possibility of drilling in the Yukon-Kandik Basin, Middle Tanana Basin and Copper River Basin areas of Alaska? If yes, what do your studies indicate, what has been your past experience in such areas, if any, and what are your company's current and future plans with respect to such areas?

ANSWER 4. Yes, Atlantic Richfield has made evaluations of the Yukon-Kandik, Middle Tanana and Copper River Basins. Atlantic Richfield's experience in these basins has been as follows:

a. Yukon-Kandik Basin

Atlantic Richfield conducted a field program in the basin in 1962. Several areas of interest were found, however, the

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structural fabric was complex and was accompanied with a very limited sedimentary section with good reservoir characteristics.

b. Middle Tanana Basin

No meaningful rocks are exposed in the basin for examination. A well drilled in the basin in 1962 revealed a thin, non-marine tertiary cover.

c. Copper River Basin

Atlantic Richfield drilled two of the eight wells in the Copper River Basin. We did not find significant shows of hydrocarbons in these wells, nor adequate amounts of reservoir quality rock. In addition, the presence of perma-frost and surficial volcanic rocks make it difficult to obtain the quality geophysical data necessary for pinpointing new drill site possibilities.

We have no current plans for additional evaluation of these areas.

QUESTION 5. With respect to oil production from the Prudhoe Bay Field, what are the anticipated deliverability rates for the first 12 years? Will this affect the deliverability of your gas? What effect would a 2.25 Bcf deliverability capacity pipeline have on oil production during this period?

ANSWER 5. The production rate for the early years in the Prudhoe Bay oil field will be limited by the completion, expansion and operation of the Trans-Alaska Oil Pipeline. In later years the oil production rate (as well as gas deliverability) will be determined by field performance. It is not possible to predict with certainty either of these events. Thus, the oil production rates which can be forecast today must be viewed only as reasonable estimates.

The Trans-Alaska Oil Pipeline is expected to begin operation in mid-1977 at 600 thousand barrels per day and reach a sustained throughput of 1.2 million barrels per day before the year's end. As yet, no agreement has been reached on pipeline expansion; however, this expansion could take place by the first of 1979. We have assumed that this expansion will take place as early as possible and have

projected a 1.5 million barrels per day production rate from the Prudhoe Bay Field commencing on January 1, 1979, and continuing until field performance can no longer sustain that rate. The field performance predictions used in this production forecast are based on numerical simulation studies conducted during the past five years. These studies have been conducted for several alternative methods of reservoir management. The studies have also considered the sensitivity to many of the reservoir unknowns. Based on these studies, Atlantic Richfield believes that the following is a reasonable projection for the oil production rate from the Jurassic-Triassic formation and is consistent with 2.0 to 2.5 BCF/D gas sales:

Prudhoe Oil Pool Production[1/] 1977-1988

Year	Rate, MB/D
1977	900[2/]
1978	1,200

(cont'd.)

1/ Production forecast for the Jurassic-Triassic crude oil only, does not include condensate or crude oil from other zones, such as Lisburne or Cretaceous formations.

2/ Average for the last six months of 1977.

(cont'd.)

Year	Rate, MB/D
1979	1,500
1980	1,500
1981	1,500
1982	1,500
1983	1,500
1984	1,500
1985	1,485
1986	1,280
1987	1,020
1988	900

QUESTION 6. Please describe your proposed exploration and development activities for the North Slope, if any, for 1976.

ANSWER 6. A. Exploration

Atlantic Richfield will continue its geological studies on the North Slope during 1976. The Company plans to drill four exploratory wells in search of oil. We have no plans for geophysical work on the North Slope this year.

B. Development

Atlantic Richfield will be drilling development wells with two rigs through-

out 1976. This activity should result in the completion of 20 to 22 wells. In addition, eight to 10 gas injection wells will be drilled and existing wells will be completed and perforated for production.

III. FACILITIES AND COSTS

QUESTION 1. What is the type of gas that will be produced from your Prudhoe Bay leases?

ANSWER 1. Solution gas and gas cap gas will be produced.

QUESTION 2. What type of facilities would be needed to process and/or treat each type of gas?

ANSWER 2. Gas handling and conditioning facilities will be required. The gas handling facilities include the gas compression and treating facilities at the flow stations as well as the gas gathering pipelines, compression facilities, gas injection pipelines and injection wells. The gas conditioning facilities will include equipment to achieve dehydration and removal of excess liquids and carbon dioxide from the gas.

QUESTION 3. Which facilities mentioned in interrogatory 2 will be constructed and operated by the producer and which will be required to be purchased entirely or partly by pipeline purchaser? Who will operate those owned by the pipeline?

ANSWER 3. Our advance payment agreements contemplated that the producer would construct and the gas purchaser would acquire, at Atlantic Richfield's option, those gas handling facilities from the outlet of the oil and gas separators and flash tanks at each flow station or separation center to the gas conditioning plant. No decision was made and no discussions were held as to who would operate these facilities. The gas conditioning plant (at the entrance of the gas pipeline system) would have been constructed and operated at the expense of the gas purchaser or the gas pipeline system.

These agreements have been or will be terminated if the FPC Order becomes final. 3/

QUESTION 4. What is the quality of the gas at the wellhead and what will be the acceptable quality for pipeline delivery?

ANSWER 4. The gas at the wellhead, in addition to containing the basic hydrocarbon constituents, also contains approximately 12% CO_2 and will

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3/ See Answer I, 2.

be saturated with water. Although this gas could be delivered to a pipeline specifically designed to handle this quality of gas, gas purchasers (or transporters) will probably condition the gas to meet such requirements as the gas transportation system may determine.

QUESTION 5. It is noted that certain agreements between various producers on the North Slope and pipeline purchasers reserve the right of the producer to process Prudhoe Bay gas in the Lower 48 states. What type of processing is contemplated by your company, where, when and how much? What type of transportation arrangements would be necessary to implement this provision?

ANSWER 5. At the present time, Atlantic Richfield does not have in mind any specific plans for processing in the Lower 48 states. Any transportation arrangement would have to be made with the gas purchaser and gas transporter and presumably approved by the FPC.

QUESTION 6. What would be the cost of each separate facility mentioned in interrogatory 2 ?

ANSWER 6. The current estimates of costs of the gas handling and conditioning facilities are $1.333 billion and $877 million respectively. It should be noted that it is extremely difficult to estimate these costs at this

time due to the uncertainties of the timing of these facilities and the cost inflation which will occur prior to installation of the facilities.

QUESTION 7. How would you allocate the cost between oil and gas production with the facilities which would be either owned by the pipeline or jointly with your company? Please explain your rationale for such allocation.

ANSWER 7. We do not anticipate the joint ownership by a pipeline company and Atlantic Richfield of any facility handling oil and gas production.[4/] If we were to utilize any facilities owned by the pipeline for such purpose, we would expect to negotiate a charge for such use.

QUESTION 8. If the Prudhoe Bay gas is to be processed through facilities owned by the pipeline or jointly by the producer, who will have benefit of the liquid products and how will the operation and maintenance costs be allocated and on what basis?

ANSWER 8. If your word "processed" is intended to mean conditioned or treated, then under the present argreements[5/] on our Prudhoe Bay gas, Atlantic

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4/ See Answer I, 6.

5/ See Answer I, 2.

Richfield would have the option to take in kind any liquid hydrocarbons incidentally recovered therein. Details were never negotiated but, since it was contemplated that the gas would be sold on a BTU basis the purchaser would have been compensated for the heating value of any liquids extracted and redelivered to the producer.

QUESTION 9. Provide the (a) length and size of the gathering facilities for your operation, (b) estimated cost of such line, (c) ownership of such lines, and for those lines to be owned by the pipeline purchaser or jointly with the producer how will costs be allocated for that portion of the facilities attributable to the transportation of gas?

ANSWER 9. (a) Assuming that your question pertains to natural gas gathering facilities, the natural gas gathering facilities consist of lines connecting the six separation centers to a conditioning facility. These lines are expected to be as follows: 30" diameter, 7 miles; 34" diameter, 5-1/2 miles; 38" diameter, 5-3/4 miles; 42" diameter, 5-1/2 miles. These data are for the entire field.

(b) The cost for these lines is currently estimated to be slightly in excess of

$60 million.

(c) See Answer to I, 6.

QUESTION 10. What type of design would be required for the gas gathering system, i.e., buried, above group pipe, chilling facilities, etc.?

ANSWER 10. The gathering system will be installed on supports above ground and insulated.

QUESTION 11. Would your cost estimates vary depending upon whether the Arctic Gas or El Paso project were certificated?

ANSWER 11. No. We assume that the pipeline delivery specifications, both as to gas quality and pressure, would be identical for either project.

QUESTION 12. What percentage of gas available at the wellhead will be lost in treatment and/or processing?

ANSWER 12. We anticipate that approximately 6% of the hydrocarbon gas could be consumed in conditioning the gas to pipeline requirements. This estimate does not include fuel for operation of the Prudhoe Bay Field.

QUESTION 13. What state approvals will have to be obtained in relation to Alaskan North Slope gas production and when will your company make the necessary filings to obtain such approvals?

ANSWER 13. The lease owners of the Prudhce Bay Field are actively engaged in discussions to

unitize the field. The Prudhoe Bay Field should be unitized prior to commencement of oil production and the agreement must be approved by the Alaska Oil and Gas Conservation Committee. The unitization agreement should contain a plan for the development and operation of the Prudhoe Bay Field, including gas sales timing and volumes, as well as facilities, wells and liquid production rates. The Prudhoe Bay Field owners expect to request approval of these documents during the last half of 1976.

Respectfully submitted,

ATLANTIC RICHFIELD COMPANY

By P. T. Davis ERL
P. T. Davis

AFFIDAVIT

DISTRICT OF COLUMBIA)

EDWARD R. LEAHY, being duly sworn, deposes and says that he is an attorney for Atlantic Richfield Company; that he is authorized to verify and file this document; that he has examined the statements contained in the submittal and that all such statements are true and correct to the best of his knowledge, information and belief.

Edward R. Leahy
EDWARD R. LEAHY

Subscribed and sworn to before me this 13th day of February, 1976.

Sandra M. Pagac
NOTARY PUBLIC

(SEAL) My Commission Expires: August 15, 1977

AGO 545984

Testimony of
Exxon Company, U.S.A.
To
Joint Gas Pipeline Impact Committee
Juneau, Alaska
February 20, 1976

Mr. Chairman, Members of the Joint Gas Pipeline Impact Committee, Mr. Moody. My name is W. Ray Booth, Assistant General Manager of the Natural Gas Department of Exxon Company, U.S.A., P. O. Box 2180, Houston, Texas 77001. I am appearing on behalf of Exxon Company, U.S.A. (A division of Exxon Corporation) pursuant to your letter, Mr. Chairman, dated January 30, 1976 addressed to W. Monte Taylor.

You have requested that Exxon testify with respect to a number of matters contained in the January 30 letter. We have filed separately with the Committee a document containing our full answers thereto. My comments will summarize these answers. The principal questions relate to the State's policy with respect to the sale of royalty gas as discussed in the Rush Moody report, routing of a gas pipeline, and the effect of the gas production on reservoir behavior in the Prudhoe Bay field as reflected in the Van Poollen study.

Rush Moody, Jr. Report

Question 1 of your letter requested comments on the report prepared by Rush Moody, Jr. The legal and policy advice in the report is so extensive that it would not be appropriate to agree or comment fully. Our counsel advises

that he would generally agree with Mr. Moody's legal analysis of the effect of the Natural Gas Act on the shipments of the State's royalty gas in interstate commerce, since once it begins its path in interstate commerce, control thereof will be in the hands of the FPC.

Let me state here at the outset that we have always been aware of the right that the State has preserved in its leases to take its royalty gas in kind. We agree that the State must assess its risks in this matter and act in its best interest. Whether the State takes its royalty gas in kind, or whether it permits its gas to be sold under the producer contracts will not unduly affect Exxon's ability to market its gas.

With respect to the question of "banking" which has been raised in these hearings, we are not opposed to exploring with with state the concepts of a banking arrangement. We would observe that lease owners at Prudhoe Bay will be selling gas to different purchasers and that short term balancing provisions are the norm for the situation where multiple sellers and purchasers exist in the same field. If a balancing concept is extended to include banking of gas for the State on some basis other than for temporary operating purposes, additional operating costs and risks to the banking parties must be considered. Further, some delivery problems could be created for the gas purchasers - i.e., the purchasers would have difficulties in determining their respective future allowable gas takes. Since the lease does not provide for banking, we would have to

consider the State's banking its royalty gas in the light of any specific proposal made by the State.

Mr. Moody indicates the commitment of the state's royalty gas to either of the proposed pipeline projects is of critical significance to their economic viability. The state royalty gas will amount to 250-300 MMcf/d under the 2-2.5 Bcf/d gas production plan. We do not feel that this amount of gas removed from viable systems which are designed for a capacity of 2.4 to 4.5 Bcf/d will affect such viability.

Our counsel advises that he is not in agreement with some other portions of Mr. Moody's letter and particularly the portions which speculate as to the power of the State to take certain actions as lessor which would otherwise be beyond its power as a governing body. I am not sure that this necessarily differs with Mr. Moody's opinion, as he stated affirmatively that he does not offer an unqualified opinion that such legislation would withstand court challenge. From Exxon's point of view, the state has leased certain lands for a valuable consideration. There are equities to the lessees that should be considered, and the State should not continue to reduce the value of what it has leased, appropriating those values to itself.

FPC Interrogatories

We have supplied a copy of Exxon Company, U.S.A.'s answers to the FPC interrogatories which were requested and

believe them to be self-explanatory. These answers generally reflect information which has previously been provided to various Alaska State agencies.

Commitments for Sale of Prudhoe Gas

Regarding commitments for the sale of Prudhoe gas, Exxon Corporation, as of February 27, 1976, will have no agreements with any potential purchaser for its share of Prudhoe Bay gas reserves. Prior agreements between Exxon and potential purchasers providing for negotiating rights in exchange for advance payments have been terminated by mutual agreement of the parties due to the action of the Federal Power Commission on December 31, 1975, which eliminated, retroactively, rate base treatment for advances made by these pipelines for Alaskan gas reserves.

Senate Concurrent Resolution 66

With regard to Senate concurrent resolution 66, we can fully understand why many people in Alaska feel it is to the best interest of the State to have a gas pipeline built through Alaska rather than principally through Canada. However, our involvement in the implementation of this resolution gives us some concern. First, Exxon Company, U.S.A. is not engaged in the transportation of natural gas in interstate commerce, nor does it intend to invest in either one of the competing gas pipeline proposals. Exxon Company, U.S.A. intends to sell its gas in the field as a conventional producer

sale. As a seller of gas in the field, Exxon cannot legally commit its purchasers as a condition of sale to transport the gas over a designated route. Our recently terminated agreements with prospective purchasers included a provision recognizing the right of the prospective purchaser to enter into any transportation arrangement suitable to it.

Second, we have in mind the fundamental principal of gas economics that where transportation costs are minimized, the wellhead value is more likely to approach its consumer price. Based on information filed with the FPC the transportation costs of gas from the North Slope to markets in the lower 48 states are less when transported by pipeline through Canada than through Alaska by pipeline and then by tanker as LNG. Such lower transportation costs could benefit the Prudhoe Bay gas owners, including the State of Alaska.

We recognize that there are other counter-balancing factors which the State of Alaska may consider, the primary one being that the trans-Alaska route of the pipeline would make the gas more available to Alaska markets should these markets later develop. On the other hand, if the State would adopt an orderly schedule of oil and gas development and maintain a stable investment climate, gas for later developing markets could be available.

From a practical standpoint, however, it must be recognized that the final decision on the gas pipeline certifica-

tion will be made by the FPC, or perhaps even the U.S. Congress. If available information indicates that the Alaska route is in the national interest, giving full consideration to construction costs and environmental impact, then it may be expected that the Alaska route will be certified. In any event, all of the factors which Alaska deems to be of importance in developing the best route will no doubt be presented so that the proper decision will be made. Therefore, it is not proper for Exxon to make commitments in support of a trans-Alaska natural gas pipeline routing, or for that matter, for any particular routing.

Sadlerochit Reservoir Study

Question 1(a) refers to questions in Senator Rader's letter of January 15, 1976. Exxon's answers to these questions on the Van Poolen study are contained in Exhibit "B" to the written response which has been submitted to you. Please note that our answers are based only on a preliminary review of the report prepared by Van Poollen. We expect that when economics of the total field production are considered the results of the Van Poollen study will be consistent with other studies which indicate that the optimum producing plan for the Prudhoe Bay field will involve gas deliveries of 2 to 2.5 Bcf/d beginning as soon as a gas pipeline is available. Aou are aware that the field working interest owners advised the Division of Oil and Gas that they plan a technical review of the field operating plans in July of this year, at which

time the Van Poollen reservoir study can be discussed in more detail.

Royalty Gas Options

Prospective Purchasers for State Royalty Gas - In Exxon's opinion, the prospective purchasers of the State of Alaska's royalty gas are the same firms which are prospective purchasers of portions of Exxon's share of the gas. Most of the large gas transmission and distribution companies with markets in the lower 48 states have demonstrated substantial interest in purchasing some Prudhoe Bay gas.

Household or Industrial Use Within Alaska - Exxon has no detailed independent study relative to the possibilities of household or industrial use of natural gas within Alaska. We are aware of Mr. Ward's report of the Arctic Gas study of prospective Fairbanks area gas demand, prepared about two years ago. That study concluded that substantial use of natural gas in Fairbanks was unlikely even if gas were available.

Conclusion

In conclusion, I would refer you to the testimony of Judd Miller, Jr. presented to this Committee on December 10, 1975 on behalf of Exxon Company, U.S.A. We reiterate that the State's interest and the interest of the leaseholders are generally the same. An optimum producing plan for the Prudhoe field will provide maximum economic benefits for all con-

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cerned. This will include producing the large gas reserves simultaneously with the oil after a minimum delay of only 3-5 years as required for pipeline approval and construction. These conclusions appear to be supported by the Van Poollen study. Not only does a gas pipeline provide an opportunity to produce gas from Prudhoe Bay, it will also provide the opportunity to sell gas from other fields. This will enhance the overall attractiveness of future exploration in Alaska and increase the value of the State's acreage. Finally, I would like to emphasize the importance associated with the support of all concerned parties and the early approval and construction of a gas pipeline from the Arctic Slope.

EXXON COMPANY, U.S.A.
POST OFFICE BOX 2180 · HOUSTON, TEXAS 77001

NATURAL GAS DEPARTMENT

W. RAY BOOTH
ASSISTANT GENERAL MANAGER

February 18, 1976

Joint Gas Pipeline Impact Committee
Alaska State Legislature
425 G Street, Suite 750
Pouch V
Juneau, Alaska 99801

Attention: Senator John H. Rader, Chairman

Gentlemen:

There are enclosed for the Committee's information, the response of Exxon Company, U.S.A. to the questions submitted with your letter of January 30, 1976 to Mr. W. Monte Taylor of this company.

I plan to make a statement on behalf of our company during the hearing on February 19, 1976 in Juneau.

Very truly yours,

W. Ray Booth
Assistant General Manager
Natural Gas Department

WRB/bl
Enclosures

A DIVISION OF EXXON CORPORATION

Questions Relating to Topics
To Be Discussed At Hearings of
The State of Alaska Legislative
Gas Pipeline Impact Committee
On February 17-18-19, 1976

Q.1. The Committee solicits your review and comments on the report prepared by Rush Moody, Jr.

a) Are you in agreement with Mr. Moody's legal analysis?

A.1.(a) We are in agreement with a part of Mr. Moody's analysis and in disagreement with other parts as we will briefly comment on in answer to question 1.(b).

Q.1. b) How should this analysis effect state policy with regards to royalty gas, taxation, or state leasing powers?

A.1. b) With respect to state royalty gas, our counsel advises that in general he would agree with Mr. Moody's analysis of the effect of the Natural Gas Act on the shipments of the state's royalty gas in interstate commerce and that, therefore, the state should decide what it proposes to do with its royalty gas, since once it begins its path in interstate commerce, control thereof will be in the hands of the FPC.

With respect to state policy concerning taxation, it is understood that this subject will be considered in extensive legislative hearings in connection with particular statutes that have been introduced. Further, concerning state leasing powers, our counsel advises that he cannot agree with Mr. Moody; this subject has been before this legislature on numerous occasions and has been the subject of extensive litigation in this State. Therefore we have no comment upon either of these topics.

Q.1. c) Could you please supply the Committee with the answers to the FPC "Interrogatories"?

A.1. c) The answers to the FPC "Interrogatories" are attached as Exhibit "A" hereto, entitled "Response Of Exxon Corporation To FPC Interrogatories Dated December 12, 1975, El Paso Alaska Company, et al., Docket No. CP75-96, et al."

Q.1. d) If you are or plan to be a gas producer, what commitments have you made for sale of gas? Are you prepared to support the State's efforts relative to SCR 66?

A.1. d) Regarding commitments, Exxon Corporation, as of February 27, 1976, will have no effective agreements with any potential purchaser for its share of Prudhoe Bay gas reserves. Prior agreements between Exxon and potential purchasers providing for negotiating rights in exchange for advance payments have been terminated by mutual agreement of the parties due to the action of the Federal Power Commission on December 31, 1975 which eliminated rate base treatment retroactively for advances made by these pipelines for Alaskan gas reserves.

Regarding SCR 66, Exxon expects to sell its North Slope gas at the well or in the field. This would be in conformity with usual practice in the United States.

Because of legal and regulatory restraints, a seller may not control transportation modes of any commodity, including natural gas, after delivery, or attempt to control transportation methods as a condition of sale. The public interest is best served when buyers and sellers compete unfettered by ancillary restraints as to transportation mode. The buyer must be free to choose the transportation mode for the commodity he has purchased. Neither producing nor gas purchasing companies will select the pipeline route. The Federal Power Commission has been holding extensive hearings on the competitive routes. Exxon believes the transportation mode will be chosen not on the basis of which companies have signed gas purchase contracts, but on the determination of the most practical and efficient mode.

Q.2. Testimony regarding the Sadelrochit Reservoir study recently completed by the Department of Natural Resources:

a) Reference questions in letter of January 15.

A.2. a) Our responses are enclosed as Exhibit "B" hereto, entitled "Response of Exxon Company, U.S.A. to Questions Posed By Senator John H. Rader By Letter Dated January 15, 1976".

Q.2. b) Reference FPC "Interrogatories", Part II.

A.2. b) The answers to FPC "Interrogatories", Part II are included in Exhibit "A".

Q.3. Royalty Gas Options

a) What prospective purchasers exist for state royalty gas, inside or outside of Alaska?

b) What is the possibility of household or industrial use of natural gas within Alaska?

A.3. Royalty Gas Options

a) Prospective Purchasers for State Royalty Gas

In Exxon's opinion, the prospective purchasers of the State of Alaska's royalty gas are the same firms which are prospective purchasers of portions of Exxon's share of the gas. Most of the large gas transmission and distribution companies with markets in the lower 48 states have demonstrated substantial interest in purchasing some Prudhoe Bay gas. So far, however, potential purchasers with markets inside Alaska have failed to express interest to Exxon.

b) Household or Industrial Use Within Alaska

Exxon has no independent detailed study relative to the possibilities of household or industrial use of natural gas within Alaska. The most recent study within Exxon's knowledge is an Arctic Gas study of prospective Fairbanks area gas demand, prepared about two years ago. That study concluded that substantial use of natural gas in Fairbanks was unlikely even if gas were available. No doubt, similar studies have been made of the possibilities of increased natural gas utilization in South Alaska.

Possibly useful information regarding the prospects for such gas usage would be found in the responses received to last year's solicitations of interest by the Alaska Royalty Oil and Gas Development Advisory Board.

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EXHIBIT "A"

TO

RESPONSE OF EXXON COMPANY, U.S.A.

STATE OF ALASKA

LEGISLATIVE GAS PIPELINE IMPACT COMMITTEE

February 17-18-19, 1976

EXXON COMPANY, U.S.A.
POST OFFICE BOX 2180 · HOUSTON, TEXAS 77001

PAUL W. WRIGHT
COUNSEL

February 13, 1976

OGC
El Paso Alaska Company, et al.
Docket No. CP75-96, et al.

Interrogatories

Mr. Kenneth F. Plumb, Secretary
Federal Power Commission
825 N. Capitol St N.W.
Washington DC 20426

Dear Sir:

By letter dated December 12, 1975, Commission Staff Counsel Allan W. Anderson, Jr. transmitted to Exxon Corporation a series of written interrogatories in connection with the above-referenced proceeding.

Attached hereto for filing are the original and three conformed copies of the "Response of Exxon Corporation To FPC Interrogatories Dated December 12, 1975". Please direct any inquiries with respect to this Response to one of the following:

Martin N. Erck
Paul W. Wright
Larry W. Lindeen
Exxon Corporation
PO Box 2180
Houston TX 77001
AC713 656-4705

Copies of this filing have been served upon all parties to the restricted service list compiled in this proceeding in accordance with Commission regulations. Please acknowledge receipt of this document by placing your file mark on the enclosed extra copy and return same to the undersigned in the enclosed self-addressed envelope.

Very truly yours,

Paul W. Wright

PWW/bl
Attachments

cc: Hon. Nahum Litt
Presiding Adm. Law Judge

Allan W. Anderson, Jr., Esq.
Commission Staff Counsel

RESPONSE OF

EXXON CORPORATION

TO FPC INTERROGATORIES
DATED DECEMBER 12, 1975

El Paso Alaska Company, et al.

Docket No. CP75-96, et al.

February 13, 1976

I. POLICY

Q.1. Were you ever a member of a group investigating the feasibility of bringing gas from Prudhoe Bay and/or the Mackenzie Delta to the lower forty-eight states?

A.1. Yes.

Q.1.a. If yes, please describe your participation in the group.

A.1.a. Exxon Company, U.S.A., (a division of Exxon Corporation) was one of the six initial participants in the Northwest Project Study Group. Exxon continued its participation from June, 1970 through the merger with the Gas Arctic Study Group in 1972 and numerous additions to the membership of the Gas Arctic-Northwest Project Study Group (Arctic Gas), while feasibility studies were in progress.

Q.1.b. Are you still a member of such a group; and if not, please explain the reasons for departing.

A.1.b. Exxon Company, U.S.A. withdrew as a participant in Arctic Gas in January, 1975. Our public announcement at that time was as follows:

> "Exxon, USA joined a predecessor study group in 1970 because it was interested in the development of a project that would be capable of moving Prudhoe Bay gas to market. The company believes these initial project development objectives have been accomplished.
>
> "Exxon, USA is not in the interstate gas transmission business. The company has decided to withdraw from the study group now that the Arctic gas pipeline project is nearing an implementation stage."

Q.2. Why haven't firm gas purchase contracts been executed for your Prudhoe Bay gas?

A.2. As explained by Exxon Counsel on the record in this proceeding on several occasions and in the "Response Of Exxon Corporation To Oral Motions To Certify" dated December 15, 1975, definitive gas purchase contracts must await a decision on the competitive aspects of the two transportation proposals before the Commission and the completion (and approval by the State of Alaska) of a unitization agreement and operating plan for the Prudhoe Bay field by the working interest owners of

the field.

Q.3. Please explain the relationship of a unitization and operation agreement for Prudhoe Bay to the execution of gas purchase contracts.

A.3. We anticipate that the Prudhoe Bay field will be unitized prior to initiation of oil production scheduled for mid-1977. The Prudhoe Bay Unitization and Operating Agreements will provide among other things for the allocation of oil and gas production between owners of leases in the field. Upon unitization Exxon will own an agreed upon percentage share of gas produced in the field whether such gas is produced from the gas cap, from the oil zone, from an Exxon interest lease or from a lease in which Exxon has no current interest. Until such agreements have been executed by the working interest owners and the unit plan is approved by the State of Alaska, there exists uncertainty as to both Exxon's share and the total quantity of the gas available for sale. For these reasons, the execution of a gas purchase contract prior to unitization would be premature.

Q.4. Do you have any present intention to provide equity for either the El Paso Alaska project or the Arctic-Canadian gas project should either of them be issued a certificate?

A.4. There is no intention for Exxon Company, U.S.A. (a division of Exxon Corporation) to provide equity for either project. Imperial Oil Ltd. in which Exxon Corporation has approximately a 70% interest, is a member of the Arctic Gas consortium and has made a tentative equity commitment.

Q.5. If the natural gas pipeline and distribution companies are unable to commit the amount of equity required by lenders as necessary for either the Arctic gas or El Paso project, would your company be willing to help provide some of the needed equity?

A.5. Only as noted in response to interrogatory 4.

Q.6. Will your company bear the cost of gathering and treatment facilities on the North Slope. If no decision has been made on this, what factors would influence any decision and by when would such a decision have to be made?

A.6. Exxon plans to sell its gas in the field and thus plans that the purchaser(s) of its gas will own those facilities required for handling, gathering and treating the gas to pipeline quality specifications downstream of field separation facilities. Exxon expects to have the right to use a portion of these facilities subject possibly to Exxon paying a charge for such usage during periods of required gas injection.

Q.7. Can your company categorically guarantee that the purchase price of Prudhoe Bay gas under future gas purchase contracts would be no higher than the commodity price of gas in the market area to be served adjusted for applicable costs to market?

A.7. No.

Q.8. Would your company oppose any attempt by a potential gas purchaser to place a minimum daily delivery volume provision in a gas purchase contract for the Alaskan North Slope?

A.8. Yes, Exxon certainly would oppose any attempt by a potential gas purchaser (or the Commission, for that matter) to impose minimum daily delivery volume provisions. The several valid reasons for this position have been stated in the following documents which are in the public files of the Commission and which are incorporated herein by reference:

1. Application For Rehearing And Motion For Reconsideration, filed by indicated producers, Docket No. RM76-8, dated November 11, 1975.

2. Motion For Oral Argument, Docket No. RM76-8, dated December 19, 1975.

3. Application Of Exxon Corporation For Rehearing, Docket No. CI74-528, dated December 3, 1975.

Q.9. How did you choose or how will you choose a purchaser or purchasers for your Prudhoe Bay gas? Explain the steps that will be taken or have been taken in this matter.

A.9. Exxon independently will choose the party or parties with whom it will negotiate gas sales contract(s) utilizing criteria which are proprietary to it. Exxon's marketing strategy is completely confidential, recognizing however that under present law sales in

interstate commerce for resale must be the subject of Certificates of Public Convenience and Necessity issued by the Commission.

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II. RESERVES

Q.1. Please describe your exploration and development activities on the North Slope of Alaska through 1975 indicating among other things the following:

Q.1.a. total amount of acreage held in Prudhoe Bay field as defined by the Alaska Oil and Gas Conservation Committee;

A.1.a. The Prudhoe Bay Oil Pool limits shown on the attached map are taken from the Alaska Division of Oil and Gas Report dated June, 1974 entitled "In Place Volumetric Determination of Reservoir Fluids Sadlerochit Formation Prudhoe Bay Field". Exxon holds leases on 70,756 net acres within these geographic limits. That acreage shown as Exxon-ARCO is owned on a 50-50 basis with the Atlantic Richfield Company.

Q.1.b. number of wells presently drilled in the Prudhoe Bay field and the success ratio of well completions;

A.1.b. A total of 53 wells have been drilled on Exxon interest acreage within the limits of the Prudhoe Bay Oil Pool, of which 47 were successful, five were dry, and one suspended (as defined in the answer to 1.e.).

Q.1.c. an estimation of the total amount of gas reserves in Prudhoe Bay held by your company and an estimate of its deliverability.

A.1.c. Based on current estimates, Exxon's share of proved Prudhoe Oil Pool gas reserves is 8.7 Tscf.

Based on Exxon's operational, economic and reservoir studies, we believe the optimum producing plan will include the production (when sales commence, currently estimated to be 3 to 5 years after the start of oil production) of an amount of gas sufficient to allow the purchaser(s) to deliver 2 to 2.5 Bcf/day of pipeline quality gas to a gas pipeline. Exxon's working interest share of gas deliveries to purchaser(s) is expected to be in the range of 0.7 Bcf/day and 0.95 Bcf/day.

Q.1.d. total amount of acreage held on the North Slope including the offshore area outside of Prudhoe Bay and location of such leases;

A.1.d. Exxon currently holds 167,425 net acres. The location of these leases is shown on the attached map.

Q.1.e. number of wells drilled outside of the Prudhoe Bay field on the North Slope including offshore areas, their location and an indication whether they were successful;

A.1.e. Exxon has participated, on a working interest basis, in eleven wells on the North Slope outside of the Prudhoe Oil Pool Limits. The location of these wells and their status are shown on the attached map. Additional information regarding the status of these wells is included on the attached tabulation. Exxon has participated in three wells classified as suspended. The classification of suspended applies to those wells adjacent to unleased acreage. To maintain the competitive nature of exploration, information on such wells is not released pending the disposition of adjacent acreage.

Q.1.f. total amount of gas reserves estimated to be held on non-Prudhoe Bay field leases and their deliverability.

A.1.f. Of the wells not classified as "suspended", seven were dry holes and one (the Kemik Unit #1) is a marginal gas discovery. This discovery will require further drilling before any determination of either reserves or deliverability is possible.

Q.2. Has your company made an independent estimate of the amount of potential reserves on the North Slope of Alaska? If yes, please describe your findings.

A.2. The USGS estimates* of undiscovered gas resources on the North Slope range from 14 to 49 Tcf, with a statistical mean of 28 Tcf. Exxon feels these estimates establish a good base for further analyses by the FPC. Equally important as the amount of potential reserves are such factors as the timing of discovery and development, the size and location of fields found, plus when and at what rate the gas can be transported to market.

Q.3. Based upon your company's drilling experience to date, does it appear that the areal limit of the Prudhoe Bay field as defined by the Alaska Oil and Gas Conservation Committee is larger than anticipated?

A.3. No.

Q.4. Has your company studied the possibility of drilling

*Geological Survey Circular 725

in the Yukon-Kandix Basin, Middle Tanana Basin and Copper River Basin areas of Alaska? If yes, what do your studies indicate, what has been your past experience in such areas, if any, and what are your company's current and future plans with respect to such areas?

A.4. Exxon has conducted exploration studies in the Yukon-Kandix, Middle Tanana and Copper River basins and at one time did hold several leases or lease applications. Exploration data developed did not provide sufficient encouragement for additional exploratory effort and the leases were cancelled. Exxon has no immediate plans for lease acquisitions or drilling in these three basins.

Q.5. With respect to oil production from the Prudhoe Bay field, (a) what are the anticipated deliverability rates for the first twelve years? (b) will this affect the deliverability of your gas? (c) what effect would a 2.25 billion cubic feet deliverability capacity pipeline have on oil production during this period?

A.5.(a) It is not possible to make precise forecasts of future oil production, especially for such a long period into the future, but the following represents our best current estimate of crude oil production from the Prudhoe Bay field.

The Trans Alaska Pipeline is expected to begin operation in mid-1977 and sustained throughput of 1.2 million barrels of oil per day should be achieved by January 1, 1978. Although decisions on future expansions of the pipeline have not been firmly established at this time, the Prudhoe Bay Field is expected to produce 1.5 million barrels of oil per day by January 1, 1979, and it is anticipated that the pipeline will be expanded accordingly. If an early expansion to 1.5 million barrels per day is accomplished, a rate decline during the latter part of the first twelve years of operation would be expected, unless reserves are substantially in excess of those currently recognized.

A.5.(b) No.

A.5.(c) None, based on current studies.

Q.6. Please describe your proposed exploration and development activities for the North Slope, if any, for 1976.

A.6. Exxon is continuing its geological and geophysical studies for the North Slope and is contemplating seismic programs during the winter and summer of 1976. Exxon does not plan to drill any wells during 1976 on Exxon operated acreage.

Planned development activity jointly with ARCO within the Prudhoe Oil Pool Limits in 1976 is expected to consist of the continued development drilling of approximately 30 wells and the continuation of the installation of field facilities associated with anticipated oil production startup by mid-1977.

III. FACILITIES AND COSTS

Q.1. What is the type of gas that will be produced from your Prudhoe Bay leases?

A.1. The natural gas produced at Prudhoe Bay will be associated with oil production and will consist of a mixture of solution gas evolved from oil and gas from the gas cap.

Q.2. What type of facilities would be needed to process and/or treat each type of gas?

A.2. Processing of Prudhoe Bay gas will not be required, although it may be found to be economic, as discussed in 5. below. Treatment of the gas, however, will be required. Based on current planning, the facilities required to handle the produced gas from the gas-oil separators to the inlet of the gas pipeline are:

(a) Gas Facilities At Gas-Oil Separation Centers

Compression for low pressure gas and conditioning to make the gas suitable for gathering from the gas-oil separation centers to the central location. This conditioning will include cooling and dehydration for hydrocarbon and water dew point control.

(b) Gas Gathering Facilities

Gas gathering lines to gather the gas from the gas-oil separation centers to a central location in the field.

(c) Gas Conditioning Plant Facilities

Gas conditioning to bring the gas to pipeline quality including carbon dioxide removal, hydrocarbon dew point control, dehydration, and compression and cooling to pipeline pressure and temperature.

Q.3. Which facilities mentioned in interrogatory 2 would be constructed and operated by the producer and which will be required to be purchased entirely or partly by a pipeline purchaser? Who will operate those owned by the pipeline?

A.3. See response to question I.6. Exxon intends to act as the purchaser's representative in the construction and operation of those facilities.

Q.4. What is the quality of the gas at the wellhead and what will be the acceptable quality for pipeline delivery?

A.4. The gas will not be available at the wellhead since it will be mixed with oil and condensate. It will be delivered to the purchaser after separation from the oil and condensate. It is anticipated that the separation will be done in three stages which during initial production of the field will be approximately 650 psig and 170° F. for the first stage, 80 psig and 150° F. for the second stage, and a slight positive pressure (approximately 0.5 psig) and 150° F. for the third stage. Based on our current engineering calculations, the estimated composition and quality of the combined gases from all three stages of separation are as follows:

Composition, Mol Percent	
Methane	72.92
Ethane	6.91
Propane	3.72
Iso Butane	0.58
Normal Butane	1.23
Pentanes plus	1.42
Carbon Dioxide	12.71
Nitrogen	0.51
Total	100.00
Heating Value (Gross, Wet, Actual @ 14.73 psia and 60° F.), Btu/cu.ft.	1063
Water Content, Lbs/MMcf	820
H_2S Content, grs./100 cu.ft.	*

*Not precisely known at this time, but is less than 1 grain per 100 cubic feet.

The low pressure portions of the above gas stream will be compressed to about 650 psig and the combined stream, cooled, dehydrated, and reheated before delivery into the field gas gathering system at approximately 620 psig and 100° F. After this treatment, the gas is expected to have the following composition and quality:

Composition, Mol Percent	
Methane	73.34
Ethane	6.91
Propane	3.67
Iso Butane	0.56
Normal Butane	1.18
Pentanes plus	1.08
Carbon Dioxide	12.74
Nitrogen	0.52
Total	100.00
Heating Value (Gross, Wet, Actual @ 14.73 psia and 60° F.), Btu/cu.ft.	1046
Water Content, Lbs/MMcf	1 (approx.)
H_2S Content, grs./100 cu.ft.	*

*Not precisely known at this time, but is less than 1 grain per 100 cubic feet.

It is Exxon's opinion that the Prudhoe Bay gas composition and quality used by Arctic Gas in the design of their pipeline facilities will be suitable for transmission through the pipeline (or any other pipeline operating at the same pressure [1680 psig] and temperature [less than 30° F.] conditions). The composition was furnished to Arctic Gas by the Prudhoe Bay producers and is our best current engineering estimate of the quality of the gas after treatment to make it suitable for pipeline operations, pending detail design of the gas treating facilities. The treated gas composition is recorded on page 12 of Section 8.b.2. of the Arctic Gas filing and is shown below for comparison with the above compositions along with Exxon's estimates of other characteristics which describe the gas "quality":

Composition, Mol Percent	
Methane	85.11
Ethane	7.70
Propane	3.99
Iso Butane	0.50
Normal Butane	0.73
Pentane plus	0.22
Carbon Dioxide	1.00
Nitrogen	0.75
Total	100.00
Heating Value (Gross, Wet, Actual @ 14.73 psia and 60° F.), Btu/cu.ft.	1130
Water Content, Lbs/MMcf	0.2**
H_2S Content, grs./100 cu.ft.	*

*Not precisely known at this time, but is less than 1 grain per 100 cubic feet.

**Tentative, pending results of research work in progress to determine whether a water content this low will actually be required.

Q.5. It is noted that certain agreements between various producers on the North Slope and pipeline purchasers reserve the right of the producer to process Prudhoe Bay gas in the lower forty-eight states. What type of processing is contemplated by your company, where, when and how much? What type of transportation arrangements would be necessary to implement this provision?

A.5. Exxon plans to reserve the right to process its Prudhoe Bay gas. An adequate evaluation of an operation to exercise such a right is not possible at this time, because of many uncertainties, such as the location of the gas transportation facilities. This will probably not be possible prior to the early 1980's, at which time it should be possible to define clearly and negotiate, if appropriate, the type of arrangement which would be mutually satisfactory to the parties involved.

Q.6. What would be the cost of each separate facility mentioned in interrogatory #2?

A.6. Estimated costs of the facilities are as follows:

Facility	Estimated Cost, $MM 7/1/75 Basis	Escalated Basis
Gas Facilities at Gas-Oil Separation Centers	527	634
(including IDC of)	(98)	(118)
Gas Gathering Facilities	57	63
(including IDC of)	(8)	(8)
Gas Conditioning Plant Facilities	1252	1590
(including IDC of)	(286)	(360)
TOTAL	1836	2287
(including IDC of)	(392)	(486)

Q.7. How would you allocate the costs between oil and gas production for the facilities which would be either owned by the pipeline or jointly with your company. Please explain your rationale for such allocation.

A.7. We do not envision that an allocation of costs will be necessary. All the facilities enumerated in III.A.2. and A.6. will be required for the handling, gathering and conditioning of the gas by the purchaser prior to delivery to a gas pipeline.

Q.8. If the Prudhoe Bay gas is to be processed, through facilities owned by the pipeline or jointly by the producer, who will have benefit of the liquid products and how will the operation and maintenance costs be allocated and on what basis?

A.8. The removal of hydrocarbon liquids which will be required at Prudhoe Bay will be a treating, not a processing, operation. Excess liquid hydrocarbons removed in treating will not be sold to the gas purchaser(s). Although firm plans have yet to be made concerning disposition of these liquids, Exxon expects that they will either be used as fuel or transported in the oil pipeline. Exxon expects to bear the costs, if any, to store and transport its

share of these liquids. If processing should be found to be economic, it would be conducted under arrangements yet to be negotiated.

Q.9. Provide the (a) length and size of the gathering facilities for your operations (b) estimated costs of such lines (c) ownership of such lines, and for those lines to be owned by the pipeline purchaser or jointly with the producer how will costs be allocated for that portion of the facilities attributable to the transportation of gas?

A.9. (a) The gas will be gathered from the six gas-oil separation centers to the central gas conditioning plant in the following lines:

Diameter, inches	Length, miles
30	7.0
34	5.6
38	5.7
42	5.4

(b) See cost estimate table in response to III.6.

(c) Exxon's plans are that the portion of these facilities which is necessary for gathering Exxon's gas will be owned by the purchaser(s) of its gas. The matter of allocation is dealt with in the response to III.7.

Q.10. What type of design will be required for the gathering system, i.e. buried, above ground pipe, chilling facilities, etc.?

A.10. The pipelines will be insulated and will be laid above ground on supports.

Q.11. Would your costs estimates vary depending upon whether the Arctic gas or El Paso project was certificated?

A.11. No, assuming pipeline quality and pressure specifications are the same.

Q.12. What percentage of the gas available at the wellhead will be lost in treatment and/or processing?

A.12. Of the gas available for sale at the separator outlets, approximately 12% will be removed as

carbon dioxide and approximately 6% will be consumed as fuel. The gas available for sale at the separator outlets does not include field fuel requirements.

Q.13. What state approvals will have to be obtained in relation to Alaskan North Slope gas production and when will your company make the necessary filings to obtain such approval?

A.13. The Prudhoe Bay Field Working Interest Owners plan to unitize the field prior to initiation of oil production. The Alaska Department of Natural Resources must approve this unitization plan. Associated with this approval will be approval of a unit operating plan including a plan for gas sales.

Negotiations are underway by the Prudhoe Bay Working Interest Owners and the request for State approvals will be made as soon as possible.

EXXON COMPANY, U.S.A. WORKING INTEREST WELLS DRILLED ON NORTH SLOPE

OUTSIDE OF THE PRUDHOE OIL POOL LIMITS

EXXON OPERATED

Map Code	Well Name	Completion Date	Status
1	E. Mikkelsen Bay State #1	6/16/71	D & A
2	Canning River Unit A #1	7/10/74	D & A
3	Canning River Unit B #1	4/22/75	D & A
4	Alaska State A #1	9/21/75	Suspended

OTHER OPERATED

Map Code	Operator	Well Name	Completion Date	Status
5	Atlantic Richfield	Delta State #1	2/27/69	D & A
6	Atlantic Richfield	Toolik Federal #2	9/14/69	D & A
7	Atlantic Richfield	Toolik Federal #1	4/15/69	D & A
8	Atlantic Richfield	Susie Unit #1	1/9/67	D & A
9	Forest	Kemik Unit #1	6/17/72	Shut-in gas well
10	Atlantic Richfield	Delta State #2	5/17/75	Suspended
11	Atlantic Richfield	West Sak River #5	2/27/75	Suspended

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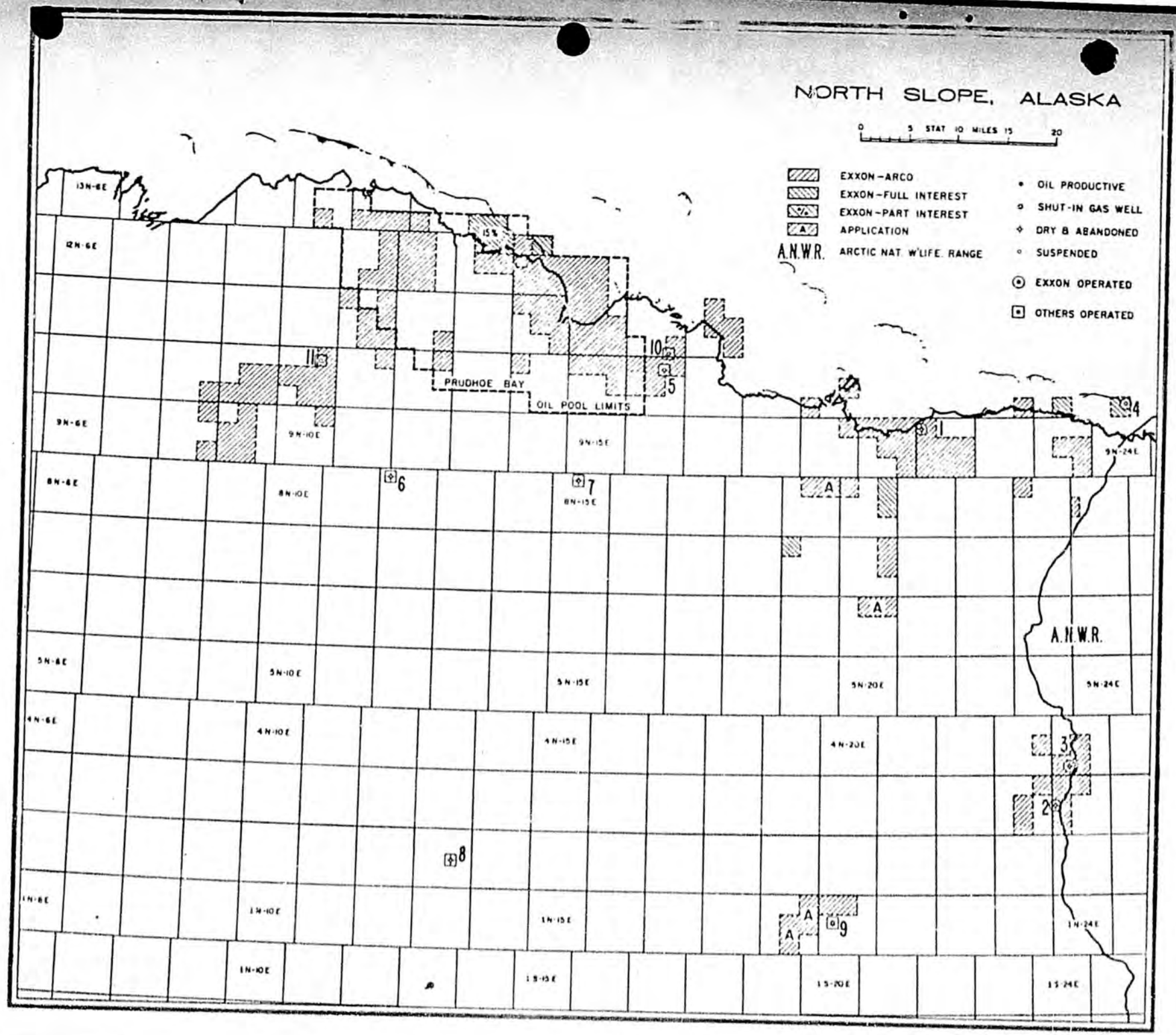
NORTH SLOPE, ALASKA
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AGO 546016

VERIFICATION

W. Ray Booth, being duly sworn, deposes and says that he is Assistant General Manager of the Natural Gas Department of Exxon Company, U.S.A. (a division of Exxon Corporation); that he is authorized to verify and file this document, that he has examined the statements contained in the submittal and that all such statements are true and correct to the best of his knowledge, information and belief.

W. Ray Booth

Subscribed and sworn to before me by the said W. Ray Booth, this 13th day of February, 1976.

Kathryn S. Foulks
Notary Public in and for
Harris County, Texas

KATHRYN S. FOULKS
Notary Public in and for Harris County, Texas
My Commission Expires June 1, 1977

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the restricted service list in these proceedings, in accordance with the Commission's Rules of Practice and Procedure.

Dated at Houston, Texas, this 13th day of February, 1976.

Paul W. Wright

Of counsel for
Exxon Corporation

EXHIBIT "B"

TO

RESPONSE OF EXXON COMPANY, U.S.A.

STATE OF ALASKA

LEGISLATIVE GAS PIPELINE IMPACT COMMITTEE

February 17-18-19, 1976

TO QUESTIONS POSED BY
SENATOR JOHN H. RADER
BY LETTER DATED JANUARY 15, 1976

The letter of Senator Rader contained a list of five questions relating to the potential impact of a recent Prudhoe Bay reservoir performance study conducted by H.K. Van Poollen and Associates, under contract to the State of Alaska. Exxon has received only a brief summary report on the Van Poollen Study. It is understood that a more detailed report will be issued within the next few weeks. The summary report does not provide adequate information to allow Exxon to evaluate the technical methods employed in the study; therefore, the enclosed responses to the Senator's questions are based only on the study results as presented in the summary report and the results of studies that Exxon has conducted.

Q.1. What effect does the recent study, "Predictions of Reservoir Fluid Recovery Sadlerochit Formation Prudhoe Bay Field", have on marketing plans for Prudhoe Bay gas?

A.1. None. The major Prudhoe Bay leaseholders have indicated that it is desirable to commence gas deliveries at a rate of 2 to 2.5 Bcf/D as soon as a gas pipeline can be approved and constructed (estimated to be 3-5 years after the start of oil production). The results presented in the Van Poollen summary report do not conflict with this basic plan.

The Van Poollen study indicates that a reduction in ultimate oil recovery could occur with increasing gas delivery volumes under certain conditions wherein reservoir management plans were not optimized. However, the Van Poollen results demonstrate that there is potential for minimizing, or eliminating completely, such reductions by modifying the reservoir management plan. For example, by modifying certain operating conditions in a 2 Bcf/D gas delivery case (Case 21), Van Poollen was able to eliminate a potential reduction in oil recovery and, in fact, obtain slightly higher oil recovery with gas delivery than in a similar oil rate no gas delivery case (Case 11).

Q.2. How does this study differ from industry and Federal studies?

A.2. The summary report does not provide adequate technical information to permit a detailed comparison of the Van Poollen study technique with other studies. When the results of the Van Poollen study become available and have been analyzed with appropriate consideration given to cost and other relevant factors, we expect that the conclusions will indicate that the optimum producing plan for the field will involve gas deliveries at a rate of at least 2 Bcf/D beginning as soon as a pipeline is available. This finding would be consistent with our studies, other operators' studies, and the Gruy study for the Department of Interior, all of which have concluded that deliveries of 2 to 2.5 Bcf/D are desirable early in the producing life of the field.

Q.3. How accurate can a model be without production history?

A.3. The accuracy of reservoir simulator model studies depends primarily on the validity of the description of reservoir rock and fluid properties, and, to a lesser degree, on the refinement of the modelling program. Based on Exxon's experience and technical judgment, if reservoir properties are accurately described and a technically sound program is utilized, model predictions can be accurate enough without production history to develop reasonable reservoir management plans.

Prior to fieldwide production, reservoir description is based principally on fluid samples, rock samples, production tests, pressure data, and log analysis from wells which have been drilled in the field. Once production commences, it is possible to add information to the reservoir description. It is often the case that development of new fields proceeds such that the reservoir data obtained prior to production is limited. However, at Prudhoe Bay ample reservoir data has been collected and thoroughly analyzed. Consequently, model studies prior to production at Prudhoe Bay are considered to be more accurate than is typical of other new fields where less data are available.

Q.4. Will some production history be necessary before an accurate model is established that will prove feasibility of a gas pipeline for marketing of Sadlerochit gas?

A.3. No. We believe that model predictions prior to production can be reasonably accurate and demonstrate the feasibility of early gas deliveries in the range of 2.0-2.5 Bcf/D. Exxon model studies have shown that reservoir management plans developed prior to production which include early gas deliveries can be modified, if necessary, during the producing life of the field to adapt to variations in actual reservoir performance that may be encountered.

Q.5. How critical are the results of this study in obtaining FPC certification and financing for the gas pipeline projects?

A.5. It is our opinion that the FPC and potential investors as well as interested regulatory bodies, particularly the Alaska Division of Oil and Gas, will consider the results of several studies before making decisions which would affect the gas pipeline project. Studies of Prudhoe Bay reservoir performance have been conducted by the major leaseholders and we expect that these studies will receive due consideration.

As indicated in our response to question 2, we expect the results of the Van Poollen study will be consistent with other studies, which indicate that the optimum producing plan for Prudhoe Bay will involve gas deliveries of at least 2 Bcf/D beginning as soon as a pipeline is available.

VI

CONSULTANTS

AGU 546024

JOINT PUBLIC HEARINGS

of the

ALASKA STATE LEGISLATURE

on

SCR 3, 4, 5 and HCR 11, 12, 13

"THE PROPOSED SALE OF ROYALTY GAS"

January 31, 1977 - February 7, 1977

Juneau, Alaska

VOLUME I

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DR. TUSSING: I just have one comment. In my opinion the report of the administration's Gas Pipeline Task Force is an exceptionally thorough, fair and objective review of the relative merits of the three competing gas transportation systems. In view of the political sensitivity of the issue and the compulsion that agencies generally have to find the most favorable arguments for the policies adopted, I think that this is a really admirable document.

There are only a few points in the report on which I would have a different emphasis and there are a number of assumptions in Dr. Knudson's report that I think were biased in favor of the kind of answer that supported the policy. But I don't think these are crucial to the main conclusions of the Task Force report, and when I start my presentation I'll summarize what I think are the principal conclusions and what the implications of those would be.

SENATOR RADER: Unless the Committee objects, why don't we go ahead and listen to your presentation and then open questions to both of you. Would that be appropriate?

DR. TUSSING: Yes.

SENATOR RADER: Is there any objection to that procedure, Committee? Fine.

DR. TUSSING: Okay. I didn't come with a prepared statement. I have some fragments of things, two of which I would

like to introduce into the record. One is -- let me back up for a moment and identify myself, as you requested. I'm Arlon Tussing. I'm a professor of Economics at the Institute of Social and Economic Research at the University of Alaska. I have been affiliated with the University for twelve years. I have also served as chief economist of the U.S. Senate's National Fuels and Energy Policy Study under Senator Jackson and continue to serve Senator Jackson as an economic advisor on energy and natural resources.

During the last year I have also served as an advisor on oil and gas issues to the State of California, the Provinces of Nova Scotia, Ontario and British Columbia. I have served for a little over a year on the Royalty Oil and Gas Development Advisory Board, during the period of which the initial negotiations were -- took place on these contracts. I have given consideration in a number of forums and for a number of agencies to various aspects of the Alaska gasline question.

There are a great number of issues I would like to comment on, if I have time. I realize your time is limited and I'm going to try to confine myself to some of the high spots and then let you proceed.

SENATOR RADER: You have two documents that you wanted entered as exhibits?

DR. TUSSING: Yes.

SENATOR RADER: Would you identify those for us?

DR. TUSSING: One is an article headed "An Inkling of the Long Journey", published in "Northern Perspectives", which is the newsletter of the Canadian Arctic Resources Committee. This was published only last month but I wrote it in June. So to the extent that there is anything dated in it, you can understand that.

SENATOR RADER: That would be Exhibit No. 11, according to my records. Is that correct, Recorder?

DR. TUSSING: Yes. Oh.

SENATOR RADER: All right.

DR. TUSSING: The second paper is entitled "Natural Gas Supply Outlook for the West" and it is a summary of my comments at a workshop on economic growth in the West in Los Angeles in August.

SENATOR RADER: And that will be Exhibit No. 12.

(Whereupon Exhibits 11 and 12 were duly marked)

DR. TUSSING: The most important conclusions of the State Task Force report are generally consistent with every other important study and with intuitive common sense, and they are the following: Firstly, that El Paso's Trans-Alaska pipeline LNG tanker system would, if it could be approved, financed, and built and operated in the manner proposed by its sponsors, result in the greatest net revenues to the State treasury and the

greatest increase in Alaska gross product, personal income and population. The Alcan systems impact would be second in these respects and Arctic Gas third.

Secondly, with the Arctic Gas system, if it could be approved, financed, built and operated in the manner proposed by its sponsors, would result in the lowest gas transportation costs to the Lower 48. In this respect, the Alcan system seems to be second best and the LNG system worst among the three.

The Task Force report makes one other crucial point but without the emphasis I believe it deserves. In view of the respective routes, design and construction plans, the Alcan system seems to be least vulnerable to cost and schedule overruns, and Arctic Gas the most vulnerable, with El Paso somewhere in between.

Because of the questionable viability and the financing problems of any transportation system for North Slope gas, the prospect of substantial overruns may be the most critical economic issue in choosing among them.

Moving to the contracts for a moment. I intend to get back to the problems of financing. I make no recommendation on whether the Legislature should ratify these contracts. The members should understand, however, that there is no amount of propaganda for lobbying by Alaska or by the three purchasers which will produce a

decision in favor of an LNG system unless Canada makes it clear than an overland pipeline system will not be licensed or that Canada will not be able to come to a decision in the foreseeable future.

I personally expect an unbroken chain of decisions in the United States in favor of Arctic Gas by the FPC staff, Judge Litt, the Federal Power Commission and President Carter, based upon the record in the FPC hearing and the investigations of other federal agencies. I do not mean to imply that Arctic Gas is certain to be approved and to be able to build its system, but if the Arctic Gas momentum is to be broken, it will not be the result of any domestic politicking, but of some objective development. For example, a clear signal of Canadian intentions one way or another. While it is remotely possible that El Paso or Alcan might get an important endorsement somewhere along the line, what is almost inconceivable is that the United States Congress would overturn a presidential determination in favor of a Canadian overland pipeline system to substitute its judgment in favor of an LNG system.

The manifest superiority from a national point of view of the overland pipeline system as available is so overwhelming and the regional interests in the construction of such a system in preference to an LNG system is so

overwhelming that the number of Congressmen, the number of State Utility Commissions and the number of Governors that the purchasers will be able to move on this is only a small time fraction of the existing lead that Arctic Gas has in this matter.

I think that it is instructive that in El Paso's principal market area that there is virtually no support for its project and in fact great skepticism about El Paso's project for a number of reasons, not least that the gas distributors do not want to be exclusively dependent upon El Paso, as they would be, for all the gas entering their market area. And secondly, they don't want the State of California to be exclusively dependent on a single point for the delivery of their gas, a point which could be interrupted by, for example, a fire at Valdez, which would leave them without any gas supply whatever as their existing supplies would have been displaced eastward into markets or, for example, in the Tenneco and Southern systems, for example.

There is simply no possibility, in my judgment, that Congress would endorse an LNG system. Particularly in the face of the cold wave that has now confronted the Midwest and the East and which will have reinforced its determination to get direct delivery of gas, and in view of the developing Westcoast glut of crude oil which is

retrospectively viewed in Congress as the result of the fact that they approved the wrong pipeline in the first place for the oil.

These are circumstances that -- there is nothing which the State of Alaska can do to change. I believe it is clear the United States will favor an overland pipeline through Canada. It also seems likely, that rightly or wrongly, the Federal Power Commission, the Administration, and Congress will accept Arctic Gas argument that an early attachment of the Mackenzie reserves is in the United States' interest and that the Mackenzie route has significant economies of scale compared to the proposed Alcan system. But, the decision will in fact be made in Canada, not in the United States. The United States will accept any overland system that Canada is willing to build in preference to any alternative system.

Canada's orders of preference between the Mackenzie and Alcan routes are not so clear. There are a number of reasons why the Alcan system may make more sense to Canada and with your permission I would like to read a couple paragraphs of my article in "Northern Perspectives" on some of the Canadian reasons for favoring an Alcan system.

"The probable reception of any Alcan proposal by Canadian authorities has been a most difficult issue to

forecast. A major appeal of the Arctic Gas project is purportedly its early (if not necessarily more economical) attachment to the Mackenzie reserves. Without this feature, it may be asked, what is the advantage to Canada of accommodating the United States in moving Alaska gas?"

"The attachment of the Mackenzie reserves may, on the other hand, be seen as a major disadvantage of the Arctic Gas system, from at least one Canadian standpoint. There is no particular reason why Canada should not accommodate the United States with a transit line across Canadian territory; after all, a substantial portion of Canada's oil and gas supplies transits the United States. There would seem to be little objection in Canada on nationalistic grounds to American gas moving in either an American or a Canadian-owned pipeline across Canada. The Mackenzie project, in contrast, raises the issue of an American-dominated consortium developing an important frontier area of Canada. The fact that an early MacKenzie connection is being justified in the United States by the (doubtful) proposition that it would lead to greater Canadian exports to the United States aggravates its potential difficulties in Canada. Both its timetable and logistics would be dictated by the convenience of the American interests. The native claims and environmental complications of this route are well known."

And incidentally, I expect that Justice Berger, who is the commissioner for the Canadian government in examining native claims and environmental implications of the Mackenzie pipeline, will come out strongly against the Arctic Gas proposal and against any major pipeline development in the Arctic pending the settlement of the native claims and the resolution of some presently unresolvable environmental issues. He will point out, I believe, that neither of these objections is nearly so strong with respect to a pipeline through the Yukon Territory along the Alcan route.

"The 60 trillion cubic feet of proved reserves in the western provinces", I think it's now about 62 trillion cubic feet in Alberta,"are enough to sustain the expected growth of Canadian demand plus present export" commitments "for about ten years. This would be the case even if there were no further discoveries" in Canada, "but recent exploratory results in Alberta have been rather encouraging, more so in fact than in the delta area. For this reason a decision on an Arctic pipeline carries much less urgency for Canada than it does for the United States."

In other words, Canada does not need a pipeline connection to its frontier areas for ten or eleven years even if there were no further -- to be no further discoveries in Alberta or British Columbia.

"More importantly, however, a decision today in favour of immediate development of the Mackenzie Delta-Beaufort Sea region can be seen to prejudice whether that region or the Arctic Islands (where recent exploration seems to have been more successful) shall be developed first. Either project could strain the capacity of domestic capital markets so that simultaneous construction of the two major pipeline systems under Canadian majority ownership is almost out of the question."

And I go on to say that it is not obvious which of these considerations will finally come to play, but "A decision in favour of Arctic Gas would" "be a reluctant one". It would have to be in the face of a firm decision by Justice Berger who in a sense occupies a similar position as Judge Litt in the procedures in the United States, and it "would be opposed by many quarters within the Canadian federal government, by several provinces and by a large body of Canadian opinion."

As you probably know, the Trudeau government faces an election no later than the fall of 1978. The liberal party is in great trouble, Trudeau is very unpopular at the present time and to run over the Natives and the environmentalists at this time in favor of an Arctic Gas pipeline is probably unlikely, it would be a very impolitic. So there is on the other hand and I have absolute

confidence in this, there is a determination at the highest levels of the Canadian government to work out some joint accommodation with the United States for transportation of oil and gas and through exchanges of oil and gas. And I believe that the Alcan proposal offers a very important way out for the Canadian government of its way out of its dilemma.

Turning back to our contracts and the prospects of the Trans-Alaska Pipeline, the only serious substantive argument for the El Paso system from a national standpoint, the only one that has any credibility is that Canada will not license an overland pipeline under terms acceptable to the United States. Only Canada can prove or disprove the truth of this proposition and the Administration and Congress are going to wait for this.

Now the -- I do not want to say that there is no chance for a Trans-Alaska pipeline. There is no chance for a Trans-Alaska pipeline so long as there is a chance of a Trans-Canada pipeline and there is nothing that Alaska or El Paso or any of the purchasers can do to influence the decision from the United States in that respect.

The corollary proposition advanced by El Paso that the Canadian government is incapable of granting acceptable terms for an international pipeline because

its treaties don't bind the provinces is without merit and can be easily dismissed. The premieres of both British Columbia and Alberta have expressed their intention to lay this question to rest to the extent that the Canadian federal government cannot bind the provinces. The provinces have independent authority to make treaties and those of you who are familiar with the Columbia River treaty will recall that it is a treaty between -- or among the United States, Canada and the province of British Columbia. Both Premier Lougheed of Alberta and Premier Bennett of British Columbia have made it absolutely clear that they have no objection to joining in any protocol providing for nondiscriminatory treatment, taxation, regulation, and for that matter a complete quitclaim of regulatory jurisdiction over a transit pipeline that carries United States gas. So I think that that issue is totally a red herring.

The scenario I see developing on the approval of the pipeline -- or on the determination of a pipeline route is that the Federal Power Commission will find in favor of Arctic Gas, along the same lines as Judge Litt's finding, on the basis that it is environmentally superior on the basis that results in lower cost to consumers, the basis it can be built faster, that it is more easily expansible, and the whole range that the Federal Power

Commission will find it superior in every respect.

At about the same time the Berger Commission findings in effect vetoing Arctic Gas will come out in Canada. Now if you'll recall the language of the Alaska Natural Gas Transportation Act, it says the presidential determination -- the FPC recommendation, the presidential determination shall be made without respect to whether Canada has reached a decision on this.

What the FPC decision for Arctic Gas and the Berger decision against Arctic Gas will trigger is negotiations between the United States and Canadian government and among the various proponents of gas pipeline systems to see what kind of system can -- is agreeable to all the parties. And it seems to me that the system that is going to be most acceptable to all the parties is a system along the Alcan Highway but departing in some degree from Northwest's and West Coast's strategy for that. In other words it would be a higher capacity pipeline than envisioned by the sponsors. As -- one combination would be to use El Paso's engineering and pipeline design for the northern part of the route. El Paso believes that with high pressure, with 1670 psi they can move up to 3 1/2 bcf a day through a 42 inch pipe. I think that a 42 inch pipe is one of the strongest elements in the Alcan design because that is

the kind of pipe that can be rerolled in existing North American facilities.

A disadvantage of the Arctic 48 inch scheme is that it requires the building of a new plant by Stelco for the production of that pipe and it introduces another -- just another of a whole series of uncertainties into what I believe is an oversized -- already an oversized project.

So returning again to the contracts, I do not see what the State accomplishes in terms of the advancing of its goal by selling the gas now. I will -- in response to questions I'd be willing to elaborate on what I think the significance of these contracts are, but I would like to go ahead and spend a couple minutes on what I think some of the problems of building and financing an Arctic Gas pipeline are, regardless of who built it.

There -- these projects are enormously risky no matter what the sponsors and their financial advisors say. Their ability to be financed in conventional -- by conventional private means is extremely suspect. And that -- I'm sure that Whitewell's representation to El Paso and the financial advisor's representations to Arctic Gas and to Northwest are qualified in the same way. That is, if you get as much gas as you say you are going to move through this system and if your costs are the

costs that your engineers say you will have and your schedule is what your engineers say you can accomplish and if you do get all the necessary approvals, then the financial -- and you do get the all events full cost of service tariff from the Federal Power Commission and the state utilities that govern the distributors -- or the customers of the system, then you can finance this through conventional project financing.

What I would question is whether all those -- whether all of those conditions are certain enough that the insurance company's pension funds and the other institutional investors that have to buy this pipeline would be willing to risk what may be Ten to Twenty Billion Dollars in financing.

In the first place, there is uncertainty about the gas supply. Now the -- I believe the State's reservior engineers project a probable production, permissible production, or optimum production of about 2 bcf a day. Now that is about or perhaps below the minimum threshold of Arctic and El Paso. That is about the design threshold for Alcan.

Now it is conceivable that after two or three years experience in oil production the Alaska conservation authorities may conclude that that rate of production is not in the State's interest, that the loss of oil -- the

value of the oil foregone by that production is greater than the value of the gas produced. Nobody knows what this is going to be. The fact that all the producers and the State of Alaska and the gas purchasers all believe that they can produce say two bcf a day safely isn't good enough for the lenders. They have to have some notion of what the likelihood -- the downside likelihood is. And the downside likelihood -- if there is only a ten percent chance that production will be 1.6 bcf per day and 1.6 bcf per day is not enough to guarantee the payment of the debt on this pipeline, then you just won't be able to go into the capital market. We have the problem of delays in capital cost overruns. Actual construction costs may exceed estimated costs by substantially more than they affect general inflation.

Two years ago, with the help of the Library of Congress, I did some research on this and was unable to come up with a single large custom engineered construction project in the United States over the last ten years which had not exceeded its initial engineering cost estimates by a factor of less than two. And the experience in North America with big custom-engineered construction projects has been that they typically cost two or three times their original projections, even including an allowance for inflation. The cost estimators are like

accountants and they prefer a solid, empirically based figure. That is, so many cubic yards of cement at so many dollars a cubic yard to a realistic figure. "They do attempt to project the increase in anticipated labour rates and in the prices of specific materials", and the inflation rates for those specific materials, "but they don't take into account the fact that huge projects, particularly if they involve new technology", as both systems do, both Arctic and El Paso does, "or a remote construction site," and this would apply more to Arctic, "usually don't work the first time around, nor that both the purchaser and the licensing authorities change their minds several times in the course of construction. The cost engineers don't appreciate that such projects are usually clumsily managed and are subject to a number of re-organizations during their design and construction. They don't allow for the fact that materials and equipment are always late and often mis-specified or defective," and that such "enterprises" "suffer not normal, but abnormal labour cost increases. Because of their size and urgency, they are especially vulnerable to wage pressure," and "to featherbedding, and" also "to racketeering."

And I needn't go into great lengths on the problems of the Trans-Alaska Oil pipeline, which will --

whose costs will exceed by ten times the initial estimates by the sponsoring companies. I do not project a ten time overrun for Arctic Gas but I think that a doubling of their present projections would not be an unreasonable anticipation in view of the history of large projects in North America. Let's assume that Arctic Gas or that El Paso's project would cost Twenty Billion Dollars and that it would have to be paid for in twenty years and "assume that the investors should receive a 15 percent pre-tax rate of return on total" investments. "Under a conventional utility accounting scheme, the project would need a first year cash flow of four billion dollars just to cover its fixed costs. On a discounted cash flow basis" which is a more rational financial way of looking at it but is not customary in utility accounting, "the annual fixed charge would be about $3.2 billion."

But "with a throughput" of about "a trillion cubic feet" a year, that is about three bcf, "we are talking" about "$3.20 to $4.00 per thousand cubic feet" for transportation costs alone. If less gas can be delivered, if we are talking about two bcf a day, we are talking about Five to Seven Dollars a thousand cubic feet. Now "this charge doesn't include the cost of developing the gas fields, any return to the producers," to the royalty owners, any "operating costs or" any "costs of distribution."

Now both El Paso and Arctic insist that the consumers will accept any price because of the rolled in feature. Now not everybody agrees with this and in fact none of the government sponsored studies -- the Aerospace -- FEA study estimated that "no market for Prudhoe Bay gas would exist in 1985 at a 'city gate' price exceeding $2.40 per million BTU (in 1975 dollars). The Interior Department's study reaches a similar conclusion." Now this price you are almost certain to get, "even without implausibly large cost overruns or shortfalls" in the gas distribution system.

Now, "one assumption of" these "studies mentioned" "is that natural gas" prices have been decontrolled, "and that the Alaska gas is" therefore "priced incrementally."

Incidentally, the -- I don't want to spend a lot of time on it but it is not clear whether deregulation would increase or reduce the price of Alaska gas. I think there is a very strong case for expecting that it would make Alaska gas less valuable for a number of reasons. Deregulation would increase the price of gas in the Lower 48 and therefore reduce consumption in the Lower 48, increase production from the Lower 48 and reduce the gap -- the shortage.

It would also reduce the amount of low priced gas that the pipelines and distributors get which they can

roll together with expensive gas to come out with a price that satisfies their consumers. Now I don't want to predict absolutely that deregulation would make Alaska gas less valuable, but I think that that's the probable effect, that by easing the gas shortage in the Lower 48, they make it less willing for gas distributors to pay more for that gas than it is worth at the burner tip.

What it is worth at the burner tip to the average consumer is roughly the price of fuel oil. Now there is some consumers that will pay substantially more and some who will pay only the price of coal or residual oil and so on. But the average consumer is competing with fuel oil. In a deregulated market, after a few years, you'll find that gas distributors will not pay more than that for gas because they don't have any cheap gas to average it with.

So, anyway there are market risks -- there are gas supply risks, market risks, cost overrun risks, and of course you know about the political regulatory and other institutional issues, things like native claims in Canada, the fact that virtually nobody seems able to get any sort of terminal in California. I have looked at this problem again for several different agencies and I wouldn't count on any proposal which requires a major terminal in California at this time until there is a

substantial change in the internal institutions of that state or a substantial change in federal-state relationships.

It may be that there is just no way to put a major terminal in California. Anyway you have these problems, so you have the -- so these risks generate the financing problems.

"The financial consequences of the risks I have listed are magnified by the fact that neither" El Paso nor Arctic "can be built in smaller self-sustaining stages." Each is a total "integrated system which" will not flow any gas or flow any cash until the whole thing is completed. "Most of the capital invested", that is Ten to Twenty Billion Dollars or more, will be exposed to all the risk factors for the entire planning and construction period.

Now private lenders "simply will not accept the risks of this sort, and neither project's sponsors are financially large enough to carry them, even if they were willing to do so", and they are not willing to do so. All of the projects propose an "all events" tariff in which the sponsors would be guaranteed a return on equity, as well as a return to debt service, whether or not any gas is ever carried by their project.

El Paso proposes to use federal loan guarantees

and Arctic has talked about federal indemnification for overruns. But, neither the "full cost of service all-events tariffs" nor government guarantees are presently in the works and none of these projects can be financed without some sort of government backup. And this is something that I think is independent of the numbers you come out with on any particular thing.

The financing schemes are very conditional and I think that all the sponsors are -- expect they will ultimately have to go to the federal trough either for a subsidy or a loan guarantee, which is the same thing as a subsidy, because they will not be able to produce the cash flow that they project and they will have overruns.

The President, when he makes his recommendations, or the President in his negotiations with Canada, are going to have to come up with something that can be financed.

Now, turning to Judge Litt's conclusions on this, Judge Litt is in effect asking somebody to build an over-sized pipeline on speculation. He is saying that in view of the vast amount -- the vast potential of the North Slope, all the way from Pet Four through the State leases, through the wildlife range, through the Beaufort Sea and the Mackenzie Delta, there may be a vast amount of gas and it is wasteful to build a minimum scale system as Alcan

proposes, simply to handle most economically the gas that we know for certain can be produced. But, he is asking somebody to take the risk and the somebody is basically the investment community that is not going to take the risk, even if the probability that the throughputs necessary for Arctic Gas are -- say even if it is a ninety percent probability that Arctic Gas is viable.

Then he turns around and says, "well, the oil companies ought to take this risk." Well, the oil companies are not in this business. The oil -- he is asking the oil companies to put Three, Four, Five Billion Dollars on top of the Four to Seven Billion Dollars it is going to take to develop the field to produce the gas. He is asking them to put it -- to take money that they could use in high return risky ventures and put it into an operation that is going to have a public utility rate of return, where their going to be constrained to make nine percent or something like that. And it just isn't going to happen. It is an appeal to patriotism or altruism or something like that that is completely unrealistic.

If Judge Litt and the Federal Power Commission and the President want a big diameter, high pressure pipeline from the North Slope, they are going to have to get the American people to pay for it and to accept

the risks through the political system and there is nothing wrong, say with the principal of an all events tariff as long as the probabilities are good, as long as consumers have a substantial chance of benefiting, why shouldn't the consumers take part of the risk? It is not going to happen that way. The Public Utility Commissions don't think the risks justify it, they don't like the idea of socializing private risk in a situation where the investors are guaranteed their return while the consumers and the public take -- have the downside risks. So, when the President of the United States and the Premier of Canada get together to figure out what the system is going to be, they are going to have to look hard at the financing and the other system.

Now, looking at the faults of the Alcan system, there is something from the point of view of the Federal Power Commission. It seems to me that this principal fault can easily be resolved. It is desirable to have a forty-two inch pipe because that pipe can be built and can be rolled in present mills and its -- the technology is a lot more practicable.

El Paso believes that it can run a lot of gas through -- a lot more gas at a higher pressure through the pipe. If the Alcan people were granted a certificate on the condition they would put in a heavy guage pipe.

which could operate with sixteen hundred seventy psi, if the gas were available, by adding more power the incremental costs would be relatively small.

I think these things can be settled but they probably have to be settled in negotiations. It seems to me in conclusion that none of the systems as presently proposed and none of the financing arrangements are presently viable, and that we have yet to see the last of the combinations and permutations. I would say, however, that there is nothing the State of Alaska can do to advance a Trans-Alaska Pipeline LNG system within the U.S. political system. If there is going to be such a system, it will be selected by the Canadians because of their inability or unwillingness to authorize the prompt construction of an overland pipeline by one route or another.

SENATOR RADER: Representative Meekins?

REP. MEEKINS: I don't know exactly where to begin.

SENATOR RADER: Maybe a motion to adjourn. As a matter of fact we should have a recess motion. Let's take a recess here for ten minutes.

(Whereupon the hearing was recessed at 4:00 p.m. and reconvened at 4:15 p.m.)

SENATOR RADER: The Committee will come back to order. During the recess we had several conferences and we

decided that no matter what we did, we would have lots of authority for doing it. So, and that includes nothing, I guess. As I recall, Representative Meekins, you had the floor when we recessed.

REP. MEEKINS: Thank you, Mr. Chairman. I hate to try to characterize what you said, but as I understand it, you say that while it is clear that the El Paso line provides great benefits to the State, that in your view it seems very clear that the contracts that were -- that are the subject of this -- of these committees are irrelevant to the decision upon which -- about which gasline will win final approval and that the actual decision will be made in Canada. If that is the case and if it is as clear to you as it seemed in your presentation, how do you explain the fact that administration experts say the opposite?

DR. TUSSING: Well, I think that may be more your speciality than mine. The purpose of these contracts is essentially an internal Alaska political purpose. Suppose you were the Governor and you had become -- and you were under assault from OMAR and the Anchorage Times and from the Anchorage business community for not having given one hundred percent support to everything that the El Paso enthusiasts wanted. And suppose as Governor you were also convinced by your own investigations that El Paso

had very little chance and you're -- you would probably be concerned that when Arctic Gas got the final nod that these people would point the finger at you and say that it is only because you didn't sell the royalty gas, or its only because you made these noises about Alcan being an acceptable second choice and that you didn't dump all over the Canadians like we wanted to.

Well, it would seem that it would be an astute political move to go ahead and call everybody's bluff. You will recall that the Legislature almost unanimously, under the leadership of Senator Rader, urged the -- in fact, demanded that the administration go ahead and do this. So, the Governor now can come back to the Legislature with what I think is really a contract that doesn't mean anything for the --

REP. MEEKINS: Is this the hypothetical Governor?

DR. TUSSING: Yes, this is the hypothetical Governor. He now comes back to the Legislature with this can of worms.

SENATOR RADER: A realistic can of worms, huh?

REP. MEEKINS: And a real Legislature.

DR. TUSSING: And you look at it and you decide there is some problems with it, that the State may give up too much in it and I think that Mr. Moody and Dr. Swanson have some valid criticisms -- technical criticisms of the contract or that maybe you shouldn't have sold all the gas, or a

whole series of reasons. Or, you may not be convinced that you are buying any political influence. But, what happens if you vote it down? And say -- where is the finger going to point when Arctic Gas gets approved? El Paso can say -- pick up its marbles and go home or something like that. It becomes a real psychological blow, at least within Alaska, to the El Paso effort. And, you guys, by voting this thing down bear the onus. You're the ones who defeated the Trans-Alaska Gas Pipeline.

If you pass it, this hypothetical Governor has exercised his leadership over this hypothetical fractious and undisciplined Democratic Legislature and carried the ball for Alaska. And, when and if Arctic gets the approval, he can show that he has done everything he could, and, in fact more than anybody reasonably expected him to do. He has done just what the enthusiasts for El Paso -- what OMAR has been saying he should do all along. They can't fault him on that. He has managed to carry along these legislators who were riding off in every direction. So, that -- that is what I think the fundamental significance of these contracts are and that is why I say I am not sitting in your seat, so I won't -- and I'm probably not the kind of person who could ever get into one of your seats. And so I won't advise you -- I won't advise you of what you are doing.

SENATOR RADER: Representative Meekins still has the floor.

REP. MEEKINS: Mr. Chairman, I just want to thank you for pointing that out. I never would have thought of it. I would also like you to direct him to be more forthright.

SENATOR RADER: Quit beating around the bush, now. Senator Colletta?

SENATOR COLLETTA: Yes. Dr. Tussing, you know that opened an area that, since you are venturing opinions, it seems to me out of the presentation on the political activities rather than the economic ones that affect the line. You missed the first day but the entire congressional delegation, without regard to party, also say that on the national level they want unanimity of support for this line. Now, am I, you know -- should I believe from a conclusion of your answer to the last question, that all of us are playing a game and isn't the parallel to this line identical to the oil line that came to Alaska on a one vote measure?

You know, I can't help but infer, at least in my own mind, from what you are saying is that regardless of what we do or the congressional delegation does, not only Alaskans, that this decision will be made by two beings and they don't need us, we're playing the game and I would suggest that is wrong. I take offense to it, because in the oil line there were those people who felt

very strongly that possibly a route other than through Alaska was beneficial and stood up and took the flak. And I would suggest that in this body right here there are those who still have not concluded that maybe the all Alaskan route is the way to go.

I really take great offense that you are lumping us into playing a show, and that isn't true.

DR. TUSSING: Well, let me deal with the first question -- or the second question, and that is the parallel with the Alaska oil pipeline. I don't see a significant parallel. In that case there was only one proposition before the Congress. There were no responsible corporate sponscrs for a Trans-Canada pipeline. There was the unanimous support, the State of Alaska, the oil companies and the administration behind that proposal. Yet the opposition to it managed to mobilize something like forty-two votes for a Canadian alternative which didn't exist.

Now, we have an entirely different situation. The momentum and the weight of the responsible corporate sponsorship, the weight of the agency endorsements within the federal government are all with the Trans-Canada system. The momentum is there. When the Trans-Alaska Pipeline bill was before the Congress in 1973 it was right at the height of the Arab embargo and it was the

only thing there that Congress could possibly ratify. And, it -- there is some question of whether it would have gone through without all that -- without all those preconditions. Now the momentum, the establishment, the route to be azoic -- and it's got a far higher -- it starts with a far higher proportion of support, despite the fact that it has got responsible corporate opposition and it has got the State of Alaska and a number of other entities opposed to it. It starts -- Arctic starts stronger in Congress than the Trans-Alaska Pipeline -- oil pipeline ever got in Congress. So, that I don't think it is parallel.

Now, going to the question of the delegation. I hate to -- I'm a little diffident about beating my own drum, but on major national, political questions concerning Alaska, the biggest ones, our delegation, whoever they have been, with perhaps one exception, and our administrations, whoever they have been, have been one hundred percent wrong on these issues and I think that I have got a little better record on that.

Going back, for example, to the question of whether the Secretary of the Interior could or would lift the land freeze and be able to authorize the pipeline without the settlement of Alaska native claims, or to a more fundamental issue, whether there was any legal

merit or political horsepower nationally behind the native claims. That were -- with the exception of the second in which Senator Gravel, when he did come in in 1970, was an advocate of the native claims, our delegation and our State administration dismissed the possibility that this could hold up the pipeline and I was practically stoned out of Anchorage in 1969 when I told the Chamber of Commerce that there couldn't be an oil pipeline for maybe seven years and going through the things that had to be done. Well, this was against the unanimous consensus of our administration and our delegation.

Come again to about 1972, when the question of the destination of the oil and the West Coast supply/demand balance, you had unanimous profession by the industry, by the federal administration, by the State administration and by our delegation that demand on the West Coast would exceed production, combined California and Alaska production, and that the question of exports to Japan was not a real question because there would never be a surplus of oil on the West Coast. And, again, I think that I was probably alone in the State in maintaining that this would be a problem.

Our delegation and most Alaska public officials suffer a disease which is endemic to isolated colonial areas and that is, that it is very easy to believe ones

own propaganda, to have wishful thinking. Now, I can't believe that our delegation really believes that there is a substantial chance that they could get a majority political vote for the Trans-Alaska pipeline.

I do know that it would hurt them very badly politically in Alaska to come in and do the same kind of thing I do, that is, deliver the bad news. Again, I have very little chance of replacing Senator Stevens or Senator Gravel because I do tell the voters and the politicians the bad news rather than the good news. And so, I can't go into their heads and say why is it that they give unanimous support. I just ask you, what would be the political -- what are the political risks to them of saying there is nothing you can do to advance the Trans-Alaska pipeline, better forget it, buddy. You know what would happen to them, regardless of whether that is their best judgment. There is no political to them at all in saying, "Go, man, go. Let's do everything we can for El Paso." So, I don't know what -- you know, I don't know what is in their heads but I don't think that you can really weigh their statements as an accurate objective judgment of what is going to happen in the United States Congress.

SENATOR RADER: Any further questions?

REP. CHATTERTON: Yes.

SENATOR RADER: Mr. Chatterton?

REP. CHATTERTON: Thank you, Mr. Chairman. Dr. Tussing, I am told that there was a recent poll conducted by the Rowan group of public opinion and the findings of that indicated in the order of eighty to eighty five percent of the citizens of Alaska favored an all-Alaska gas line. Are you suggesting in the comments you just made that we who represent those people should subvert their opinions?

DR. TUSSING: Not at all. I'm saying that you -- you as members of the Legislature have to make this judgment for yourself on the basis of the way you judge public opinion and the way you judge whats right and wrong. That is not for me to say. I said I will not recommend the vote one way or another on this.

SENATOR RADER: Representative Gruening?

REP. GRUENING: Well, this may be a clarification of Representative Chatterton's question, but, is public opinion subverted whether we reject or approve these contracts? As I understand it, the question before us is approving these contracts and not necessarily the support or non-support of the El Paso line. In your testimony the two are not necessarily, in terms of actual effect, are not synonymous.

DR. TUSSING: Is that a question?

REP. GRUENING: Yes.

DR. TUSSING: I don't -- I agree with you that the -- that it is possible to be in favor of the Trans-Alaska pipeline and to be against this contract, or say to conclude that this contract doesn't affect the outcome.

SENATOR RADER: Representative Miles was seeking the floor.

REP. MILES: Dr. Tussing, you indicated that there was no support for the El Paso project in its market area, I believe. Am I correct there?

DR. TUSSING: No. I said there is no substantial support in California. I was talking of California's principal market area.

REP. MILES: Just California only?

DR. TUSSING: Yes.

REP. MILES: I see. Well, this is a major market area, I understand.

DR. TUSSING: Yes, California is El Paso's biggest market area.

REP. MILES: Why -- getting off of politics and onto economics for awhile, why would El Paso spend so much money in developing a project if there is no support there? Am I missing something? I obviously am.

DR. TUSSING: Well, again you are asking me to speculate about peoples motives and I can just try to put myself in their place. El Paso, in the first place, wants to

assure its customers that it is doing everything it can to obtain gas and a major campaign to build a pipeline system -- a transportation system from Alaska into their market area is such a gesture and it may earn them some Brownie points even if they -- you know, even if they aren't successful. That is one consideration. Now, El Paso is also getting very heavily involved in LNG technology all over the world and wants opportunities to develop and expand this technology.

Now, whether or not how great a probability of success they have, or they believe they have, I don't know. I think it's probably a good gamble for El Paso to stay in the race in the expect -- on the possibility that Canadians might not come through. That then El Paso is posed with an alternative system.

I would not say surely that the El Paso system will be approved even if the Canadians can't get their act together or if they turn down Arctic and Alcan, but at least El Paso is certainly number one -- number one in the line with this and they would -- if they successfully complete it -- financed it and completed it and operated it, they would add more cash flow to the corporate treasury.

Now, why do they want the gas? Why do they want the royalty gas, because they are in the gas business.

They want gas to flow through their system. They would want the gas to flow through their system regardless of what system were chosen. I'm sure that once -- that if a system other than El Paso was approved, El Paso will be back here at the state trying to buy the royalty gas and will be back trying to buy gas from the producers.

I don't think there is any mystery of what their general motivation to the enterprise is and for risking money for the enterprise. It is a perfectly legitimate kind of corporate venture.

SENATOR RADER: Representative Swanson and then Senator Huber

REP. SWANSON: Yes, I just -- I'll turn the clock back just a couple of minutes and something has disturbed me through all of these hearings, that we are here talking about a gas contract and using data that is two years old. Now I'm one of the people who endorsed a all-Alaska route two -- going on three years ago and we are still using that support in the propaganda used today. We have not passed a resolution since we came to this Legislature endorsing --

SENATOR RADER: Representative, do you have a question of the witness?

REP. SWANSON: Yes. Well, I kind of resented what was said here awhile ago and I feel a little bit like that I have the right at this table or any other table to state

that I don't think that the --

SENATOR RADER: If you feel you have been attacked, you have a right of personal privilege but the purpose of this hearing is to make answer -- ask questions of these witnesses now.

REP. SWANSON: All right.

SENATOR RADER: If you wish to why proceed.

REP. SWANSON: I feel like you do, John. I would like to ask you, in your remarks concerning the support of the El Paso route, do you take of what has happened today or two years ago?

DR. TUSSING: I'm not sure what you are referring to.

REP. SWANSON: Well, in your -- in your statements of the Legislature totally supporting the El Paso route.

DR. TUSSING: Oh, the last session of the Legislature adopted a resolution urging the administration to make a gas sale to El Paso and to other supporters in the Trans-Alaska route.

As far as I know, you are perfectly correct, this Legislature has not adopted any resolution to that effect.

REP. SWANSON: Thank you. Thank you, Mr. Chairman.

SENATOR RADER: Senator Huber?

SENATOR HUBER: Thank you, Mr. Chairman. Mr. Tussing, the Four Dollar price that you mentioned on gas, is it correct

to assume that was an mcf and that it would compare to Twenty Four Dollar a barrel oil price or Sixty-five to Seventy-five Dollar a ton coal price with eight or nine thousand BTU's assumed?

DR. TUSSING: Well, those -- those are the equivalent prices. I don't want to be pressed to give a specific price because one of my points is that nobody knows what the price is going to be. It is very likely to be much higher than the sponsors of any of these projects are telling us, but whether the overruns are going to be five percent or five hundred percent, we can only speculate and so --

SENATOR HUBER: Would you care to expound on the saleability of Four Dollar gas compared to Twenty-four Dollar oil, at this time?

DR. TUSSING: Thats -- it's a complicated question. The value -- as I said before, the value of gas to the average homeowner or commercial user is roughly the value of fuel oil plus the -- say, some amortization of his cost of conversion if he has to convert from oil to gas, and so, so at the burner tip, gas is on the average worth maybe Two Dollars and Twenty-five, Two Dollars and Fifty Cents a million BTU today.

Now, if we expect the OPEC oil price to go up roughly with inflation, maybe six percent a year

and so on. We can expect that average value of gas to go up. Now, the gas distributors gather together gas from various sources at various prices and they sell it at an average price. The gas distributors and the pipelines are also required by their franchises or by their licenses to provide this service -- to provide gas to all comers at a cost of service price. And so, if they have a shortage, if their demand is greater than their supply, they're often -- they will be willing to pay more than the gas is actually worth at the burner tip to acquire it and put it in their system.

Otherwise, they have consumers in which they have legal -- to whom they have a legal obligation to serve, who go short. So that for small amounts of gas, at the seasonal peak, or when there is some sort of emergency, the gas distributors may be willing to pay Ten Dollars, may be willing to pay the equivalent of One Hundred Dollar a barrel oil to avoid turning off the valve to their consumers. So -- but you can't take Ten Dollars a thousand cubic feet as the value because you have got to look at the whole cycle. Now, if the gas coming out of the pipeline costs the distributors Six Dollars a million cubic feet and he has got to -- or a thousand cubic feet and he has got to sell it at an average price of say Two Fifty, that means he has got to get a hell of

a lot for it in the peak season. He may have to get Ten Dollars for it at the peak season and then he has got surplus gas, he's paying for the gas that comes through that pipeline in midsummer even though his regular residential customers don't need it. And, in that case, he has got to sell it in competition with coal for a dollar or residual fuel oil for Two Dollars.

So, it's not -- there is no single market value price and to know how much, say six hundred fifty bcf of gas or say one hundred million cubic feet of gas per day is worth to a gas distributor in Chicago or Los Angeles depends upon how short they are, how much they have already cut off their low priority customers, what their other alternative gas supplies are. Do they have a lot of flowing -- of gas flowing under old regulated contracts where they are paying Thirty Cents or Fifty Cents and to be used to subsidize the purchase of expensive gas. You have to look at all of these things and then each distributor figures out what the gas is worth to it and what the cheapest alternative is. If it goes to -- say it goes to Four or Five Dollars, they will look at making synthetic methane from oil which is very expensive for base load supply. It is more than the average consumer will pay but if they are trying to -- if they are just trying to fill a gap, it is a lot less risky to build a

propane air plant or a plant to make methane out of naphtha for Four Dollars an mcf than it is to commit yourself to twenty years of take or pay year in and year out Four Dollar gas from Alaska. So, Four Dollars is cheaper from an SNG -- from an oil SNG plant than it is from a gas pipeline and I just can't give you the answer and say at what point, at what price Alaska gas prices itself out of the market.

The Interior Department's -- the FEA study that says Two Forty -- Two Forty, that's too low in view of their opportunity to roll it in. The El Paso's assertion that the distributors will accept the price no matter how much it costs is pure crazy. There is just no substance for that, there is a limit and I can't tell you -- probably Dr. Swanson's firm has done work in this as to what the long term limit to the city gate price is, but I can't tell you. It is somewhere between Two Forty and infinity. And I don't think its -- I really don't think it's much more than Four or Five Dollars.

DR. SCOTT: Somewhat short. This way from infinity.

SENATOR RADER: Senator Huber?

SENATOR HUBER: Mr. Chairman, the other question I have, I have trouble in phrasing it and I have noticed that you have returned to being a bit on the tough side and I don't think you will give me the latitude that you gave Senator

Colletta, so I'll let it go.

SENATOR RADER: Well, now that we have established that I'm an unfair chairman, are there anymore questions? Mr. Carpenter.

REP. CARPENTER: I'm going to make an extension of Senator Colletta's question. Dr. Tussing, you said that you angered the Chambers of Commerce by saying there was going to be a hiatus in construction of a Trans-Alaska oil pipeline due to land claims and so forth?

DR. TUSSING: Yes.

REP. CARPENTER: Well, refreshing your memory a little bit, you actually angered them because you said there was no political chance of a Trans-Alaska oil pipeline, there was going to be a Trans-Canadian oil pipeline and that is what got everybody on you.

DR. TUSSING: I never said that. Never, never, ever.

REP. CARPENTER: Our memories differ.

SENATOR RADER: Are there any other -- I'd like to ask everybody to keep themselves on the subject of inquiry here. There is opportunity -- there will be opportunity for each of us to express ourselves at a later time as to whether Dr. Tussing's remark characterized a hypothetical or a real governor or legislature or a congressman. We needn't confront him with that today. Our purpose here today is to take his testimony on the subject before us and I

would like to limit the questions to that if we might. Senator Croft?

SENATOR CROFT: Could I interrupt your remarks and ask a question? I am curious what you think the prospects are that any pipeline, Arctic, El Paso, Alcan, or another one if it is proposed, will actually begin construction sometime in 1978. Judge Litt talks about a dollar well-head value being about the upper limit and all of the projections are that these -- each of these projects will have a higher amount than that. You have talked about all events tariffs and types of public financing that haven't even been considered yet. What do you think the prospects are? You have indicated Arctic is likely to be approved, do you think that means that they can actually begin the construction on the time schedule they are talking about?

DR. TUSSING: I don't -- I'm very skeptical as to whether Arctic can be built. I think it can be approved, that's the -- I think it can be approved in the United States and all other things being equal, it will be approved in the United States. It will get the endorsement of the FPC. But, shortly after the FPC decision we'll get the Berger decision, the National Energy Board in Canada will be second phase hearings next month. The NEB -- I don't know what the NEB will do, it will probably hand the hot

potato to the cabinet -- to the Canadian cabinet. But, once the FPC makes its decision and once Berger in effect makes a contradictory decision, what is on the agenda is for negotiations between the United States and Canada as to what can be worked out. And the final decision depends first on those negotiations and second on resolving a lot of questions that involve both government and industry that really haven't been confronted yet. One is the financing question and in what manner shall the respective governments provide the guarantees against the risks in this system and practically any proposal is going to be extremely controversial. Loan guarantees come -- again, raise the question that your socializing the private risk and letting the private owners have the profit, and there is going to be a lot of antagonism in both countries.

You may recall that the Diefenbaker government fell as a result of things resulting from the loan guarantees to the Trans-Canada pipeline. The -- so that -- it's a sensitive issue in Canada.

Another issue that hasn't yet become -- begun to be confronted which is relevant to this royalty gas sale, is how the gas is going to be allocated. If the -- if there is still wellhead price control by the FPC, every gas company in the United States is going to want some of that gas and no company can offer the producers or

the State of Alaska more favorable economic terms than any other company. So, there is going to be a lot more -- there is going to be a lot more demand for that gas than there is supply, assuming that some sort of viable pipeline system is hooked up.

The FPC is going to have to decide whose contracts are going to be approved. And even though there is no -- there is no current legal authority for the FPC to allocate gas and -- at least in non-emergency times among pipelines the way it can allocate today and say -- say to Columbia, "you know, Tenneco needs the gas more than you do, so we will turn down the Columbia contract in the -- the proposed contract with Columbia in the public interest because this other system is cut -- it's jeopardizing its number one and number two priority customers while you're still serving threes and fours." So, the FPC is going to decide who gets the gas. That is one of the reasons the producers aren't going out of their way to sign contracts, because -- you know, why should they choose one over another? They are not going to get any price advantage and the contracts -- a lot of them will probably be turned down anyway because the FPC wants somebody else to have the gas. Well, that hasn't yet been dealt with and if gas contracts are going to be used to finance the pipeline, then these have to be executed

before a final financial plan goes together. So, in summary, I don't see much chance for construction in -- beginning in '78 unless the U.S. and Canadian governments bite the bullet and say, "we will provide the interim financing and we'll guarantee the thing until you put the final -- until all the final arrangments are made." And I really don't see -- I don't see that. Maybe next winter, if the questions before Congress and the Parliament, and we have got another cold spell like this years, they'll be willing to do it. They may send the Corps of Engineers out to build the thing for all I know but -- but, I don't see it starting in '78.

SENATOR RADER: Senator Croft, were you through?

SENATOR CROFT: No, I have another question. To what extent do you feel that the assumption of the amount of gas that is available on the reserves in the Arctic, Prudhoe Bay, as well as the Mackenzie is an unrealistically high assumption? Both El Paso and Arctic are big volume lines. To what extent do you think their estimates of their potential build up of throughput are realistic or unrealistic?

DR. TUSSING: Well, if by the time -- by the time the system is completed, I think there is a good chance that there will be a lot more gas than we know about now. That isn't enough to get -- to get the kind of debt financing I'm

talking to. A good chance isn't enough. A good chance is enough to make a risk venture, but if you are risking your own money and you say "I think there is going to be plenty of gas there that we'll be -- that by the time the thing goes on stream we would be able to produce four and one-half bcf from those two areas and that's -- that's the way to average expectation and I'm willing to gamble my money on that." That's fine, but the bond -- the bond-holders want a ninety-nine percent assurance.

I think that there is merit to the notion that society, that is, that the U.S. and Canadian governments should take the risk and build a pipeline that is cheap to expand. Now, if the governments are not going to do it then the -- then the rationale -- the strategy of Alcan is the only one that makes sense. You put in absolutely minimum capital investment necessary to start that gas and that cash flowing. I think that they have -- that the Alcan people haven't scaled down their system as far as they could. That, for example, they could drop Northern Border out of the system and say, "we're going to -- we expect the NEB to authorize or compel Trans-Canada to move this east and then we'll take it through a Great Lakes pipeline and we'll increase the power or whatever is necessary there."

I think -- now, Judge Litt wants a western leg on

the Arctic pipeline and all the Western States want it because they don't believe that they will get the gas under reasonable prices by displacement. Well, the western leg is physically superfluous, at least up to, say one and one-half bcf going to -- going to western systems. Well, so -- so, as part of the political compromise you put the western leg into the system but you don't build it until after the gas starts flowing and the production builds up.

So, but if -- but if Canada and the United States are willing to bite the bullet and say, "our best geological assessment is that there is sixty or one hundred tcf up there which can be discovered within the next ten years, then let's go haul the hog, let's put in a high capacity pipeline. Let's put a MacKenzie link, whether it is on the Dempster Highway or the foothills or whatever as part of the phase two and build the thing so it is compatible with the Mackenzie link and so on."

SENATOR CROFT: What you are saying is that a sale of the gas will not have any effect on the route decision. What I was really getting at to get you to comment on, do you feel a -- (a) a refusal to sell any gas or (b) a refusal to allow production of gas might influence a route decision?

DR. TUSSING: No. There is no credibility to such a threat by Alaska because once the decision is made, the State's

got no -- the State's got no alternatives and all you do by not allowing the gas to be produced -- you may cause problems for oil production which causes the State a lot of problems and you forego the revenue. And, I just can't believe the State is stupid and spiteful enough to refuse to produce the gas just because the rest of the country didn't do -- didn't build the route the State wanted. It just doesn't make sense. And so that threat has absolutely no credibility. In the calculation of rates of return or costs assuming only seven-eighths of the production are just meaningless, you are just not going to do that and nobody will believe that you'll do that.

SENATOR CROFT: What about the holding down the rate of production?

DR. TUSSING: Well, there are some difficult -- there are some difficult problems. Suppose your reservior engineering studies show that the optimum rate of production is 1.6 bcf below -- is below the economic threshold of any pipeline system but that you -- but you do run into trouble by keeping injecting that gas and you're not going to flare it. You have some tough -- you have got some tough problems and I don't have an answer to that and let's hope we don't have to face that one. But, it is entirely plausible that you may have the level of production large enough to give you problems as to what to do with the gas,

but not large enough to make any transportation system viable. And, of course in the past what was done in that sort of situation is what is being done is Saudi Arabia and Venezuela and the other big isolated fields in the world, they just burn the stuff.

SENATOR CROFT: Mr. Chairman. If a one in ten chance which you referred to earlier is sufficient to keep investors from backing any gas line, isn't the uncertainty about levels of production such that it might -- that itself might cause a delay in the pipeline?

DR. TUSSING: Yes, I think so. The --

SENATOR CROFT: Particularly when it is coupled with the possible decision by the U.S. Government on deregulation which may make Alaska gas -- not only might they face a lower volume of Alaska gas but a less valuable Alaska gas, if you couple the two together.

DR. TUSSING: Yes, all of these are just parts of a big package of uncertainties that are going to cause difficulties for any of these proposals.

SENATOR CROFT: Thank you.

SENATOR RADER: Representative Gruening?

REP. GRUENING: Dr. Tussing, as I understand what you said earlier was that the Canadian government was going to make the choice as to whether it was for either Alcan or Arctic. How is the President going to feel comfortable

with making a decision, certifying a route without that stage in the negotiations being very certain? Are they going to amend the Alaska Natural Gas Transportation Act so he has more time? In other words, he has until July -- or September first and then ninety days if he wants to extend it. Is he going to feel comfortable with making that kind of decision without those things resolved?

DR. TUSSING: I think what he is going to do is as soon as the FPC decision comes down, and it may be happening right now, he is going to start talking with responsible Canadian authorities about -- oh, to what -- what kind of compatible decision we can come out with. And, I don't think that the Canadian authorities know what their political constraints are yet, until Berger has actually published his findings and there has been the -- a chance for a discussion of it and for the bureaucracy -- for them to read the FPC decision in the United States.

But, if the President makes the decision, say at the end of '77, you can count on its reflecting his discussions with the Canadians and he is not going to make a decision which is totally incompatible with what he thinks the Canadians are going to do. And both countries are going to bend over backwards not to appear to be forcing the hand of the other and to be blackmailing the other that there -- or leapfrogging or something like

that. They're going to try to make it -- they're going to try to come out with compatible decisions, whatever the --

REP. GRUENING: You seem to raise the same arguments that the El Paso people raise in terms of the unsolvable Canadian questions and I think, you know, the same statements seem to be made in terms of the problems. Now, are those problems going to be resolved to the extent that the President can make a decision certifying say a Canadian route and not -- coming back at a later time and say, "I'm sorry, we can't -- the Canadians just decided that they can't go either route, we're going to have to go to an El Paso --"

DR. TUSSING: Well, the law says that he has to make the decision whether or not Canada has -- he has to make a decision on its merits whether or not Canada has made a decision. And, irrespective of what the process in Canada is, in reality it's going to be a joint decision once the -- once the thing has gone through the regulatory and hearing phases of it and I don't know the exact mechanism by which the United States and Canada will consult on this. I'm sure no mechanism has been set up. But, it's not an insoluble problem, it's a problem whose answer -- whose outcome is impossible to predict with competence now. I don't think anybody can come out with

a solid prediction of what will happen in Canada, much less -- I'm as willing to do it as any Canadian. There is no authoritative -- there is nobody who has the authoritative position in Canada to say what Canada's position is on this. But, Canada will have a position of some sort and it will influence the President's decision.

I think that the -- that there is a good chance that the compromise between the FPC's decision in favor of Arctic and Justice Berger's decision against Arctic will be some kind of expanded Alcan system. That is my guess, but I wouldn't give it more than a fifty percent probability. One substantial possibility is that Canada will not authorize any pipeline or will postpone it till after the elections and the President may decide that we have to go ahead with our own system because of our internal needs, even though it's not -- even though it is the second best. So, my ability to forecast or prophecise is strictly limited on that.

SENATOR RADER: Representative Meekins?

REP. MEEKINS: Thank you, Mr. Chairman. Dr. Tussing, you stated in your comments that this contract, in your view, was not essential, that we weren't -- essentially that you weren't getting very much in the contract but looking at it from the other perspective, what are we losing, if anything? Are we losing anything by approving it?

DR. TUSSING: Well, it is -- it is conceivable that the Trans-Alaska route, or for that matter an Alcan route, after the State shifts to it, if it does, will be approved and that these contracts will be the basis of contracts under which gas actually flows.

I'm rather doubtful, even in this situation, whether the FPC will approve just these contracts for a number of reasons. But -- but it's possible you may be stuck with these terms and they are probably not -- not the best terms you could get in a bidding situation after the -- after the pipeline is -- route is clear. Certainly there may be opportunities in a deregulated situation to get a more favorable situation. I don't want -- I don't want to speculate too far on that, but your other consultants who have examined the contracts in detail point out ways in which the State has given up options. So -- So, in case they go into effect you have given it up. I do have one specific criticism of the contracts even starting -- even from the presumption -- the premises from which the administration is starting, that is, that you are going to buy some political support.

And, I don't know why you had to commit one hundred percent of the gas and I think there is some -- there are a couple reasons why you probably shouldn't commit one hundred percent of the gas. Firstly, you have this most

favored nation clause, that is, that the price is the highest price paid by any interstate purchaser. Now, it may well be possible for the State, if it kept some -- held some gas back to find a purchaser who would pay a higher price than any of the others and jack up the fate. If it kept some -- twenty-five percent out and waited until -- waited until the bidding process at the time of the completion of the pipeline, you might be able to get a higher price than any of the sales from the -- by the operators because the State might be in a position to sell to a nonjurisdictional purchaser, or to one that has a special tax advantage, like a state entity.

And, I would like to see you have the opportunity to use that twenty-five percent to jack up the price on the remaining seventy-five. Then the other is -- in the administration's presentation and within the whole rationale for the thing, there seems to be a high probability of a shift in route -- of a shift to Alcan, for example. And, if that is serious, if that is not just window dressing, then it would seem to me you would want to keep twenty-five percent out to -- and to offer it to Northwest at that time that the State moves to the Northwest position. Otherwise, the option of shifting doesn't seem terribly great. So, even if I were -- even if I accepted all the other premises, I don't see the reason for selling more

than three-quarters of the gas at this time.

SENATOR RADER: Representative Meekins?

REP. MEEKINS: Do you happen to know if that -- if the most favored nation provision, as you call it, in there would apply to sales to users? I'm not sure it would.

DR. TUSSING: I don't have it in front of me but if I recall the language, it's in any interstate sale. It doesn't -- or any interstate purchase and so it doesn't characterize the purchaser. It would seem to me it would -- frankly, I don't see why in a deregulated situation it should be limited to interstate sales since -- since, if the gas is worth Two Dollars in-state, to an in-state purchaser, you shouldn't sell it for One Dollar to an out-of-state purchaser.

But, as Mr. Moody says in his prepared statement, it may not be that you can get any contract which includes a -- you know, includes that -- all these provisions. That's a matter of judgment that is up to the negotiator, he really has --

REP. MEEKINS: Well, I'm trying to find out if there is anything we are really losing, in your view, in approving this contract. You know, we've heard that that -- that problem that you point out that we may be losing a higher price by not having reserved the twenty-five percent so we can jack up the most favored nation provision in there.

That might not be a realistic concern because the FPC wouldn't approve of such a contract anyway in their regulation of the transportation of such gas.

DR. TUSSING: Well, no. That's a -- that's one that depends on the -- it's conditional on deregulation. So, it wouldn't require an FPC approval. The FPC will continue to regulate the transportation and the transportation costs but if that's a feature of the wellhead price, conceivably the FPC could reject the whole contract on the grounds the pricing provisions are not in the public interest but I don't see that as a problem. I just -- let's say what you are giving up are the shortcomings identified by Mr. Swanson and Mr. Moody, as far as I can tell. That is, that there -- that you are giving up options or some possible options for getting a higher price by leaving the gas off the market until you see -- until all the circumstances are sorted out. You know -- for example, the amount the gas is worth to a particular gas distributor does depend on the transportation system. Now, the hierarchy -- the ranking and the order of preference of the different potential customers would change. For an Alcan system probably -- probably Northwest would be your preferred customer in a deregulated situation because the value of gas in its market is essentially the same as it is anywhere else in the country but it is

closer, so you have the lowest transportation costs. And, under the LNG system you would probably -- conceivably El Paso would be willing to bid the highest for two reasons. First, because it would be the point of off loading and be closest, and second, because they are quality problems. California probably has the highest premium but as you know, of course PG & E, which is one of El Paso's customers, is part of the Arctic group and would like to bring the stuff overland to California. Now I don't know how much PG & E would give.

REP. MEEKINS: Thank you.

SENATOR RADER: Mr. Chatterton?

REP. CHATTERTON: Mr. Chairman, Dr. Tussing, this is in effect the same question as Mr. Meekins -- Representative Meekins asked and I am going to ask it so I think that we can not be confused by rhetoric about pipeline routes and stay with just one subject, the contract, and I think you can answer it with a "yes" or "no". My question, do you believe that this legislature in approving these three gas sales contracts would be doing the people of Alaska a disservice?

DR. TUSSING: I can't answer that. That's a political question that really goes beyond my competence.

SENATOR RADER: Any further questions? We'll adjourn and subject to an adjournment by the House and Senate

tomorrow morning we will reconvene at 11:00 a.m.

We'll start with the Alcan people and go from Alcan to Arctic Gas and then probably through our consultants and then into the general public testimony.

We stand adjourned.

(Whereupon the hearing was adjourned at 5:15 p.m.)

FEBRUARY 4, 1977

SENATOR RADER: The joint hearings of the Alaska State Legislature relative to the sale of royalty gas will come to order.

We've been asked to announce that smoking in the courtroom is absolutely prohibited, and no beverages are permitted in the courtroom, or food either. I don't know if that's any problem, but if it is, be advised.

Today, as we announced yesterday, we're going to go first through our experts, the committee experts that have not yet testified. At the conclusion of that testimony we will consider further public testimony. I'll leave it up to the committee at that time to decide what they want to do, if they want to reopen public testimony at this time, or else request those members of the public who have not testified to submit their testimony independently to the Senate Finance, or Senate Resources Committee, or to the House Resources Committee.

This will be the last session of the joint hearings. Representative Gruening will hear from the Department of Resources and such others as the House determines, I guess next week or thereafter, at their pace; and the Senate will do the same, except that the Senate Committee will at least reconvene here at 10:00 o'clock Monday morning, primarily for the purposes of a

review and a rebuttal by our Department of Administration, Attorney General's office, and whatever, concerning misstatements that may have been made or positions that are unclear, and also submit themselves to questions by the committee members and, of course, other Senators on any questions of which we have reason to question their earlier statements or need clarification.

Representative Gruening, did you have any further announcements as to your committee?

REP. GRUENING: I guess not.

SENATOR RADER: We'll first take up Dr. Carl Swanson. Doctor, would you please identify yourself, give us a resume of your background, your position, and I would suggest that you go through your report and outline to us those portions of your report which you think are most important to us, and then open it up for questions. Would that be appropriate with you?

DR. SWANSON: That would be very appropriate. I have some remarks that I've outlined here which I'd like to give to summarize the report, as well as a few remarks on issues that have been raised during these hearings upon which I'd like to comment. Would that be appropriate for me to do?

SENATOR RADER: That would be appropriate. I'd like to have your background read into the record first.

DR. CARL SWANSON: My name is Carl Swanson, I am Executive Vice President of Jensen Associates, Inc., which is an economic consulting firm with offices in Boston, Washington and Geneva, Switzerland. The company specializes in economic analyses, forecasting, pricing, analysis of investments, advice on contracts, occasionally testimony before various Congressional regulatory bodies, or Legislative bodies, in matters of world oil, natural gas, natural gas liquids, and occasionally some work on electricity prices.

My educational background is at Massachusetts Institute of Technology where I received a Bachelors Degree in Economics and Engineering, and a PhD in Management. I taught for five years at the Sloan School of Management, at M.I.T. as an Assistant Professor. More recently I have been a consultant, since that time.

In my consulting, relevant to the issues that you face, I have assisted in the staff work, backing up, price negotiations on long-term LNG projects, I have performed analyses for computer simulation models of the logistics of moving LNG from the liquefaction line across the Atlantic Ocean to receiving terminals, into distribution systems, and to the burner tip. I have assisted industrial buyers under Order 533, analyzed supplies of natural gas and contracts that are offered to them. We have assisted

producers in analyzing their contracts, producers in analyzing their gas contracts, in order to see if they're well protected. I have looked at supply and demand of natural gas in the United States and impact upon curtailments. I have forecast the world-wide supply and demand to 1985 of propane and butane, that is liquefied petroleum gases, and lastly, relevant to your concerns my firm and I have analyzed the gaseous fuel markets in the states in the northeast quadrant of the United States in order to see the impact of price upon the demand for natural gas and for propane by industrial consumers.

That's my background, and I think what I'd like to do is briefly summarize the report which has been, I believe, distributed to the committee and is available to anyone else. Should I identify this report, Mr. Chairman?

SENATOR RADER: I would like to have the report made an exhibit in our proceedings. Would the reporter inform us as to the exhibit number.

MS. SANDERS: 16.

SENATOR RADER: Exhibit No. "16" will be the "Economic Analysis of Alaskan Royalty Gas Contracts" to the State of Alaska by Jensen Associates, Inc., consisting of some forty-four pages, dated January 1977. Therefore, any matter which the Doctor omits in his testimony will be available in the supplement, or in the exhibit. Would you proceed,

Doctor?

(Whereupon Exhibit "16" was duly marked.)

DR. SWANSON: First let me summarize the report. There is a summary of the report on the first four or five pages, which you may already have read, and I will essentially go through that summary.

Let me first, before I continue, identify who I'm representing. We were hired, Jensen Associates, Inc., were hired by the Legislative Affairs Agency on behalf of you ladies and gentlemen, the Legislature, to assist you in analyzing the contracts that you are now considering. Our mandate was to see if the contracts protect the interests of Alaska. We did not address ourselves to the legal issues; we confined ourselves to economic issues as appropriate to business ---

SENATOR RADER: Excuse me, Doctor, let me interrupt you. I do see some members of the Legislature, and I want to invite you to seat yourselves at the front tables here, if you would care to. It will be easier to participate in the questioning and also address the witness.

I'd ask, do we have a page. We're supposed to have a page here. When we get one I was going to ask the page to invite other legislators who may come in at a later time to come forward.

Proceed, Doctor, I'm sorry for the interruption.

DR. SWANSON: Thank you. We looked at this contract from two points of view, or we asked two questions. One question we asked was, if the El Paso project is not approved has the State preserved itself the right to protect its royalty gas and interest through provisions which allow it to terminate the contract. The answer to that question is yes.

The second question we asked is, if the El Paso project or any pipeline project which the Governor would like to support is approved, does this contract protect the economic interests of Alaska; that is, if this contract is in force is Alaska protected. We examined three different respects in which Alaska might be protected, and one of them is, can Alaska use the gas within its own state. Secondly we asked, are its interests in the natural gas liquids protected. Thirdly we asked, will Alaska, under the terms of this contract, receive a favorable price.

Let me take those questions in order. First, I think this contract has extremely well designed provisions to allow Alaska to reserve natural gas from Prudhoe Bay for its own use. The terms on reservations are unambiguous, and Alaska with what I consider to be short notice, two years, can take back to itself one hundred percent of the royalty gas.

Secondly, there is a provision in the contract which allows Alaska to exchange royalty gas for gas which may be more proximate to its markets and use the royalty gas, taking back the royalty gas in paper at least, in order to trade for gas which may be more available to it. This exchange provision provides a great deal of flexibility to the State of Alaska.

Thirdly, the provisions of the contract do not set any limit to when in the future the State could determine it will need the royalty gas which is in Prudhoe Bay. I interpret this to mean that the State could decide today or sometime when this contract is in force five years downstream gas which is currently being delivered, or part of the gas which is currently being delivered, would be needed in the future and thus Alaska, as I interpret this contract (and you probably should ask others about this) could at any time reduce deliveries to the purchasers. Now, since the Prudhoe Bay field has a gas cap, it would appear to me -- I am not a reservoir engineer and your reservoir engineers could comment on the reality of what I'm about to describe -- but it seems to me that Alaska could work out a deal with the producers to reduce slightly the production of gas from the gas cap and, in effect, store Alaska royalty gas for future years.

The second question we've addressed is, are the

rights of Alaska to the natural gas liquids well protected and the answer is, I think very well protected. Alaska has the right to extract ethane and heavier components at any time before or after delivery to the purchasers. I would interpret this to mean that if a gas processing plant were to be built in Canada or the United States and the liquids extracted there, that the rights of Alaska to the liquids would still be retained. I would suggest you ask Mr. Moody the same question.

Furthermore, within the contract, statements on quality of the gas of the contract, I saw no limitations to the btu content of the gas delivered to the consumers. To be sure, there is a price adjustment clause built in the contract for the btu content of the gas, but I believe there is no quality limitation to the delivery of methane or the natural gas which would restrict removal of liquids.

Third, I think the more important question and lengthier analysis in our report, is what price will Alaska receive for its royalty natural gas under the terms of this contract. I think in order to understand the terms of this contract as written I need to review for you very, very briefly what I believe to be the course of energy prices over the terms of this contract.

This contract has a term of twenty years, beginning upon initial deliveries of natural gas, which

will occur sometime close to 1985 very likely, meaning this contract will exist from sometime around 1985 to about 2005. As we look downstream at the price of energy in the world, I think most energy consultants agree that the Organization of Petroleum Exporting Countries is not likely to lose control of world oil pricing between now and 1985 certainly. I think most agree that the price of oil will continue to increase in world markets. I think the price of energy within the United States is going to rise more rapidly than the price of world oil, largely because at the current time the price of energy in the U.S. is controlled below world levels. As these controls are relaxed, particularly as more and more new oil, as it's defined in the regulations, is produced, and as more imported oil is brought into the United States, the oil prices should increase in the United States more rapidly than world oil prices.

Secondly, I think that it's very clear that there's a consensus developing in the United States that the conservation of energy is a very, very important national objective. There is yet no means that have proven to be effective by which this conservation is to occur.

Europe and Japan have imported oil in great quantities for many years, and they have very actively for many years used taxes to increase the price of energy

to their consumers in order to force conservation and this conservation, through the use of the price mechanism, has proved to be effective. I would expect the U.S. would begin to follow such policies of using prices to bring about conservation.

In sum then, I think that to 1985 we should within the U.S. and the world see increases in the price of energy. After 1985 we believe, Jensen Associates, Inc. believes, there is a very good likelihood, as long as industrialized nations do not fall into worldwide depression, that the production limits of the OPEC nations will begin to be strained by the demand for oil in the industrialized nations, and the chances after 1985 for very sharply rising prices will exist. Between now and 1985 we would expect oil prices to essentially track inflation in the industrialized nations.

This is the price scenario under which we need to examine the price terms of this contract; that is, prices rising gradually to 185 and with sharply rising financial prices thereafter.

The question is, do the price terms of this contract protect the interests of Alaska, its revenues essentially, with sharply rising prices after 1985. I think the people who framed the contract recognized that there is a fair amount of uncertainty about energy

prices, which there are, and they designed the contract to adapt to prices established outside the contract. There is not a price, there is not a set price, a certain number, in this contract for royalty gas. But prices are established within the contract under two different types of regulation that may occur in the future. One of them is deregulation.

If the price of natural gas at the wellhead is completely deregulated the terms of this contract, in my opinion, protect the interests of Alaska well. There is an annual redetermination clause which has been clarified by the purchasers as applying to both Section 6.3 and 6.4 within this contract, which will allow the contract to try prices on the North Slope of Alaska.

Now, the North Slope of Alaska is expected to be producing oil and gas in many other locations in the future. The terms of the deregulation clause in the contract allow the price to attract the highest price paid on the North Slope. One would expect that there will be continuing discoveries on the North Slope, and under deregulation continuing new fairly well market base pricing of natural gas which will be tracked by this contract.

Under deregulation this contract protects the revenues and the prices Alaska will receive for its

royalty gas in interstate commerce very well.

The second scenario one can view with a future is continued regulation of wellhead prices by the Federal Power Commission and possibly by Congress. The shape of that regulation is, hard for -- it's certainly hard for me to discern as regulation has changed from time to time with some fairly sharp shifts. Mr. Moody can explain that to you better than I can. We attempted to indicate it in our report.

But the contract does state clearly that Alaska will accept the regulated ceiling prices for the natural gas which the regulatory agency will set. It also says that the price that Alaska will receive for the gas will never exceed that price which the purchasers can include in their cost of service to their customer. This is the clause which protected purchasers. I would assume that the contract could not have been written without that clause in it. It essentially says that, given the very large volumes of gas which we're discussing in these contracts, that the purchasers will not have their shareholders pay part of the price of the gas if the regulatory agencies do not allow the full price of Alaskan royalty gas to pass to the consumers. I think it is probably likely that the purchasers would not have signed the contract without such protection for their shareholders

and their bankers.

Now, Alaska under regulation, you and anyone else who attempts to understand what the regulated price for gas will be from Alaska, will be faced with some difficulty, and that is because the recent national rate decisions from the Federal Power Commission have clearly excluded Alaska from the national rate, both in the application of a national rate and secondly, in the calculation of the proper national rate for new natural gas. Thus, it's not clear, the precedent is not clear the calculation of the procedures which will be applied under regulation if regulation persists to this North Slope royalty gas.

In our report we've attempted to show that there is a great deal of uncertainty, very significant uncertainty about what this price might be. In 1980 if the current pricing mechanism or the vintaging of 77-A, using the vintaging of 77, and I'm sorry if I'm using some terms with which you may not be familiar, the price which might apply to new natural gas, a Dollar Fifty-Six a million btu's. But Alaska has characteristics which are very different from the characteristics of the Lower 48 States in its gas production, and that is in the calculation of the national rate the calculation is based upon the costs of finding and developing non-associated gas. The reason for this is the Federal Power Commission has had a very

great difficulty in pricing associated natural gas because it had difficulty in allocating costs of drilling, exploration and development between oil and gas.

Thus, the Federal Power Commission, and there's an expert to my left and to your right who can describe it more fully than I the reasons behind it; the Federal Power Commission recently has said that the national rates for non-associated gas, and it simply said that the prices for associated gas will be equal to that calculated for non-associated gas.

Non-associated gas comprises perhaps seventy percent of the Lower 48 gas supply. Such is not true of Alaska. The Prudhoe Bay field is the largest field in North America and it has the predominance of the reserves of Alaska, and it's an associated gas field. If the Federal Power Commission were to apply cost based pricing to Alaska, particularly to the Prudhoe Bay field, you would have to face the issue of how to allocate the costs of drilling, development and exploration between the gas and the oil. The fact about the Prudhoe Bay field which is very delightful for Alaska in its sales of oil is that it is the largest field in the world. From the point of view of selling gas, if a rate were to be applied to Alaska, the fact that it's the largest field in the world may not give you the highest price because

the costs of finding and developing the gas per thousand cubic feet are relatively low.

We've calculated, using some very rough estimates, and ignoring the costs of water flood that may be attributed to the taking back of natural gas and the costs of extraction of carbon dioxide, that the Alaska rate might be somewhere between Twenty and Forty-Five Cents per million btu.

The question remains, however, does this contract protect your interests in your royalty gas, and I think that we can safety say this contract is not going to influence too greatly, with one exception (I'll talk about that in a second) the regulated price of natural gas. This contract can only adapt to prices set by the Federal Power Commission or other regulatory bodies.

Under regulation, the contract clearly states it will accept the regulated price (a), and (b) it says that it can receive a price no less than the price received by any working interest owner. Both clauses, I think, protect your interests reasonably well.

However, there is one concern we had, which we described in the report, which is that most royalty interest owners, and certainly working interest owners, are usually private investors. The State of Alaska is a body different from the private investor. It has social

responsibilities to its citizens.

One question that has been raised is, could Alaska under regulation claim, because of its unique responsibilities as a state, get a higher price for its royalty gas than the price given to the working interest owners. If such were true, this contract does not distinguish Alaska from the working interest owners, it clearly states it will accept that price which will be received by the working interest owners. I think you need to assess, and I would like to help you assess, the probability that Alaska might receive a higher price for royalty gas under regulation than working interest owners.

Let's do it in the following way. If Alaska were to state that it will ask for a price different from the working interest owners, and if Alaska were to ask for a higher price, I think the response could be a varied response. One response might be, and I'm sure there are some people who would make it within the courts and certainly before the Federal Power Commission, is that since Alaska has incurred no costs whatsoever in the discovery and production of its natural gas that if it wishes to separate itself from the working interest owners, it should accept prices based upon its costs, and its costs were zero. This would be unfavorable to Alaska.

The other possibility is that Alaska would claim it should receive a higher price for its gas because of its unique responsibilities to the State, to its current citizens and future generations. The likelihood of such an argument being accepted is one which I have difficulty judging. I think, however, that as we look at the decision of Administrative Law Judge Litt, he did not appear to have an attitude which would be favorable to giving the State of Alaska higher prices for its royalty gas than working interest owners were to receieve under regulation. You may wish to ask me some more questions about that point later.

Let me go on. One of the concerns of the contract that we had as we first read it was that since the State of Alaska does not collect severance taxes from itself that under regulation it might be possible for the purchasers to pay a price higher to the working interest owners, higher by the value of severance taxes, than the State of Alaska. I think the testimony certainly before these two committees by the purchasers was that right in the contract they did not intend to not pay an amount equal to severance taxes to the State of Alaska for royalty gas. Your legal staffs may need to judge whether or not you need to change your severance tax laws in order to insure that under litigation and under regulation, if

regulation occurs, if in fact Alaska will be able to accept a payment in lieu of certain taxes from the purchasers under its current law.

At this point I think I have finished my summary of the contract. The contract overall, I think, is a very good contract. It does protect the interests of Alaska. There has been one clause, which I've described earlier, about Alaska separating itself from working interest owners under regulation.

The thing, however, which is very clear in examining this contract and your sale of natural gas is that the provisions of this contract do not set a price for natural gas. The price of natural gas is going to be set by forces outside of this contract, perhaps market prices. More important, they're going to be set by regulation and legislation.

If Alaska wishes to return to itself favorable revenues for its royalty gas it should, we think, focus its attention more upon regulation and legislation than upon the terms of this contract. The terms of this contract will stand Alaska in good stead, but you need to deal with regulation and legislation in order to increase your revenues from the sale of royalty gas.

I would like to comment now on several issues, three issues, that came up during the course of these

hearings if it's appropriate to do so at this time, or would you like me to stop, Mr. Chairman, and entertain questions about our review of the contract?

SENATOR RADER: Why don't you go ahead and answer those questions that you think are pertinent and we will question you later on it.

DR. SWANSON: Thank you, sir. Several of the witnesses, including Natural Resources Commissioner Guy Martin, stated that, and I believe I quote Commissioner Martin, that very likely a higher price could have been attained in this contract for the royalty natural gas. I thought that was a very important statement that came out in his testimony. A number of other witnesses made the same statement.

I have asked myself can a higher price, in my judgment, be obtained than under the terms of this contract, and I must confess that I think it's highly unlikely. I think the pricing terms of this contract have been very well designed, again with that one proviso that I mentioned earlier. Let me review with you why I came to that conclusion.

I think, first of all, we must understand that royalty gas that Alaska has to sell now is 2.6 trillion feet; it's a large package of gas. I think it is possible in the future that Alaska could sell maybe a billion cubic

feet in a spot market for a higher price than you will get under this contract. But a billion cubic feet is not the same as 2.6 trillion cubic feet. It is possible, for example, under certain shortage conditions to receive a very high price, but not for the volumes of gas, I think, that you have here.

It has been suggested by some other witnesses that Alaska could have received a higher price for its gas had it sold gas directly to gas distributors and then had the gas transported by interstate pipelines, and that gas distributors would be willing to pay a higher price. I think Mr. Moody should discuss this with you more than me, but it is my impression of the Natural Gas Act that if a gas distributor in Boston or Chicago who is not now subject to the jurisdiction of the Federal Power Commission, if that person were to purchase gas in Alaska, move that gas across state lines and resell it in the Lower 48 states anywhere, that gas distributor would be subject to the jurisdiction of the Federal Power Administration. I think no gas distributor would subject himself to such regulation and thus would not purchase gas directly.

Secondly, it was stated that Alaska may be able to receive a higher price for gas if they were to sell it directly to an end user such as, I believe Pacific

Gas and Electric was mentioned, or large industrial consumers of gas. Again, I think Mr. Moody can comment on this with greater knowledge and with greater competence than I. It's my impression, however, the Federal Power Commission currently does not allow direct users of natural gas to transport gas through interstate gas lines for their own use except under Order Number 533. Order Number 533 is a very highly restrictive order which sets the term of any contract to two years and it says that only industrial high priority direct end users of gas may purchase the gas, and they may purchase the gas on a monthly basis, or perhaps on a daily basis, only to that extent of their high priority use is curtailed. Thus, when a winter is very cold and many home owners are burning a great deal of gas, such industrial purchasers could buy a great deal of gas. In warm winters such as we had in 1975 and '76, many industrial purchasers had their full needs of high priority gas met and thus they couldn't receive delivery of gas under direct purchase.

I don't think that any direct user of natural gas will be willing to sign the term of this contract, which says that they will take delivery as you receive delivery from the working interest owners, depending upon the gas production and upon the oil production, and pay for it because the timing of their needs for gas under

Section 533 is probably quite different from the timing of the delivery of gas from the working interest holders to Alaska and thus to your purchasers.

Secondly, let me address one other possible purchaser of your gas. It was suggested that an electric power and generation utility might be willing to purchase gas directly from you and burn it underneath its boilers. I am very, very doubtful if the Federal Power Commission would allow interstate transportation of gas to be burned, purchased in such a way, under boilers.

In fact, in some of its opinions on the purchase or the retention of gas by producers in the Gulf Coast to be used in refineries, the Federal Power Commission has very explicitly stated that gas may not be burned under boilers; in fact, it went beyond that. But I think it's unlikely that anyone who would burn gas under boilers can buy substantial quantities from Alaska or anyone else to be transported through interstate pipelines when high priority users in parts of the pipeline system in units are denied gas.

Let me go on to another issue. We have heard from two or three witnesses descriptions about the setting of price for natural gas under deregulation. The gist of their testimony has been that it's very difficult to set a price at the wellhead under deregulation. We have

been asked by a major pipeline and some liquids sellers to evaluate the industrial market for natural gas in the future in order to help them make investment decisions, in the case of one company in liquified natural gas and goal gasefication and another company in import problems.

So we have gone around, I personally have interviewed plant engineers, plant managers and energy buyers of large and small companies to ask them what price will they pay for natural gas. The price of natural gas will be set by the next buyer who will buy from the seller, the distribution company. If the seller, such as Boston Gas, is really selling to homes, the person, you and I, the home owner, will pay a higher price for natural gas to be burned in our furnace, to cook with, and heat hot water than will an industrial customer. However, if the quantity of natural gas delivered by a distributor is large enough so that he is delivering gas to industrial consumers, the price that that person can pay, that the distributor can pay, will be set by the next industrial customer that he can sell gas to.

In our interviews with industrial consumers of natural gas who were sometimes burning gas under their boilers but more often using the gas in their processes -- by process use of gas I mean the melting of glass, the keeping of glass warm as it moves into bottle making

machines or it moves from the annealing furnaces. The use of gas in annealing furnaces and metal working, the use of gas to heat metal for forging operations, the use of gas to dry the paint on automobiles, these are all processed high priority uses of gas.

In our review of the volumes of gas used in various locations and in the prices that these industrial consumers will pay for gas, we came to the very, very clear conclusion that there is more than enough gas in the United States, perhaps not well distributed, as we've seen this winter -- but there is more than enough gas in the United States to meet the needs of industrial consumers who are willing to pay from forty to sixy percent more per btu than they would have to pay for number two oil.

Also it is very clear that natural gas is a very easy fuel to handle, it's very clean burning fuel, it has flame characteristics which are easier to control in which one can use either fewer supervisory people or less skilled supervisory people to control the process such that industrial consumers will pay a premium for natural gas, five or ten percent, maybe fifteen percent in some cases, for process uses of natural gas.

We thus have concluded that, at least in the northeast quadrant of the U.S., which I might point out is

relatively short at the moment, that in the long run industrial consumers, many of whom have already converted to dual fuel firing of many of their pieces of equipment, will pay (to pick a number) ten percent more for natural gas than they will pay for number two oil. Consequently, when we, in our report, set prices that we believe under free market, under net back calculations, will be received by Alaska at the wellhead, what we asked is in 1980 and 1985 what will the price of number two oil be to the industrial consumer.

We've estimated those prices essentially by taking Arabian like oil, bringing it over to the United States with a transportation charge, moving it either through pipelines, or certainly through import terminals, moving it to a refinery close to the consumer, putting refinery margin on the number two oil and coming up with a price per million btu of number two oil, adding ten percent, and saying, "This is the competitive price for natural gas at this industrial consumer," and then netting back, subtracting the transportation costs to that industrial consumer back to the Alaskan wellhead to come up with some of our prices.

There have been witnesses before you who have argued that such a calculation that I've just described to you is inappropriate for determining the price of

natural gas, and they have argued that the so-called market competition incremental value pricing that I have just described to you doesn't apply because the Federal Power Commission and the State regulatory commissions allow new higher priced natural gas to be (so-called) rolled in or cost averaged with the lower priced, lower contractual, lower regulated price gas they receive such that even if the price of Alaskan gas delivered to a distribution company were to be higher than would be competitive before sold separately, because the higher price Alaskan gas (this is the theory) can be offset by lower controlled price gas from other parts of the Lower 48 States, that the distribution company could pay more than competitive prices for Alaskan gas, and still be able to sell its gas.

I understand the theory behind such an assertion, and the theory is a sound theory. And to be sure, today, in some fuels markets, propane specifically, where today prices of propane are controlled for some companies far below market values, those companies will go out and buy high priced propane, foreign propane, mix it in with their -- at least on their accounting bases, mix it in with their cheap domestic propane and they will be able to sell; they can pay a higher price for foreign propane.

But these purchases are a purchase of a shipload, and they'll sell the high priced propane within three months, purchase which may exist over a quarter, the next calendar three months. The contract we're talking about is a contract to purchasers of natural gas which will begin close to 1985 and will run for twenty years. So we really must look at the price of natural gas between year 1985 and year 2005 in order to estimate the applicability of so-called rolled in pricing to the distributors to allow Alaska to receive a very high price, a non-competitive, non-market based value price for its gas.

You should be reminded that other sources of natural gas, the distribution companies in the Lower 48, are such projects as coal gasefication, which is very high priced. A number of transmission companies are now importing liquefied natural gas. Some of the price escalation clauses in those importation contracts for liquefied natural gas, I believe, will generate some fairly high prices for that liquefied natural gas. And so on to rolled in pricing, the rolled in pricing of Alaskan royalty gas will not be based solely upon Lower 48 conventional production of natural gas, but will be based upon other alternate sources of natural gas.

I would submit that the rolled in pricing that

you are likely to receive will not be substantially higher than a competitive net back price computed, as we have done so in this report. Further, when I was assisting in the negotiations of the pricing clauses a long-term LNG import project, the clear position of at least the customers was that they would not pay a higher price for that LNG than would compete with two oil. They were unwilling to take the risk that either (a) rolled in pricing could not be applied to them or (b) that there would be sufficient amount of cheap conventionally produced low price controlled, low contract price controlled natural gas to offset higher than competitive price.

Thank you, I have finished. It turned out to be a very long statement.

SENATOR RADER: Representative Gruening.

REP. GRUENING: I have one question I would like to get answered. Is it your intention to start questioning now or after lunch?

SENATOR RADER: It is ten after 12:00. I assume that the committee would like to break for lunch and come back at 1:30. That seems to be the consensus; we will recess until 1:30.

(Whereupon the hearing recessed at 12:15 p.m. and reconvened at 1:30 p.m.)

SENATOR RADER: The committee will come to order. I would

like to ask the page to be certain to advise any Legislators that come in, they're welcome to seat themselves up forward here for more convenient questioning of witnesses and so forth -- and also to make certain that we enforce the "no smoking" rule in the courtroom.

We will continue, unless there is some objection, with the testimony of Dr. Carl Swanson. I believe we're in a situation for questions. Senator Gruening, did you wish to start off with that?

REP. GRUENING: I was waiting for the rest of the members to get here.

SENATOR HUBER: In that case can we take a five-minute recess, Mr. Chairman?

SENATOR RADER: I'm reluctant to do that because I'm afraid we're going to run out of time today. I'm just reluctant to do that, but I will wait so long as my Co-Chairman thinks it necessary for additional members to show.

SENATOR HUBER: I know Senator Butrovich is on his way.

SENATOR RADER: There are several routine matters that we can go through while we're waiting on other persons. We're going to conclude today the joint hearings. There will be additional testimony taken by the individual committees at their discretion at a later time, but the transcript of the record of these proceedings will be concluded today.

I am going to ask the reporter -- she has already been instructed to record some testimony out of order. Whenever such a request is made, I want her to clear that with Representative Gruening and myself. It's been asked that the expert's testimony, Dr. Tussing, be transcribed first and the other expert witnesses' testimony hired by the committee be transcribed in order of their presentation of testimony, then after that start at the beginning of the proceedings and go through them as they occur.

I'll want you to deliver -- the Department of Natural Resources will not be able to give their wrap-up testimony today, therefore, we will save the last exhibit number for them. Their testimony will be submitted in writing sometime next week. I will certify to it and deliver it to the reporter, she will append it to the original record and it will become a part of the official transcript of these proceedings.

After the document has been printed, I will ask the court reporter to certify one original copy for the House and deliver it to Senator Gruening, one for the Senate to be delivered to me, one for the Governor's office, one for the Attorney General's office, one for the Department of Natural Resources and one for each of the purchasers, to be delivered to such other persons

as they may designate in writing in a communication to my office. I will deliver them to them. Is there any further suggestion as to how to handle the record?

REP. GRUENING: It might be good to put the applicable statutes, the applicable statutes, someplace in the supplements to refer to as you read the testimony, if we could include it in the report. I have a stapled copy here that would cover the statutes that deal with the Royalty Board and surplus oil and gas.

SENATOR RADER: Then we will leave open two exhibits, one being the rebuttal and supplemental testimony of the Department of Natural Resources, and the second will be statutes, and I'll leave it up to Representative Gruening and the staff to submit the statutes that you want printed as an exhibit.

REP. GRUENING: I didn't realize you intended to include further testimony as part of the joint hearings, in which case maybe we ought to participate.

SENATOR RADER: Well, I think it's important that the Department of Natural Resources respond to some of the matters that have been raised and I was just going to let them respond in writing as an exhibit. I don't know what they're going to say.

REP. GRUENING: I see.

SENATOR RADER: Although we do intend to question them

personally, but our personal questioning of them Monday morning would not be a part of these hearings. But their written testimony, or their written response, if they care to make any as a part of these hearings, can merely be appended as an exhibit.

REP. GRUENING: We may show up Monday morning too.

SENATOR RADER: You're certainly welcome. We intend to go on at 10:00 o'clock.

SENATOR HUBER: Mr. Chairman.

SENATOR RADER: Yes, Senator Huber.

SENATOR HUBER: I notice from the assignment of the exhibit number 16 today, that that was the next number in line, and I note that the J. McCutcheon written testimony which I had requested be put in as an exhibit must not have got in because number 16 was the next in line. Would you please take care of that at this time, make sure that it appears as an exhibit?

SENATOR RADER: I think yesterday that we established that the secretary took the written statements of Mr. McCutcheon, that he submitted them to her and that she had intended, and does intend, to include his total statement as a part of the transcript of the verbal testimony. Is that not correct, Madam Reporter?

MRS. SANDERS: I believe that's correct.

SENATOR HUBER: We did deviate from it, Mr. Chairman, and

I wanted to make sure the written was in also.

SENATOR RADER: I just don't want you to type it twice. I observed yesterday during the testimony of Mr. McCutcheon, it was my observation that the reporter was not taking notes and, therefore, I assumed she was relying upon his statements and intended to include them in full as a part of the oral testimony given. Is that correct?

MRS. SANDERS: Yes.

SENATOR RADER: Mr. McCutcheon, does that satisfy you?

MR. McCUTCHEON: It wasn't my request.

SENATOR RADER: Senator Huber, does that satisfy you?

SENATOR HUBER: Yes.

SENATOR RADER: Then we will keep the exhibits numbered as we presently have it, with the Economic Analysis, the Jensen Report, as Exhibit No. 16, and Mr. McCutcheon's testimony will be, as I say, reproduced verbatim as a part of the verbatim transcript.

Should we proceed at this time? Any questions of Dr. Swanson? Representative Gruening.

REP. GRUENING: Dr. Swanson, the last couple days you've heard some concern expressed by the various members and Legislators as to the reason why the producers have not already entered into contracts, and various explanations have been given.

Judge Litt, in a report to the Commission in

April of 1976 attributed, at least to the producers, one of their reasons that they expressed to him for not entering into contracts, and I'm going to introduce this as an exhibit. It says, "They, the producers, expressed distress that the Commission has not yet embarked on a proceeding to establish a price for the gas and feared that an early sales contract would lock them into an adverse cutoff date under possible vintage pricing by the Commission, or the possibility of a deregulation statute being enacted by Congress." Now, would those concerns that the producers expressed to Judge Litt also apply to our entering into a contract at this time?

DR. SWANSON: The deregulation bills that have been introduced into the Congress normally deregulate new gas, and there's a definition for new gas. One of the definitions which has -- the definition that has existed in the Pearson-Benson Bill in the Senate and the Krueger Bill in the House, which were the deregulation bills which proceeded furthest in the past session, said new gas would be, among other things, gas which was dedicated to interstate commerce after some date.

Now, Mr. Moody is someone whom you should address the same question to, and I would defer to his knowledge and judgment. He is much more aware of the implications of the definitions of energy than I am. The impression

that I have left, that taken away from reading some of the bills, is that Alaskan gas which did not commence flowing in interstate commerce until sometime in '85 would be classified as new gas. But it's entirely possible that a bill could be introduced which has a different definition of vintaging. For example, the currently applicable opinion which sets the national rate, 77-A, defines new gas as gas flowing from wells which were spudded after January 1, I believe it's 1976, or '75.

Some of the wells which will be producing gas in Prudhoe Bay were spudded before that and would not qualify as new gas under a spud date definition of new gas. Under regulation, or under a deregulation bill everyone runs the risk that part or all of gas will not qualify as new gas.

Probably of greatest concern to this committee would be a definition of new gas which says new gas would be gas which flows into interstate commerce from contracts which are dated after some date which would be after the date of these contracts. Now, there is some precedent for contract dating, I believe. The applicable definition of new or old gas are set in vintaging.

REP. GRUENING: This may be what the producers then are

concerned about in their concern not to enter into contracts as of now.

DR. SWANSON: I would assume there are a number of questions that the producers had in their mind. There may well have been some questions about rolled in pricing versus non rolled in pricing. Certainly there were questions about vintaging, maybe some questions about deregulation. They were prepared, when they felt it to be in their economical advantage, to accept advance payments and to commit gas as they have in the past. Even though all of the same issues existed then, as they do now, they didn't. But those contracts, I do believe, did not set prices for the gas which will flow, even though they committed gas in their advance payments.

REP. GRUENING: Well, is it fair to assume that they're probably concerned about how the regulatory and legislative enactments affect pricing arrangements under the contract?

DR. SWANSON: I assume they are, and they may feel that they can exact a higher price if they wait, although I'm not sure that's the case. I think we should point out that the working interest owners have seven-eighths of the gas and the royalty interest is one-eighth of the gas. One of your concerns may be, if you commit now you will influence the price on the seven-eighths. I find that

dubious.

REP. GRUENING: That isn't -- really, my question goes to, should we not have the same concerns in terms of dealing with trying to write a contract which sets price terms now as opposed to waiting, as the producers seem to be waiting, until a time in the immediate future when pricing arrangements under the FPC and, perhaps, Congress will be more clear?

DR. SWANSON: I think the risks you run, the principal risk you run is if a deregulation bill or a definition of new gas or step price vintaging of gas were to use contract date as the applicable vintage date or new gas date. I am less qualified that Mr. Moody to describe issues of vintaging and the probability that contract date may become the applicable date of vintaging.

Another question that I think you raised was, does this contract fail to protect the interests of Alaska if the royalty gas committed under the contract is treated in the same vintage as working interest owners' gas. My reading of the provisions of the contract state both under regulation and under deregulation that the price of the royalty gas will be the highest price paid.

REP. GRUENING: Do you read that as meaning that vintaging, if I understand that term correctly, is not important for us to concern ourselves with? In other words, that concern

that I think the producers are expressing as to being thrown into a special category because they enter into a contract now doesn't apply to us, as a royalty owner.

DR. SWANSON: I think there is a concern. The degree to which it is a realistic concern or merely one of those very remote possibilities, I'm not able to judge except by citing some history. The real concern that you should have is the probability that vintaging will depend upon not the date of initial deliveries of gas into interstate commerce, but the date of the contract or the point the contract comes in force.

There is, in fact, in our report on page 29 a table listing ways in which gas can be defined, either vintaged or different ways in which gas is put into different price categories. In that table, and you may wish to ask some of the other witnesses about this table and its accuracy -- in this table a Permean base in Opinion 468 of August 1965 did use contract date as a method of vintaging gas.

In none of the recent national rate opinions nor the Krueger nor the Pearson, and this is the Pearson-Homes Bill, has contract date been, if I understand this correctly, an applicable vintage definition.

So we must go back fairly far in order to find contract date as applicable.

REP. GRUENING: I take it that it is possible there might be some disadvantage then if contract date became important as fixing a vintage on this gas?

DR. SWANSON: There is the possibility, yes.

REP. GRUENING: And what we're trying to establish here is just what we're losing by entering the contract, and the question I think that has been stated again and again is, aside from what we're trying to accomplish outside the pricing arrangements what could we be losing by entering a contract now as opposed to later since we're not actually at this time trying to get money for State revenue, we're trying to protect ourselves from any distadvantage by entering into this contract at this time. I think you said timing and price were very important.

DR. SWANSON: Yes. In my opening remarks, I felt that the State was well protected in this contract in the use of liquids, in the ability to reserve gas for in-state use, and I felt that the pricing provisions in the contract protected the interests of the State. I think you certainly have correctly identified a possible cost of the contract; that is, if vintaging in future FPC decisions or in possible deregulation bills or other bills in Congress use contract date as the applicable vintaging criteria, and contract date of this contract, and the date of break point in vintaging were to be between the

contract date of these royalty gas contracts and the working interest owners' contracts, that's a risk.

REP. GRUENING: The problem being an older vintage gets a lower price?

DR. SWANSCN: This has been historically true, yes.

REP. GRUENING: There are some other points the producers make in here. I'd like to introduce this as an exhibit. It's a report to the Commission by Judge Litt.

SENATOR RADER: All right. That will be Exhibit 17.

REP. GRUENING: This is my only copy of it.

SENATOR RADER: Report to the Commission by Judge Litt. And the date of it?

REP. GRUENING: April 27, 1976.

SENATOR RADER: April 27, 1976, and you will deliver a copy of that to the reporter, will you, Representative?

REP. GRUENING: Maybe she can make a copy for me.

SENATOR RADER: If you deliver the original to her she can give you a copy back.

(Whereupon Exhibit 17 was duly marked.)

SENATOR RADER: Representative Parr.

REP. PARR: Mr. Swanson, we have heard testimony that, as you know, the royalty gas price is tied to the price the producers get.

DR. SWANSON: Yes.

REP. PARR: We have heard testimony that it may well be that

the dollar price, let's say, shown on the producers' contracts may not be all they're really getting because they have tie-ins with some of the people to whom they will be selling and there may be, for example, a swap of some oil or gas, and other kinds of things that will not be directly a part of that contract and will not show a dollar value, but which obviously will have value to the producers. If that's true, do the contracts that we presently have, these contracts before us, protect our interests?

DR. SWANSON: I remember the testimony, I've forgotten who testified, as you just described. The concern you have, I believe, is under deregulation where there is somewhat market pricing that might apply. The reason I say that is, if regulation occurs probably the price will be held below market price, the price for Alaskan gas will be held below market price, and there would be no incentive for a producer on the North Slope to keep their prices below the regulated price, the allowable ceiling. So I think you're talking about a case which might exist under deregulation.

Now, on the North Slope or in the Prudhoe Bay area there are at least three major working interest owners, BP-SOHIO, Atlantic Richfield, and Exxon, plus some of the working interest owners are consortiums of

Amarada, Hess, and five, or six or seven different oil companies. Now, the contracts, under deregulation, in Section 6.3 and 6.4 clearly state that the redetermination shall be the highest price paid any working interest owner on the North Slope. It may well be, though I think the possibility remote, but it may well be that one working interest holder may have a somewhat lower price, stated price, in the contract under deregulation than would be justified by an arm's length not around the back deal.

However, in order that the highest price all be held down below market justified pricing would require at least six or seven oil companies to conspire to hold that price down. There are people who argue that the oil companies conspire frequently. It is my opinion that they compete vigorously. I doubt very much -- I think it highly improbable that six or seven oil companies of quite different size, who operate in very different areas of the world and very different areas of the United States, with very different crude balances and very different supplies of natural gas would find such a commonality of interest that they could even structure such a deal.

REP. PARR: I take it then, Dr. Swanson, that your answer to my question is, yes, the contracts do protect us.

DR. SWANSON: Yes, they do.

REP. PARR: Thank you.

SENATOR RADER: Any further questions? Senator Huber?

SENATOR HUBER: Thank you, Mr. Chairman. Mr. Swanson, are there any other reasons which you might be able to think of that the producers appear to have for not committing their gas at this time that might be worth the State's consideration before we commit ourselves, other than you have discussed already?

DR. SWANSON: I can't think of any at the moment. If I do think of one while I'm on the stand, would it be appropriate for me to so indicate and explain it to you?

SENATOR HUBER: Yes, I would appreciate that if you would.

SENATOR RADER: I had a couple questions, Doctor. You've attended the hearings since they commenced last Monday at 2:00 o'clock, is that not correct?

DR. SWANSON: Yes, I have been here all the time.

SENATOR RADER: You've been in constant attendance at all times?

DR. SWANSON: Yes, I have.

SENATOR RADER: Doctor, considering all of the testimony which you have heard and considering the difference between possibilities and probabilities, how would you characterize this contract as to whether or not it protects the State in an overall manner or does not the possibilities of it --

not as against the probabilities of it not -- in other words, I would like to have you use your expertise to help us weigh the value of very conflicting testimony and the statement of possibilities as against probabilities.

DR. SWANSON: In my opening remarks I attempted to deal with some of the issues that were raised in the testimony which precedes mine when I talked about the issue of, can a higher price be obtained than would be obtained under these contracts in the issue of pricing, royalty pricing.

It's my judgment that these are good contracts. I think that they protect the interests of the State in the use of liquids, in its ability to reserve gas and obtaining a favorable price. Very well, given the set of probable circumstances which may emerge in the future, and there is a great deal of uncertainty about the price of natural gas, to be sure, there is -- I think Representative Gruening has identified one possible event, that is the setting of vintage dates on contract date, which hasn't happened recently, which is a risk.

SENATOR RADER: Would you weigh that risk for us as possible, probable, improbable, or whatever terms you might choose to use? Again, it's very difficult for me to know whether that risk is something that is of such a nature that we should reject the contracts or how to weight it. In other words, place a value on this, recognizing again

that's really what you're hired for, is for your value judgment on matters in which we are not experts, on which there are conflicting possibilities and probabilities.

DR. SWANSON: I recognize that, and I think that's a valid question. You're asking me to evaluate probability of any legislative or regulatory event. Now, that is the using of contract date as the appropriate time for vintaging. If we look to recent history being in the last ten years, contract date was not used in such a way that the value of this contract to the State -- this contract compared to that with the State -- to be sure, the course of regulation and legislation is something which can be, particularly in the area of natural gas, can be highly unpredictable, as it has proven to be in the past two or three years. I would say that the chances that contract date will be used as a vintage date to the detriment of the State, if this contract were to be approved now, is probably less than fifty percent, and it may be quite a bit less than that. I'm not sure I've answered your question.

SENATOR RADER: Well, does it approach fifty percent? In other words, we signed this contract, we have a fifty/fifty chance of having signed a disadvantageous pricing contract because of vintaging.

DR. SWANSON: If I may just try to think through to myself

what the advantages to advocates of various positions and the position of the Congress might be of a contract date vintaging. Let me just pause a minute and think about it, and I will respond.

Senator Rader, I frankly don't understand the history or regulation well enough to know why a contract date was used in the Permean base in case, rate case for vintaging.

SENATOR RADER: Let me ask you this: I don't want to ask you to go on record here on something on which you are not prepared.

DR. SWANSON: I would like to continue, if I may, sir.

SENATOR RADER: All right.

DR. SWANSON: The reason for using vintages and defining something called new gas is to raise the price of gas to producers so that they are encouraged and have the financial resources to explore and develope natural gas.

The reason there is vintaging is to keep the price of flowing gas down, the theory being that one does not increase the incentive to a producer to find new gas by raising the price of old gas. That strikes one as a reasonable theory.

Both Mr. Moody and Mr. Byrd have done a good deal of natural gas contracting, but my understanding of natural gas contracts (you might want to pose this

same question to them) -- my understanding of natural gas contracts is that under contracts a whole reservoir, where all the natural gas under a lease will be dedicated to the sale, to the contract, often underneath the land area there will be more than one reservoir of natural gas, or often the reservoir may be sufficiently intimiable that after a while it makes sense to drill some additional wells, or it may be that in a natural gas lease, a natural gas reservoir, that after a while the well will sand up, the casing will collapse, or the well will be damaged, and thus a new well will have to be drilled; or if there is a deeper reservoir a well will have to be drilled or an old well re-entered in order to find the gas in a deeper reservoir.

If the vintaging date were the date of the contract -- remember that the whole, all of the gas underneath the lease, perhaps defined by depths, were to be dedicated to the contract, then there would be no incentive for the producer to repair the wells or to redrill the wells or to search deeper for new reservoirs. Thus, it strikes me -- the point I have is, and I guess you should ask other witnesses, is that given some of the conventions of natural gas contracting, that vintaging new gas by date of contract may impair the discovery of additional supplies of natural gas, which would be contrary to what

I understand to be the purpose of deregulation or the purpose of allowing a higher price for new gas, and thus self-defeating. If the theory I have just expounded is true, then I think that a vintaging gas generally within the United States by contract date would be unlikely.

SENATOR RADER: Any further questions? Senator Sumner.

SENATOR SUMNER: Mr. Chairman. Have you evaluated contracts between states and oil companies in the past?

DR. SWANSON: No, sir, I have not.

SENATOR SUMNER: Do you have any basis to compare or to answer a question of how does this contract for the sale of the royalty gas compare with the sale of royalty gas between other states and oil companies?

DR. SWANSON: I happen to have in my possession a very bad photographic copy of a sale of royalty gas from New Mexico to El Paso.

SENATOR SUMNER: How does this sale contract here compare in favor of the State?

DR. SWANSON: I read that contract last night, the one between the Royalty Board of New Mexico and El Paso, and I think that the sale of Alaskan royalty gas compares well. The other contract also was a soundly conceived contract, and it did not have the reservations clause that Alaska has.

SENATOR SUMNER: When you say compares well, is this contract better than, in your view?

DR. SWANSON: The contract you have negotiated is a better contract.

SENATOR SUMNER: There's some confusion in my mind. If the contract says that Alaska is going to get paid as high as any of the producers that are selling to the oil companies for the seven-eighths supply, would the vintaging determine the sale price that Alaska receives, or would the contract dates on their contract with the users or buyers determine the sale price that Alaska gets?

DR. SWANSON: I think you have posed a question which would require legal interpretation and, frankly, I had not thought of it, in response to the earlier questions of Senator Rader and Representative Gruening, because what you're arguing is that through the terms of this contract the vintaging date applicable to this contract alone may not apply. That's a very important question and I would only like to say that I'm not a lawyer, I do not have extensive Power Commission experience, and you have a witness who does. I just am not qualified to answer the question. I do understand the issue, and it's a good point.

SENATOR RADER: Let me go back just a moment then to the question I asked you. Does that change your answer to my

question as to whether or not it is likely in the future, in view of the past policies, that contract date will be the determining factor in vintaging? As I understood your testimony, you said you thought it would be highly unlikely the contract date would be the determining factor in vintaging.

DR. SWANSON: Unlikely, yes.

SENATOR RADER: Now, the question raised by Mr. Sumner does not affect your testimony in that regard, does it?

DR. SWANSON: No, it does not. In fact, if anything, it suggests that at least within the terms of the contract one does not know how those terms will be interpreted in accordance with the Federal Power Commission, at least within the terms of the contract, that there is even less likelihood that contract date vintaging would apply to the price.

SENATOR SUMNER: Mr. Chairman, in response to you, that's the view that I thought.

SENATOR RADER: Senator Colletta, do you have a question?

SENATOR COLLETTA: I believe Senator Huber did.

SENATOR RADER: Oh, Senator Huber.

SENATOR HUBER: I had on your subject in response to Senator Rader I want to get back in. Now there's a second one since you came in. Senator Rader and I apparently didn't hear exactly the same way. I thought I heard you say

that the chance that vintaging would be disadvantageous or that it would happen to the State was on the order of fifty percent, not very unlikely. So which way is it?

DR. SWANSON: Senator Huber, what I attempted to do was, when I said that the probability that vintaging would be based upon contract date, I said I thought the probability was less than fifty percent. I chose a number where I felt extraordinarily confident, and Senator Rader felt that, in his judgment, he needed a finer definition, a more precise statement of probabilities, and he pressed me on the point, and upon thinking about the point, in thinking about the use of contract date for setting vintaging dates for pricing, given the traditions of contracting in natural gas, did not strike me as too sensible, given the purposes of national policy in the use of vintaging. So I think that the probability that contract date will be the applicable vintage definition that dominates price under this contract is quite a bit less, it is unlikely.

SENATOR HUBER: Would you like to give a percentage of less than? You gave less than fifty before. Would you like to give us less than something now?

DR. SWANSON: Less than fifteen, less than ten percent.

SENAGOR HUBER: Less than ten percent. All right, that goes on ---

DR. SWANSON: Now, the difficulty of a number -- excuse me, Senator, I'm sorry.

SENATOR HUBER: Go ahead.

DR. SWANSON: The difficulty of a number given, such as that, is that it's a number which can assume greater importance, or it's an easy number to grab ahold of. You asked me the question straight, and I answered it as straight as I could. Maybe it's fifteen percent, maybe it's five percent, maybe it's ten percent, maybe it's two percent; I don't know, but I think when I state ten percent (maybe it's less) I think that's a fair characterization of unlikely. But remember that that ten percent would be further reduced by the point that Senator Sumner has brought up, which is that there are contract terms in the contract you are examining now which might make the vintaging which would allow working interest holders a higher price than applicable, but that's something presumably which will be worked out in the courts, and also it's something that requires legal judgment, which I would suggest you ask of Mr. Moody.

SENATOR HUBER: Mr. Chairman, that brings me to the second half of my question. Mr. Swanson, your definition that vintaging, I believe, was quite narrow here. In regard to that, have you taken into consideration the precedent that was set by the Federal Government action in disallowing

North Slope oil new status? Do you think that they might use vintaging or some other mechanism there to do the same thing with the gas that they have done with the oil that might affect the status of these contracts?

DR. SWANSON: There are two questions, I think, which we must address, and one question is, will these contracts approved now put the State in a worse position than if they were not approved, which is a very appropriate question, to be sure. My judgment is that these contracts are very good contracts and they do protect interests of the State, and that if they are approved now the chances that the State will suffer value are not great.

The second question arises, and I think it comes out of your point about the Federal Government, and that is, what are the risks to the State of Alaska of receiving very favorable value for its royalty gas and oil. Those risks are great, and I think they are legislative and regulatory risks, but by and large they lie outside of the contract.

SENATOR HUBER: Could I just draw you out a little more? You said there wasn't disadvantages to the contract. Could you conversely say , is there definitely advantages to the contract?

DR. SWANSON: The theory of examining the contract at this time, and many witnesses have testified to this, that by

approving these contracts at this time the likelihood of the El Paso project being approved will be enhanced. That's the theory. I, frankly, am not competent to judge.

SENATOR HUBER: And you don't want to make a judgment of how much enhance them being chosen over Arctic?

DR. SWANSON: No, sir, I'm not competent, and if I were to make a judgment I would be doing you a disservice.

SENATORY HUBER: Thank you, Mr. Swanson.

SENATOR RADER: Representative Gruening had a follow-up question.

REP. GRUENING: Are there any advantages to the State in terms of pricing in these contracts? Let's say if we do sell the gas at a later point under these contracts, have we gained anything in terms of pricing, setting aside the question of political gain that the contract is based on?

DR. SWANSON: It's very hard to be actually sure about what the course of events will be in the future. The contracts do state -- let me step back a second. The question is an important question and I must answer it.

Royalty gas comprises one-eighth of the gas in the Prudhoe Bay field. The contracts are very clear, that both under regulation and under deregulation that the price received by the State will be the highest price. The contracts are unambiguous. I do not believe that one-eighth interest is sufficiently large to swing the

value of the gas such that the prices received by the working interest owners will be less than if you waited.

For example, and let me expand on the point because I'm not sure I'm being very clear. If the amount of gas which you are selling now were enormous, more than enough to satisfy the demands in the Lower 48 States, then possibly by delaying, by not committing gas now and by having these highest prices for other people to obtain, you could depress future prices. But that's not the situation to be faced. The royalty gas interest is only one-eighth, and all of Prudhoe Bay gas, while very large, is not sufficient to solve the lack of natural gas supply in the Lower 48 States; so that your committee now does not so change the balance of supply and demand that future prices will be reduced by your commitment now. Have I answered your question?

SEN. GRUENING: If I interpret it correctly, you were saying that the contract protects us in most regards in your view, but in terms of advantages outside the political aspect of it, you don't see any -- it may be a good contract but you don't see any advantages to entering into a contract now as opposed to, say, trying to acquire these same terms at a future date, and that may be dependent upon whether, in your expert opinion, we could get these terms at a future date.

DR. SWANSON: You would require me to read the minds of the purchasing companies to determine if you could get the same terms that you have in these contracts at a future date. I have difficulty doing that. I would like to point to one section of the contract where you do have some very favorable terms, I think, and that is the purchasing companies have committed to pay the royalty share expenses upstream of the delivery point whether or not they are able to put those expenses into their costs of service. That's a good term, I think. Whether they'll agree to the same term in the future, I really don't know.

SENATOR RADER: Representative Chatterton.

REP. CHATTERTON: Thank you, Mr. Chairman. Dr. Swanson, I don't expect I'm going to ingratiate myself with you with this line of questions, but nothing personal is intended.

DR. SWANSON: You have an obligation, sir, a very important one.

REP. CHATTERTON: To bring everything into perspective, I have before me and have not a little slower than hastily read a November 30, 1976, letter addressed to Ms. Elke Kallab and signed by you, regarding a proposal to make an economic study of the gas sales contracts. That was dated November 30, 1976. And I also have before me a letter, or a document accepting your proposal that was

dated December 27, I believe, 1976, and unless you're like some people who may think that they're willing to commit course money to build a pipeline before you have a contract, I doubt if you started to do much work on this problem prior to the first of the year. I'm not questioning you as to the fact that in context of what you were asked for and what you have presented is, you've fulfilled the obligation completely, and I do concur with you, with slight exceptions of your findings, that this contract permits Alaska to recall and use the gas. It does have that, it does provide the LPG protection, but you did state here that in your proposal you would not involve an analysis of the sale of natural gas liquids, in your economic analysis, does provide for a favorable price. Now, I think it's equally important to this committee to know things that you did not find in arriving at this conclusion, and obviously within the framework of thirty days there's a bunch of things you did not find out.

DR. SWANSON: There's a very large number of things of concern to this committee that we did not state, that's correct.

REP. CHATTERTON: And possibly even the economic considerations, if you had studied these things, if we had paid you more money and you had had more time, it's possible -- it is possible, if you had studied possibly a trade in kind

of gas at Prudhoe Bay with like owned State gas someplace else, or State owned crude with like State owned crude someplace else, or looked to see if in any way this would be jeopardizing the ultimate recovery of hydrocarbons from the Arctic Slope, aiding and abetting the jeopardy thereof, is it possible you could have come up with a slightly different conclusion?

DR. SWANSON: Let me list for you a number of the things which perhaps are of concern which we did not study. I'm not a qualified reservoir engineer. Our firm are not qualified reservoir engineers. We did not study the question of the level of production of natural gas from Prudhoe Bay from the sedilogic sands which are appropriate. On the other hand, I would assume that, given the terms of the contract, that the State is well protected, if it were determined that to maximize the recovery of oil, gas production would need to be cut back, because this contract does not specify any minimum quantity of natural gas which must be delivered to the purchasers.

This contract does specify very clearly that the purchasers must pay for, whether or not they can pass on in their cost of service, the royalty share of facilities required prior to delivery. So I'm not really sure that our lack of knowledge of the specific reservoir characteristics

apply too much to our analysis of this contract.

We did not study, and I have no judgment of the relative merits of the three proposed gas lines, for example. A good deal of testimony has been presented here, and much more before the Federal Power Commission, on that issue, and perhaps you may, as individuals, in your judgment, in your decisions about this contract, weigh the relative merits of the three gas proposals. We have not examined them, and I have no opinion, no professional opinion on it.

We did not attempt to uncover for the State of Alaska other alternate buyers of royalty gas and attempt to understand from them the terms that they might be prepared to offer to you for the purchase of that royalty gas. I presume that in a sense the Administration, under Commissioner Martin, did explore with a variety of purchasers the royalty gas and possible alternate terms; we did not.

So the question you raised, Representative Chatterton, was, is it conceivable, is it remotely possible that our analysis would be altered had we spent more time and more effort in examining these contracts and the alternatives which are applicable to you. And when I was studying physics I read in a book that it's entirely possible, it is remotely possible that

all of the molecules of air in this room will suddenly rush over into that corner and we will all explode; I think that's remote.

In a contract such as this, one can over-study it. One should study to a point where one thinks one has a grasp and can offer sound judgment to a client. If we were to study, and study and study we would charge for that, and perhaps not give value for money received. I'm confident that our analysis is sound, our conclusions are sound; I can no more say that there is no possibility whatsoever of something possibly changing than I can that apples will fall up instead of down. Do I answer your question, sir?

REP. CHATTERTON: Yes, thank you very much.

SENATOR RADER: Senator Colletta.

SENATOR COLLETTA: Dr. Swanson, we have had a lot of talk about the possibility and probability of what could happen, and just taking the one aspect, the contract provisions (period), since you deal in that area what is, not the possibility but the probability of duplicating a contract verbatim to what is before us now if, in fact, we wait and see who builds what and when? I make specific reference to one section on the total take-back that we're allowed.

DR. SWANSON: The provisions for reserving natural gas in this

contract are favorable to the State. The reason that the purchasers signed this contract is, as I believe Mr. Tomas of Tenneco stated very clearly, that they frankly don't think that either (a) you're going to take back that much or (b) if you do take back that much they have a good deal of confidence that Alaska will experience a number of additional discoveries of gas and under the terms of this contract they can buy that gas.

Now, if you waited so long that it became more probable that Alaska would take back the gas or that additional discoveries would not be found and other discoveries were to be committed, then perhaps you couldn't get exactly the same terms with the reservation clause as in this contract. I think I'm grasping at something that is relatively small, and I think you may well be able to get reservation clauses in the future. As good as these? I don't really know.

The pricing provisions? I think in the future -- if you were to wait I think you probably will have pricing provisions which are as favorable as these. Whether the purchasers would pay for, at their own risk, the royalty share of the costs of gathering or whatever, I just simply do not know. I think likely they might; I don't know.

SENATOR RADER: Any further questions? Any questions on this side? We'll go a second round here. Senator Huber.

SENATOR HUBER: Thank you, Mr. Chairman. I'm sure that this question was asked of other people but it was not asked of Dr. Swanson, and I would like to know his answer.

I refer generally to the provisions in the contracts that head end money, premium money, whatever you want to call it, will not be allowed or will not be paid to the State, but that the highest unit field prices, in the language that we're both familiar with is there to state that, is used. Assume now that deregulation occurs, which apparently some form of deregulation is going to occur, and the working interests should negotiate large lump sum or front end payments with smaller amounts per mcf, wouldn't our contracts then have a good chance of denying the State the same opportunity for these much higher prices that might be paid, or likely would be paid, would be unlikely to be paid?

DR. SWANSON: Senator Huber, with your indulgence may I characterize what I think is concerning you and then see if I have characterized it correctly and then proceed from there?

SENATOR HUBER: Please do that.

DR. SWANSON: Would that be an appropriate way to proceed? I believe what you're suggesting is that the provisions

of this contract clearly state it shall be the highest price specified in some other contract, and that price will be in so many cents per mcf to the working interest owner. You were concerned, I believe, that potentially the value given in a contract or an interest owner may exceed the price stated in the contract, value being given to the working interest owner by an advance payment on an interest free loan.

SENATOR HUBER: Even if it's a separate document for advance payment.

DR. SWANSON: Or whatever, yes. I believe that is your concern.

SENATOR HUBER: That is my concern.

DR. SWANSON: We have the same concern in our analysis of this contract. Specifically we were aware of advance payments having been made for working interest holders of Alaskan gas. We then reviewed, as best we could, the outstanding advance payments, the ones that had not been terminated, advance payment premiums, so we uncovered, particularly the Columbia Gas advance payment agreement with, I guess it's BP and SOHIO. I'm not sure. And we asked exactly that question in our analysis. We addressed exactly that question in our analysis, would the price as quoted in the contract be lower because of a previous advance payment to a producer and, thus, not give full

value to the State.

Our research, looking at the contracts between SOHIO and Columbia led us to believe that the advance payments given to the producers would not reduce the price as quoted in the contract. That was the conclusion of our research.

Let me continue. One question that can be raised is, will advance payments be allowed in the future. I think the Federal Power Commission has suggested that they won't be. A pipeline will give an advance payment -- well, the Federal Power Commission says they're not doing it now -- a pipeline will give an advance payment only if it can somehow recover the cost of using that money or that money in its rate base. If they can't put it in their rate base or they can't somehow recover it from their consumers, they're unlikely to make advance payment, because they can recover an allowable price.

Secondly, in the repayment -- I would like to say something and I think I'm going beyond my current research and competence and I'm not sure whether I should say it, subject to verification of Mr. Moody or simply not say it. I'll proceed by your judgment.

SENATOR HUBER: If it's part of my question I wish that you would.

DR. SWANSON: I'll do that, but I do want to warn the two

committees that my recollection of the regulation of the law is shaky. My recollection is that the amount of gas that must be delivered for the repayment of an advance payment will depend upon the subsequently negotiated price for the gas. Thus, it is in the interest of the working interest owner to negotiate the highest possible price he can get in order to repay the advance payment as soon as he can.

If that theory or recollection were true, and you can check this with Mr. Moody, then the granting of an advance payment probably would not reduce the stated price in the gas sales contract and, thus, would not provide full value under the most favored nations clauses or the clause of deregulation in them, and in the highest price clauses under this contract.

SENATOR HUBER: Thank you, Mr. Chairman. I feel it is a little better given, the answer, from our experts rather than the oil company in this case on that one. I lay that one to rest as far as I'm concerned.

SENATOR RADER: Any further questions of Mr. Swanson? Mr. Swanson, I think you were trying to catch an airplane, were you, this afternoon?

DR. SWANSON: No, sir, I'm going to catch the 8:30 plane out tonight, so I'm at your service.

SENATOR RADER: Would you stay for the remainder of the

proceedings in case questions do come up later?

DR. SWANSON: Yes, sir.

SENATOR RADER: Thank you very much. I have no particular preference of order myself. Mr. Moody, Dr. Kilgore, do you gentlemen have any idea as to a preference of testimony, your order?

MR. MOODY: Whatever the will of the committee, Mr. Chairman.

SENATOR RADER: Why don't we take a ten-minute break and let me discuss with both of you the nature of your testimony and make a decision?

(Whereupon the hearing recessed at 2:40 p.m. and reconvened at 2:50 p.m.)

SENATOR RADER: The committee will come to order. During recess I discussed with Mr. Moody and the Doctor the order of testimony, and it was the feeling that the Doctor's testimony would be more in line and more relevant to that which has gone immediately preceding and, therefore, it would be logically easier for him to testify at this time along the same lines as indicated previously by Dr. Swanson.

Doctor, of course, you're an old hand here. We all know that you're with the Levy Lipton Associates, but for the record, for those who do not know you, and who may come across this record, would you give us a full statement of your firm and yourself, and then proceed

with the statement, which I presume then we would open to questions.

MR. KILGORE: All right, thank you, Senator. My name is Richard Kilgore. I'm Director of Research for W. J. Levy Consultants Corporation. Our firm has been economic advisor on matters of oil and gas to the Legislature since, I believe, 1969. We are also consultants to a number of oil companies, domestic and foreign, small and large. We also are consultants to a number of chemical companies on feed stock procurement and feed stock availability and so on. We're also consultants to a number of major oil users such as electric utilities, mining companies and the like. In addition to the State of Alaska, we are consultants to a number of other governments, at the present time the Province of Alberta, for example, and Pertamina, the state oil company of Indonesia, among others.

As for myself, I'm an economist by training, a Bachelors Degree in Economics from Rutgers University, and a Masters Degree from Carnegie Mellon University. Senator, you've been calling me Doctor; that is incorrect. I'm one of those who passed Ph.D. exams and never wrote a thesis, so I would like to correct that.

I've been with W. J. Levy since 1963, just about fourteen years now. Prior to that I spent two years with the National Bureau of Economic Research, which is a major non-profit research organization. I was also with the

Econometric Institute for a short while, and also did some work for the Committee for Economic Development.

I would like to make what I hope are relatively brief opening remarks, and they really have to do with how we, as your economic advisors, view what you're trying to achieve through these contracts. At least my opening remarks today are addressed primarily to the underlying reasons for sale of Prudhoe Bay royalty gas.

I'm going to cover such things as what are the interests of the State of Alaska, what issues can Alaska properly decide for itself; set against these, what are the broader national interests; and how do Alaska's interests fit into the national decision making process on this gas pipeline. And we'll try to put these in the context of the contracts before you.

As I said, my initial remarks will have relatively little to say about the contracts themselves. As an opening statement, our view can be characterized this way: if Alaska decides that sale of royalty gas is essential to support of an all Alaska pipeline route, we feel that the contracts, in general, are carefully conceived to protect the State's interests.

The primary objective in entering into agreements for sale of Prudhoe Bay royalty gas at this time is to provide support for an all Alaska route. We would like

to review briefly the reasons for Alaska's interest in that route and the importance of these reasons. As we see it, there are basically two types of benefits to the State in an all Alaska route. First, there appear to be certain fairly clear-cut economic benefits, although probably offset to some extent by some social costs.

And second, there is the question of the potential availability of gas for State use with the El Paso route.

We would like to provide some perspectives on both of these potential advantages. Among the pipeline alternatives there are certain economic advantages to the State that can be reasonably established. These were reviewed by the Governor's Task Force, and then the report, Comparative Evaluation of Prudhoe Bay Natural Gas Pipeline Systems.

An all Alaska route, together with its liquefaction facility, does appear to provide the greatest economic advantages in certain key areas. Employment is an obvious one; resulting income flows to Alaska's labor force, although all these will obviously not be State residents, there will be migrants too. Employment and income should be higher, both in the construction and operating phases of the El Paso facility, as against others. The greater length of the line, and the LNG facility virtually insure this will be the case.

Tax revenues to the State treasury should also be higher, largely through the operation of your property tax. Again, it's the greater length of the line and the LNG facility that make this possible for you.

Now, another major source of State revenue from Prudhoe Bay natural gas will be royalties and severance tax, both of which are based on wellhead values, as you know. The Governor's Task Force concluded that these revenues would not be affected by alternative routings; that is, that higher or lower transport costs to markets would not bear on wellhead values.

Now, we agree that as long as sales of Alaskan gas in interstate markets continue to be regulated by the Federal Power Commission, this is likely to be the case; that is, that wellhead values will probably be established on a basis other than a net-back from markets, that transportation would probably be added on to a regulated wellhead price, and the final price would be rolled into the final cost of gas to distribution companies and to ultimate consumers.

The FPC staff, I believe, has recommended the rolling in of high-cost gas supplies such as foreign LNG and Alaskan Arctic gas, and I understand that Judge Litt has also recommended this approach for high cost sources.

Under deregulation this is not necessarily the case, that the costs of transportation would not bear on prices. Transport costs, in that case, would have an ultimate bearing probably on the value of Prudhoe Bay resources. But we basically feel that deregulation is not a too likely event for some years to come.

We would caution, however, that Alaska cannot always assume that the value of its resources will be unaffected by the routing of its exports. In the long-run this may be the case. I think Prudhoe Bay provides a current example of some of the problems of transportation costs on wellhead value. As you know, there is a problem of potential crude surpluses on the West Coast, the major market to which Prudhoe Bay crude will move. And there is a possibility that some volumes of Alaskan crude may have to move to quite distant markets, that is, beyond the West Coast, around to the Gulf and East Coast of the United States, and this would be at very high tanker transportation costs since the oil must move in U.S. flag vessels and the distances are very substantial.

And if this is the case, if Alaskan crude does move in this direction in any kind of substantial volumes, there will inevitably be a question of the value of Alaskan crude in Alaska; that is, what market is its value established in. We feel that over the long-run it is not

in the national interest, and probably not in Alaska's interests either if its wellhead values are affected, to funnel ever larger and larger volumes of Alaskan energy supplies through California; that is, larger and larger volumes beyond Alyeska crude and beyond the El Paso route, if that is chosen.

If major oil reserves are found in Petroleum Reserve No. 4 on the North Slope, for example, a strong case will be made for a pipeline to move that oil through Canada I think, despite the fact that you have a pipeline corridor southward. Incidentally, if the gas Arctic pipeline is not built and an oil line moves in that direction, it would then be pioneering a corridor rather than following a corridor which might be established had the gas Arctic pipeline been constructed.

But this is somewhat aside. We believe it is reasonable to assume that the value of Prudhoe Bay gas will most likely be unaffected by the cost of alternative pipeline routes, at least for many years ahead. And let me also say that we've looked at the various studies that have been made on the costs of transportation, what the FPC has done, what other people have done, and we are not entirely certain in our own minds which system would, in fact, have the highest cost of transportation. It looks like a very uncertain thing to us. A lot of the

cost estimates are based on probabilities of delays, cost over-runs and so forth, that are very, very difficult to assess, in our view.

Against positive advantages in terms of employment, income and tax revenues, there are other factors to be considered as well by the State; and, as the Governor's Task Force concluded, some of these may be negative to the State in an all Alaska routing if one looks at such things as social impacts, the effect on the cost of living, prices in Alaska, and so on, and also looking at environmental factors which are, obviously, very difficult to assess. The all Alaska route also involves an LNG facility, movement of LNG tankers out of Alaska, and these pose new environmental concerns, and ones we feel are very, very difficult to assess.

However, these are all factors that the State and its citizens must evaluate and weigh with the more clear-cut economic advantages from taxes, employment and so on. Your own Task Force concluded that the positive advantages outweighed the negatives, as you know.

The second reason for supporting an all Alaska route is the potential availability of natural gas for in-state use, and it is very clear -- I've been through all the -- I've sat also through all the hearings -- it is very clear from your questions that many of you

consider that aspect very vital.

It is obvious that the potential availability of gas is quite different among the three pipeline alternatives. El Paso moves to tidewater, and this could be very important for uses of gas in industries which involve export of their products to Lower 48 markets, obviously; being on the water, near water transportation, is important.

Alcan, of course, moves gas to Fairbanks and then moves off in a southeasterly direction, and in directions which run through areas that are, obviously, not very populated.

Gas Arctic route, of course, provides gas essentially just on the North Slope.

It is difficult, however, to assess how much value to be placed on this greater potential availability of gas for in-state use. We should point out first that there may well be other gas availabile in the State over the years ahead. Exploration is beginning now in other areas, the Gulf of Alaska, Lower Cook Inlet, Bristol Bay and so on. Gas may be discovered in one or more of those areas, and it is possible also that gas may be available for in-state uses from these areas at lower costs, lower transport costs and the like.

As an aside, I think we should also mention

something that we have before, that to the extent that the State of Alaska feels that in-state use of gas is very important to it or may be important to it in the future, they might consider in their leasing policy, perhaps changing leases so that what they have available to them, to the State, is not simply a royalty which can be taken either in value in kind. Perhaps the State should consider some sorts of options in leases which provides the State's future ability to buy back gas if the State feels that's necessary. This is not what is under your consideration now, but I think I should say again one should consider this if use of gas, you feel, is important in your State.

In any event, all may not be lost in terms of future availability of gas if the Gas Arctic route is chosen. As for now, however, it is Prudhoe Bay gas that is becoming available, and other potential supplies are obviously very speculative. And El Paso clearly has the potential to make more gas available to more locations in the State of Alaska. But what then really are the advantages in using gas within the State of Alaska?

You have major oil resources in the state, as you all know, and you're obviously not an energy short region. I believe we've pointed this out before, but we would

like to again: there is likely to be an economic advantage to using gas versus oil in an area such as Alaska, which is a major exporter of energy and also an exporter which is remote from its major markets. The reasons for this is that the economics of transportation clearly favor movement of oil over gas.

Gas transport costs per btu are roughly three to four times that for oil when the gas is moving overland by pipeline. Gas transport costs are roughly ten to fifteen times higher when the gas is transported over water as against transportation of crude oil over water. Thus gas, which carries very high transport costs, tends to have a lower value in an area such as Alaska, an exporting area such as Alaska; and oil, a higher value.

In general then, the economics tend to favor use of gas in Alaska and export of oil. To put it another way, gas is a better btu bargain locally, oil a better product to sell nationally. But we want to caution you and point out that gas transportation within Alaska is also, obviously, expensive if distances are very great over which gas must move; it's possible that the general economic advantage of using gas internally could be wiped out. But in general, the distances that you're likely to move gas to markets are likely to be comparatively short, at least as compared with the distances

you would be moving it to export markets in the Lower 48. Thus, in general, we would expect that gas will be a relatively attractive fuel for use in the State, as against oil.

While there can be significant cost advantages to using gas in Alaska, the potential volumes that might actually be consumed, we believe, are very elusive. We've looked at a number of studie that have been done projecting these volumes, and we think it is by no means certain that the volumes would be very large, especially any time in the near future.

It is even difficult to estimate what future residential, commercial and conventional industrial fuel uses might be in Alaska. Realistically, as I said, we believe that the volumes are not likely to be very, very large. We would note that in the Anchorage area where gas has been available for many years, as you know, and which is the area's most populous region, Alaskan consumers are now consuming something like two hundred million cubic feet a day of natural gas. Your royalty share of Prudhoe Bay gas might be on the order of three hundred million cubic feet a day, or about fifty percent more than is currently being consumed in Anchorage, where it has been available for many years, and where a large part of your population lives.

Now, new industries are possible. Copper, iron ore, nickel were pointed out by the Governor's Task Force, but they also were very candid in admitting that, and I quote, "At the present time there have been no large-scale, serious and detailed proposals by the private sector to utilize Prudhoe Bay gas for in-state use."

Non-conventional uses of gas, and we've heard some testimony about these, such things as using gas as a feed stock for petrochemicals or for methanol are even more uncertain, we believe. If these do materialize it seems likely that it would be many years down the road. While the resources are available in Alaska for these types of operations, the economics of scale and of transport of products to other areas tend not to favor Alaska and tend to work against the economics of these industries in Alaska. We don't mean to say nothing of this sort will ever come about, but what we are saying is that one has to look very carefully at the economics of these things, and it is uncertain, quite uncertain as to what volumes would be used in the foreseeable future for these unconventional uses.

So, as we see it, the State's interest in an all Alaska route depends on, first, reasonably clear-cut net economic and social benefits; second, the potential

availability of gas for in-state use which, in principle, could provide economic advantages as against other fuels, notably oil. But the volumes that might be used, and their importance, is very difficult to judge and uncertain.

But it is up to the State and its people to decide how important these factors are to their interests, and how vigorously, and by what means it wishes to pursue these interests. We do not, however, feel that the State of Alaska can really be the judge of what pipeline route is in the best overall national intersts. There are a great many factors that bear on this beyond the interests of the State. Alaskans should be aware that other routes than an all Alaska route might have greater overall advantages to the Nation.

On the other hand, if Alaska feels strongly about what it sees are important advantages to the State in the all Alaska route, what is important is that these interests are considered and weighed in the national decision making process that is now taking place as to the routing of the pipeline.

We were struck, in reading the FPC staff report, which strongly recommended the Gas Arctic route, that the interests of Alaska and potential benefits to the State were apparently not really considered at all. Judge Litt,

in his decision, and I haven't read it all, I haven't read it in its entirety, acknowledges that -- and again I quote, "Alaska's views are entitled to substantial weight." However, I suspect that he is not as convinced of the validity of Alaska's arguments and gives them less weight than most Alaskans might wish.

If Alaska feels strongly about what it believes are the interests of the State in an all Alaska gas pipeline, it will want to work to insure that its views get a very careful hearing in the nation's decision-making process. The sale of Alaska's state royalty gas is one way of attempting to do this. If this approach is chosen, we believe that the contracts before you are, in general, as I said before, carefully conceived and effective in protecting the State's interests.

We are not legal advisors to the State, I want to caution, and we have no legal expertise, and there are others here who do. But I would like to make the following general comments on the contracts.

Some questions have been raised about the pricing provisions, and you will obviously have to consider these very carefully. You obviously are by the nature of your questions. In the end, it seems to me, you will have to assess the likelihood of these contingencies that are spoken about; that is, the likelihood that the State

might be able to get a higher price if it didn't sign this contract. Various alternatives have been thrown out. Some of them seem to involve sales of emergency gas to industrial users, questions of whether the State would be caught on a vintaging problem if it signed the contract now, and get a lower price, and so on. From your questions it's obvious also that you are taking the approach that we would recommend, trying to assess what the possibilities of these things happening are. I'm sure you're going to ask me more questions on this.

In general, I've looked at these possibilities; I think they're relatively unlikely. And second, if you conclude that these things are possible, that is that it's possible that the State might get a lower price by entering this contract, and even if you assume that that possibility is very small, you might want to consider how could one protect oneself against this possibility. You'll have to ask yourself, could you write contract terms or modify this contract in a way which would protect you from these eventualities. Well, I don't know whether I have the answer to this, but I suspect it's probably doubtful that you could. I think there are probably other witnesses who may be able to give you a better answer to that.

Now, as to the other provisions, the recall

provisions seem to us to be very strong. It is difficult for us to see how they really could be improved upon very significantly.

We are also pleased with the State's ability to get access to liquids under the contract. We have always felt that liquids could be very important to the State, if not as a petrochemical, or a feed stock, or for methanol, or something rather exotic, we think that they could be especially of value as a fuel to local residents, especially to businesses and residents in remote areas. So that we feel that liquids, in the end, could perhaps be of even more benefit to the State for in-state use than gas itself. It's a possibility, and we're very pleased with the provisions of the contract in that respect.

In sum, the Legislature will have to consider carefully what its interests are and how to pursue those interests. In the end, only you can decide whether the contracts before you are an effective mechanism for achieving your objectives. Thank you.

SENATOR RADER: Thank you, Mr. Kilgore. Any questions? Mr. Gruening.

REP. GRUENING: Mr. Kilgore, when you mentioned studies that you looked at for in-state use of royalty gas, which studies were they?

MR. KILGORE: Well, there was one prepared by your Division of Natural Resources.

REP. GRUENING: Could you identify it specifically?

MR. KILGORE: I think I have it with me. "Analysis of Prudhoe Bay Royalty Natural Gas Demand & The Proposed Prudhoe Bay Royalty Natural Gas Sale" dated January 1977. It's a study done by the State of Alaska, Department of Natural Resources, Division of Minerals and Energy Management.

Now, I don't want my remarks to be construed to mean I quarrel with this study. It's very difficult, all I'm saying -- estimating future requirements is an extremely difficult and uncertain thing, and this may be as good a job as can be done, but the results are still highly uncertain.

REP. GRUENING: Did you do an analysis of what projected uses might be?

MR. KILGORE: No, we have not.

REP. GRUENING: In that regard, the testimony yesterday from Mr. Thomas Stahr was that the Anchorage utility saw that in 1985 their needs in Cook Inlet would be exhausted. In your readings or studies have you established that to be true?

MR. KILGORE: No, I really don't know whether that is true. I do not know how much gas is committed to that pipeline.

REP. GRUENING: But the major part of that would be that two hundred million cubic feet per day that you referred to that's used there?

MR. KILGORE: Yes, a significant part of that does go for generating electricity in the Anchorage area.

REP. GRUENING: And the total royalty share at peak capacity is about two hundred-fifty to three hundred million cubic feet per day?

MR. KILGORE: I said very roughly three hundred million cubic feet a day. That's an eighth of 2.4 million cubic feet a day, a very rough number.

REP. GRUENING: Did you run across a date at which at least the present known reserves at Cook Inlet are exhausted?

MR. KILGORE: No, I haven't. The gas reserves data are available. The American Gas Association has estimates of reserves in the area.

REP. GRUENING: Do you recall whether that study of January '77 covers that point?

MR. KILGORE: No, I don't recall. As I recall, it was basically an anlysis of potential gas demands along the route of the pipeline.

REP. GRUENING: But it didn't take in total the gas demand in the State?

MR. KILGORE: I believe not.

REP. GRUENING: Are you familiar with the provision that

allows the companies that are purchasing to take one and a half times new reserves that are discovered to replace gas that we call back?

MR. KILGORE: Yes.

REP. GRUENING: Do you see any economic disadvantage to the State in doing that? It was raised, I think by Mr. Dallas, yesterday . He pointed out that, say, reserves were found in Cook Inlet, new reserves or, say, Copper River Basin, that we would be giving them lower priced gas. In other words, because of the lower transportation costs we would be giving them gas at a lower price than we should.

MR. KILGORE: Well, frankly, I don't know the answer to that. As I originally read the contract I thought it referred to gas which traversed the whole length of the pipeline, that this was gas they would have a call on. I was thinking in terms of North Slope new discoveries or more gas on the North Slope. I really don't know the answer to that question.

SENATOR RADER: Representative Parr.

REP. PARR: Mr. Kilgore, you mentioned a while ago that one of the possibilities was gas from OCS, you mentioned the Gulf of Alaska, etc.

MR. KILGORE: Yes.

REP. PARR: And that this might be cheaper than what we could

get from the North Slope actually. As you know, of course, the Supreme Court has held that all belongs to the Federal Government and we don't have a claim on it. So I suppose we would have to buy it from the producers. Even considering the fact that we would be buying it rather than using our own royalty gas, do you think the economics are still such that we would do better by taking OCS gas, assuming it is produced in reasonable quantities?

MR. KILGORE: I think the answer to that is very uncertain. It's impossible to really know. One doesn't know the pricing of this gas, one doesn't know the physical circumstances under which it would be produced, what sort of costs would be involved in bringing it to shore and so on. I think the answer is, one cannot really determine in advance whether that gas would be cheaper. It could be.

REP. PARR: Is it also possible, Mr. Kilgore, that the Federal Power Commission could decide where the OCS gas would go, it might say it would all go to Pennsylvania rather than staying in Alaska at all?

MR. KILGORE: Yes.

REP. PARR: Thank you, Mr. Kilgore.

MR. KIGORE: Certainly.

REP. PARR: Two different points. You said a while ago it didn't seem really that there was too good a potential

at least at the present for use in the State of the gas. At least it seemed to be highly doubtful as far as you were concerned.

MR. KILGORE: What I said was, it's very uncertain, it's elusive, and we suspect that the volumes would not be too large.

REP. PARR: Does that mean what you're saying is that you don't anticipate, at least in the foreseeable future, a sufficient demand; is that what you're saying; or are you simply saying you can't tell? I'm not sure.

MR. KILGORE: What we're saying, it's very difficult to tell. If you want a judgment, I suspect it's lower volumes rather than higher volumes.

REP. PARR: Has your company ever done any kind of a study as to the lowest economic threshold at which petrochemical plants and so forth will become feasible, of the kind that might be built, let's say, in Alaska using the royalty gas?

MR. KILGORE: No, we have not made formal studies of that. We know some of the problems of the economics involved and so forth, but we have not done a formal -- this is from broad knowledge chemicals and so on. It is not from a detailed study of the potentials for petrochemical uses in Alaska.

REP. PARR: Could we assume that the use of natural gas in

other communities in Alaska would be roughly comparable to that being used in Anchorage? I'm not talking absolute terms, of course, but in, say, relationship to the population? Fairbanks, for example, is roughly -- the Fairbanks immediate area is roughly one-third the size of Anchorage. Now, do we anticipate that they would use about one-third as much as Anchorage, or does that vary quite a bit?

MR. KILGORE: I think, if one has to make a guess, you might guess that it might be lower per capita. Don't forget, Anchorage is a populated area, you have a density of population, and this provides advantages, economics of scale of putting in distribution systems and things of this sort. If you were going to put gas into Fairbanks there would be a very, very high expense of putting in a distribution system. If you look at other more remote areas, the economics of just getting it there and the scale of population, or the users in those areas, is quite small and tends to work against the advantage of gas use.

REP. PARR: That was going to be my next question. You did say, I believe, something about the possibility of using, I believe, butane and propane, which are the liquids from the natural gas, especially for remote areas. One thing you really didn't touch on very much was the

liquids. You said you thought it was desirable to the State to have them. Do you have any idea of the economic feasibility of taking liquids out in the State, let's say propane and butane, and shipping those to remote areas of the State to use?

MR. KILGORE: Some liquids, obviously, have to come out, I guess there's been testimony here. On the North Slope there will be some taken out for pipeline reasons. The answer is no, we have not done detailed studies on the economics of the use of propane as a fuel in areas. The statements I made really come from our broad judgment and from our knowledge of the industry, not from detailed studies.

REP. PARR: Thank you, sir.

SENATOR RADER: Representative Hayes.

REP. HAYES: Mr. Kilgore, yesterday Mr. Thompson of the Alcan Pipeline testified that in his opinion one of the advantages of the Alcan route over the El Paso route was an approximately Eight Hundred Million Dollars of additional revenue to the State. From your testimony I conclude that you don't agree with this, and if my conclusion is correct is that because you don't agree with their projected construction costs or you don't agree with his statement that if construction cost is less it will result in a better price to wellhead?

MR. KILGORE: It's the latter. I don't quarrel with his or anybody else's construction costs because I don't have my own estimates. What I'm saying, we really don't know what the circumstances of pricing of Prudhoe Bay gas are going to be. If it's still regulated by the Federal Power Commission we don't know quite how they're going to regulate it. We don't know whether there will be regulation and so on.

We think the most likely thing is that we will have continued wellhead gas regulation by the Federal Power Commission and that it will set prices independently of what the transportation costs are. That's the most likely thing to happen.

If you're looking down the road and we really have deregulation, then the cost of transportation could have an impact on the value of gas at Prudhoe Bay.

REP. HAYES: If I might continue on that, we have had testimony here that we can expect deregulation of some sort down the line. Would you agree with that?

MR. KILGORE: Well, if far down the line is a very long period of time, yes, I think you can't rule it out. We think it unlikely it would come anywhere in the near term.

REP. HAYES: Anytime during the life of the contract?

MR. KILGORE: The life of the contract is?

REP. HAYES: Twenty years.

MR. KILGORE: Twenty years. Well, near the end of the contract I suppose the probabilities get higher.

REP. HAYES: But in any event, in your opinion, you don't anticipate any regulation that would be beneficial to the wellhead price in the next ten years.

MR. KILGORE: I think that's most likely, there will not be.

SENATOR RADER: Senator Sumner.

SENATOR SUMNER: My concerns lie primarily in the area, say, of economic development potential, whichever line is chosen. Which line, in your view, would provide more economic development opportunities for the State of Alaska?

MR. KILGORE: Well, I think the all Alaska; I think that's reasonably clear.

SENATOR SUMNER: Do you think that petrochemical manufacturing is a potentially viable interest for our future?

MR. KILGORE: I think it may be. I don't know at the present. I think it might be and I think obviously this is something you want to look at. You will want to get people, chemical companies who do this kind of thing to look at it very, very carefully for you. I don't want to imply, anything that I've said, that you shouldn't pursue economic development.

SENATOR SUMNER: There seemed to be some doubt in your mind

as to whether it might not be feasible, and yet the primary interest in using the Alcan line, or the all Alaska line, would be for that primary benefit. Yet you seem to have a fair amount of hesitancy as to whether that's ---

MR. KILGORE: I think this is something that you're obviously interested in. I guess, yes -- what I'm really saying is I wouldn't overdo my expectations as to what you will get because you have gas available.

SENATOR SUMNER: If we don't get the all Alaska line what opportunity in the future do you see where there might be a possibility of getting gas to tidewater or an Alaska line bringing the gas down?

MR. KILGORE: Is your question where else one might get gas?

SENATOR SUMNER: What is the opportunity of getting gas to tidewater in the future if we don't get the Alaska line that's proposed?

MR. KILGORE: That depends on what the chances are of finding gas in the area close to tidewater, and there are a number of prospective areas where gas could be found. But there isn't anyone, including myself, I'm not a geologist, but one who really knows geology, who can tell you for sure exactly what the probabilities are of finding gas in these areas because there has been, as you know, virtually no exploratory work in many of these areas. So you just

can't assess in advance how much you might get or what the chances are.

SENATOR SUMNER: Are you aware of any interest at the moment from different chemical companies that might have an interest in Alaska in the petrochemical area?

MR. KILGORE: No specific knowledge. In the past -- as I say, we have some chemical company clients -- we have very broadly suggested they might want to look into this possibility. But I don't know of any detailed proposals of looks at the present time.

SENATOR SUMNER: And if I've drawn the right conclusions, you're saying that the Arctic line provides virtually no economic benefit or development benefit for the State of Alaska except money; the all Alaska line provides the most opportunity of the three lines; is that correct?

MR. KILGORE: In terms of economic advantage and potential availability of gas.

SENATOR SUMNER: Thank you very much.

SENATOR RADER: Senator Butrovich.

SENATOR BUTROVICH: Mr. Kilgore, in your work for the State, have you people projected changes in population down the road?

MR. KILGORE: No, we have not, Senator. We have not been asked to do that.

SENATOR BUTROVICH: Are you aware of what is happening in the

way of population in Alaska?

MR. KILGORE: I know that it's growing rapidly, yes.

SENATOR BUTROVICH: Can you see any difference in shipping a product by water, say, from an Alaska port to the South 48 than from Alaska to Japan or from South America to the United States?

MR. KILGORE: Well, obviously the costs of transportation depend upon the distances involved, but in the case of Alaskan shipments to the Lower 48, they also involve the use of U.S. flag vessels, which are considerably higher on cost than foreign flag vessels. Shipments from Alaska, for example, to Japan would not have to move in U. S. Flag vessels.

SENATOR BUTROVICH: You are aware, however, I assume, or are you aware that when the consumer in Alaska buys something he is generally paying the freight up and the freight back because of the fact that there is no back haul?

MR. KILGORE: Yes, sir.

SENATOR BUTROVICH: Wouldn't you consider the possibility of a petrochemical industry in Alaska greatly reducing that span of cost to the people living up here if, indeed, there was a back haul?

MR. KILGORE: Yes. I think it's obviously something you have to look at. It's an important objective for you to pursue. You see a problem and you obviously should

pursue it. The problem may be that -- I said may be -- certain types of chemical processing, you're talking about a plant on a very large scale, and a very small part of the output of that plant may be consumed locally in Alaska, which means that a very large part of the output may have to go to other markets, and you have to look very carefully at how competitive that big part that goes elsewhere is with supplies from other sources. I don't want to prejudge the answer.

SENATOR BUTROVICH: No, I'm sure you don't. It's awfully hard for me to reconcile, in this day and age, why it is not as practical to ship by water from Alaska as it is to ship by water anywhere else. There's no such thing anymore anywhere that I know of where such a thing as cheap labor exists. That used to be a great argument, but it certainly doesn't exist in the United States today. I, for one, don't think that enough emphasis and enough study has been developed on the petrochemical side of this question.

MR. KILGORE: I would agree with that.

SENATOR RADER: Senator Huber.

SENATOR HUBER: Mr. Chairman, I do have a couple. Dick, do you believe that the contracts that we have before us are attractive enough to disregard the earlier admonitions of Walter Levy and Milt Lipton to be very

cautious about committing our future oil and gas supplies before delivery systems actually exist that are able to transport them? We've heard that many times from Milt and Walter, and can you expound on it?

MR. KILGORE: I think, as a general proposition, I would probably agree with that, but what one has to do is -- here you have a new objective, something else which you are trying to do with these contracts. You obviously have a purpose for doing it; it's to help promote a line which you seem to be quite interested in having, and you just have to assess that against a more general position that perhaps waiting is better. You really have to assess the value of it.

SENATOR HUBER: Leading to my next question, Dick. Do you believe the contracts will decide which route is chosen, and would you please try to give us a percentage of chance for El Paso against Artic Gas, for instance?

MR. KILGORE: Senator, I'm really not able to give you that kind -- it obviously provides some positive support. I really don't know what the odds of it are. I think that's beyond the scope of my competence as an economic advisor.

SENATOR HUBER: My last question fits in with it. Leaving political considerations aside, if you remove the political considerations from the contracts, do you believe

we could get more money if we held off selling our gas until a transportation system is ready instead of using it for political clout? If so, what magnitude would you project?

MR. KILGORE: As I said before, we don't really know what future pricing is going to be like. We don't know whether it's going to be regulated pricing, or deregulation and so on. So there is an uncertain future. It has been suggested there is at least a possibility that the State could get a higher price by not signing this contract and waiting. But when I look at the circumstances under which this possibility might happen, I think it's unlikely.

SENATOR HUBER: You think it's not the most likely scenario?

MR. KILGORE: That's correct.

SENATOR HUBER: Thank you, Mr. Chairman.

SENATOR RADER: Any further questions? Mr. Chatterton? It's about time for a break. I assume we're just about. through with this witness, but go ahead.

REP. CHATTERTON: There are three questions, and I don't know how long he's going to take to answer them.

SENATOR RADER: Why don't you go ahead, let's try it.

REP. CHATTERTON: Sir, Mr. Kilgore, let's take an assumption that here last week there was a natural gas transportation system between Prudhoe Bay and the South 48 and, at least

we will take that premise right now. Now, apparently a crisis occurred in the northeastern sector of the United States that has led the President to take near national emergency situations, at least for transporting liquefied methane between American ports in foreign bottoms and Heaven knows what all we are doing, quite an upset. On the premise that that straw existed, do you believe that the President might even have been able to legally, and I'm sure he would have, demanded Alaska gas from Prudhoe Bay even though it might have made the people of Alaska suffer?

MR. KILGORE: Yes, I think it's a possibility. In an emergency situation you can't rule out that if he doesn't have the power now that the Congress will legislate such powers.

REP. CHATTERTON: Without that straw he can't do much about it, can he?

MR. KILGORE: No, there's no way he can move the gas to the Lower 48.

REP. CHATTERTON: You indicated, when you were giving your reasons for being hired by the Legislature here and so forth and so on, that you did do consulting work for, I think you said, transmission companies, other foreign governments. I don't know whether I singled out of context transmission companies, but would any time,

keeping in mind the powers of the Alaska Oil and Gas Conservation Commission, would you recommend to a client or do you think that a client, even if you recommended that he proceed to look for financing, could possibly get financing for a Six to Nine Billion Dollar pipeline in view of the powers of the Alaska Oil and Gas Conservation Committee?

MR. KILGORE: What your're asking, are these powers likely to be an important stumbling block to ---

REP. CHATTERTON: To the financing.

MR. KILGORE: To the financing? No. I think those powers, in and of themselves, no.

REP. CHATTERTON: Even though they can turn the valve and shut the gas off in two years?

MR. KILGORE: I think if the lenders were reasonably assured from their own looks and so forth at the reserves and so forth, and carefully considered what they felt were reasonable flows of gas without loss of pressure and so on, without loss of oil, I think they would go ahead, yes.

REP. CHATTERTON: You, yourself, or your associates have not so done, have you -- made that determination?

MR. KILGORE: No. We are purely economic consultants.

REP. CHATTERTON: One more question and I'll close. Do you think, by any chance, that the transmission system between

Prudhoe Bay and the South 48 would be financed by public money?

MR. KILGORE: Do I think is there a possibility that in the end public money or some sorts of guarantees, or something?

REP. CHATTERTON: Yes.

MR. KILGORE: I think there is a possibility, yes.

REP. CHATTERTON: Thank you, sir. Thank you, Mr. Chairman.

SENATOR RADER: Representative Hayes.

REP. HAYES: Thank you, Senator Rader. I want to get back on the question that I was asking you about, the timing for deregulation. I didn't quite pose the question correctly. I think you said that you didn't think there would be deregulation in the next ten years, but within somewhere between ten and twenty years from now. The contract actually starts on the date of delivery, isn't that correct?

MR. KILGORE: Yes.

REP. HAYES: So that during the first ten years of the life of the contract we might expect deregulation, going back to your previous answer?

MR. KILGORE: It's possible, yes.

REP. HAYES: Thank you.

SENATOR RADER: Any further questions?

SENATOR HUBER: I have a short one that comes from a question Mr. Chatterton asked.

SENATOR RADER: Go ahead, sir.

SENATOR HUBER: I just wondered, Dick, I thought maybe you might have some idea. Well, here's the question. How much is the reasonable flow of gas without reducing oil recovery? That's in answer to the way you used it in answering Mr. Chatterton.

MR. KILGORE: Would you repeat that, Senator?

SENATOR HUBER: In your opinion, how much is the reasonable flow of gas without reducing oil recovery in the content that you used it in answering Mr. Chatterton's question?

MR. KILGORE: As I said, I'm not an engineer, I don't know technically the answer to that. My answer to the question was, if the lenders and other people in their own analysis were assured of this fact that they probably would be willing to go ahead. I have no opinion of my own as to what the volumes would be.

SENATOR HUBER: I thought it indicated to me you had some knowledge that we didn't have, from your work with other companies.

MR. KILGORE: No, sir.

SENATOR RADER: I think you stated, Mr. Kilgore, when you started, that you've been in attendance constantly during the hearings which started Monday, and that the value judgments you have given us today, you have taken into consideration the testimony that you have heard

at these hearings thus far?

MR. KILGORE: Yes, Senator.

SENATOR RADER: Are there any other questions of Mr. Kilgore? Mr. Kilgore, will you be available the rest of the afternoon?

MR. KILGORE: Yes.

SENATOR RADER: We'd appreciate it very much if you could keep yourself available for the committee if they have any questions.

MR. KILGORE: I intend to. I'll be happy to do so.

SENATOR RADER: We'll take a break and then hear from Mr. Rush Moody. Ten minutes.

(Whereupon the hearing recessed at 3:45 p.m. and reconvened at 4:00 p.m.)

SENATOR RADER: The committee will come back to order. Mr. Jerry McCutcheon has handed me a two-page document dated April 4, which he has asked to be inserted into the record as an extension of his remarks as Exhibit 18 instead of requiring him to verbally testify. Unless there is objection, we will have those remarks placed in the record as Exhibit 18.

REP. CHATTERTON: Objection. Would you change the date to February 4, please, from April 4?

SENATOR RADER: I'm sorry, did I say April 4? It's February 4.

(Whereupon Exhibit 18 was duly marked.)

Our next witness -- before he starts to give us his own statement of qualifications, I just thought I might direct the attention of the people present, as well as for the record, that the February 7, 1977 Newsweek entitled "The Gas Crisis" in the National Affairs section, Mr. Rush Moody, a former Federal Power Commissioner, is extensively quoted. So I want you to know that Mr. Rush Moody has a national audience for sure and perhaps a national constituency. I don't know about that.

MR. MOODY: If nominated, I will not run.

SENATOR RADER: But, at any rate, I want to say one thing about the Alaska Legislature; we go first-class when we hire consultants. That's February 7, 1977 on page twenty.

Mr. Moody, would you please -- as many of you know, Mr. Moody was first retained by the State of Alaska last year by the Joint House-Senate Gas Impact Pipeline Committee, which was a statutory committee chaired by myself and Representative Gruening as Co-Chairman. Mr. Moody gave that committee extensive testimony last year on some of the same matters that we're considering now. The committee went out of existence as of January 1 of this year, the statutory committee. As I say, he was retained by that committee, as was Mr. Swanson,

from funds appropriated to that committee, with the thought that some committee of this Legislature would need his advice and his counsel in this matter.

So, Mr. Moody, with that, would you please read into the record first, sir, your background qualifications, and then I assume you will make a statement and open yourself for questions.

MR. MOODY: Thank you, Mr. Chairman, to both Chairmen, and to the Members of the Committee, I wish to express my appreciation for the opportunity of being here. I have been most impressed over the course of the past five days with the attention and the concern which each of you expressed. I wish that the Congress of the United States would take as seriously some of the problems they have as you obviously take seriously this problem before you.

I am a lawyer by trade. I attended the University of Texas, with a Bachelor of Business Administration, University of Texas Law School, licensed to practice in the State of Texas in '56, in private practice from 1956 until 1971. I was appointed to the Federal Power Commission as a Democratic member by a Republican President. I served on the Federal Power Commission from 1971 until March 15, 1975. I was Vice-Chairman of the Commission for two of those years.

I resigned from the Commission in March of 1975 because of my belief that the structure of Federal regulation was injuring the consuming public of the United States and that very serious regulatory reform was necessary if the country wasn't going to get in a lot worse shape than it was already in.

Following my resignation I represented the

Governor of the State of Texas in Washington, as his special counsel on energy affairs. In January of 1976 I became a managing partner of the Washington office of the law firm of Vinson and Elkins. The firm, of which I am a member, has offices in Houston, Washington, Fort Worth and London.

I hesitate to claim to be an expert in any area, but I am more than fifty miles from home and I do have a briefcase, so I guess I qualify.

Mr. Chairman, I would start out, I suppose, by saying that I attempted to prepare for the committees a summary of the contracts together with some analyses, or attempted analyses, of what I perceive to be the major strengths and major weaknesses.

SENATOR RADER: Let me interrupt you, Mr. Moody, so we be sure we don't miss that. Make certain that the remarks, your analyses and your covering letter of January 28 is entered in full as an exhibit to the hearings, and that would be Exhibit 19; is that not correct, Reporter?

MRS. SANDERS: Yes.

SENATOR RADER: Be assured that your full remarks are in the supplement.

(Whereupon Exhibit 19 was duly marked.)

MR. MOODY: Thank you, Mr. Chairman. I realized after I got here and after I listened to the course of the

hearings over the past several days that, in many instances, the issues that were being explored related to whether or not any contract should be signed, whether it was appropriate use of the State's resources to commit to these contracts, these particular purchasers, under these particular circumstances at this particular time.

I will, if I might, go through the more formal part of my contract analysis first and then turn, if it is the committee's will, to some of the other issues that have been addressed during the course of the hearing, and then finally respond to whatever questions the committee will have.

With respect to the contracts themselves, I should start out by saying that it is very difficult to make a comparison with any other gas sales contract because you have a unique situation, and much of what I can offer to you, other than with reference to the technical side of the contract in terms of measurement, metering, and that sort of thing, I can tell you whether that's standard or whether it's not standard. But there's much that's in the contracts that reflect the unique nature of the transaction, and so when I offer thoughts on that I hope that you gentlemen and ladies will understand I'm having to offer you value judgments of a sort. I didn't perceive it to be my job to say this is the best of all

arrangements that could be made, but rather to take what the Administration had negotiated and brought to you and try to offer some thoughts as to where those contracts seemed beneficial and where there might be questions.

I would speak first on the positive side with reference to the contracts themselves. I find four areas where I think an excellent bargain has been struck, in several instances much better than I would have expected in trying to plat out what course this all might have taken when we first started discussing it a year ago.

I think one of the principal strengths of the contract lies in the provisions that the State will not suffer monetary loss by reason of an in-kind taking, compared to what expenses the State would be out, which would be none, if it just took in value. When the State takes in-kind there has to be a point in the production cycle when title to the gas passes. It cannot be, in my judgment, at a point after all of the processing has occurred and all liquids have been stripped out, and the State just walk in and say, "All right, we want one-eighth of the residue gas and we want one-eighth of the liquids free of any costs."

I don't believe that's the way it's going to work under your leases and under the practicalities of the arrangement. But since the gathering lines haven't been

built and the processing plants have not been designed or constructed, no one knows what those costs will be, and I think it very important that the contract negotiators realized that there was a risk, a substantial financial exposure on the part of the State, and that they undertook to protect the State against those costs. This, in my judgment, they have done in Article II, Sections 2.2 and 2.3 wherein, in effect, the buyers say whatever it is that the State is out in terms of out-of-pocket costs by reason of this in-kind taking, that the State would not have been out if it were value taking, then we, the buyers, agree to reimburse the State in full.

I think that was a significant concession on the part of the buyers to the State, and I think it's an important element of protection in the contracts.

Secondly, I think it is very much in favor of the contracts that the arrangements have been structured so that the State is selling one hundred percent of its present deliverability, but not one hundred percent of its Prudhoe Bay reserves. You will notice as you go through the contracts that of the three buyers, one is to receive twenty-five percent of the gas that flows that belongs to the State, another twenty-five percent, and then the third fifty percent.

Well, obviously, that's the full one hundred

percent of the deliverability as it is produced. But because the volumetric limitations are written into the contract in Article III, what we have is a situation that the State is not selling what it really believes that it has in totality. In this instance I operate on the strength of what I was told last year when I was up here, that the State's royalty share of recoverable reserve was anticipated to be in the order of 3.2 trillion cubic feet, and these contracts obviously sell less than that. So it's less than a complete sale of all of the royalty gas that the State expects to recover from Prudhoe Bay.

Personal judgment, I think that is prudent because it gives you an opportunity to have some operating experience behind you, it lets you see what the market conditions are like at that point in time when the total volumes have been delivered under these contracts, and permits you the flexibility and freedom to make new contractual arrangements if that appears to be in the best interests of the State.

Third, I think the arrangements for withdrawal of gas for in-State needs are very favorable. I think the protection there is quite good. I will express to you the view that these provisions may almost be too good when it comes time to try to finance construction

of a pipeline. It's going to be a little bit hard for a financial institution to look at a situation where the State has a right to pull back out one hundred percent of one-eighth of the gas stream, so that that throughput is not available to stand behind the generation of revenues for the line.

From a contractual standpoint, I see no reason in the world not to insist upon this bargain as far as the State is concerned. What I'm suggesting to you is that there may come a moment of truth further down the line when the financial institutions come to the State and say, "If you insist on this we can't finance it." To me, I'm trying to underscore what I believe to be the strength of the withdrawal provisions because I think they are very favorable to the State.

I am impressed with the provisions in the contracts relating to the retention of the State's rights in natural gas liquids. You've heard a number of people say, and certainly I agree with them completely, that the liquid content of this gas may be of greater value to the State than residue gas itself. I do think that the State has retained fully the right to remove the liquids, process them and do with them as they will.

You're not forced to do that. It's an option under Article IX. If you leave any part of the liquids

in the stream the buyer has to take them; you, the State, will be compensated on the basis of the increase in btu content of the gas that comes about by reason of leaving the liquids in the stream. So you, in effect, have an option as to whether to pull the liquids out or to leave them in. If you pull them out, they are yours to sell on the open market or to devote to uses within the State. If you leave them in you will be paid for the btu content. I think those provisions are quite protective of the State's interests.

Finally, I read with interest the different places in the contracts where the State has the right to withdraw or terminate because, since we are dealing in such such a flexible fluid situation, I would think it important to the State to know that they were not forever bound to these contracts, that if certain things happen that you might walk away from them without incurring any obligation or liability.

There are, I believe, four instances where the State can withdraw from the contract without penalty. It may do so if it is prevented by a Federal action from taking its royalty gas in-kind. The contracts may be terminated if a decline in production results in non-profitability to the State. The sales agreements may be terminated by the State if the State so elects after

the FPC makes a routing decision that is adverse to an all Alaskan line, and finally, the State may terminate if by January 1, 1979, all approvals necessary, authorizations, that the State feels necessary to get the benefits under this contract, if all of those approvals have not been received.

I think the latter quite a good provision. I think it lets you look at the decisional process at the Federal level. If it's something that the State could live with, you may do so; if you don't like the way it's structured, you've got the right to terminate the agreements. I think those provisions are all quite sound, quite protective of the State, and I think they are major sources of strength in the contracts.

The principal areas of difficulty that I have with the contract all relate to Article VI, dealing with pricing. There are several problems here. I've tried to be as exhaustive as I could in thinking up the problem areas that you need to be aware of. In the course of talking about them though, I'd like to give you an assessment as to whether I think they're problems of great magnitude or problems of lesser magnitude -- because any lawyer can find anything in a contract, you know, and say, "This might not work out too well." So I'll do the best that I can to give you an assessment of how bad

it is as we touch upon each one of them.

The first one relates almost directly, Representative Gruening, to the line of questions you were asking about the possibilities of a deregulation bill or any action that would result in a vintaging situation that would be hurtful to the State. The structure of Article VI is such that there is a proviso in Section 6.1 which has overriding effect on the pricing structure. I'm sure that each of you have read these contracts carefully, and you will recall that Section 6.2 provides a pricing mechanism if regulation continues.

6.3 provides a pricing mechanism if there is no Federal regulation, and 6.4 provides a pricing mechanism if Federal regulation starts, deliveries commence, and then Federal regulation terminates. So there are three alternatives, really, in terms of pricing, and then you pick up Section 6.5, which is important and which gives redetermination rights.

But Section 6.1, the last clause makes it clear that there is one condition that cuts across all of the pricing alternatives, and it is that so long as the pipeline buyers are subject to the jurisdiction of the Federal Power Commission, so long as their rates are subject to the jurisdiction of the Federal Power Commission, then the price that they will pay to the State

shall be no higher than the price which they are permitted to recover in their jurisdictional rates at the FPC.

I'm not surprised to find that the pipelines wanted that, because certainly you can understand that they don't want to pay you more than they can get back from their customers and, indeed, I would be surprised if all pipeline purchasers didn't bargain most strenously for this type of provision. But I do want you to be aware that the effect of it is to say that so long as deregulation does not occur the Federal Power Commission is going to be setting the price for your gas.

So far the State has taken the position that it is not a person within the meaning of the Natural Gas Act, that it is not subject to direct rate regulation by the FPC. I concur in those positions, but the effect of Article 6.1 is to consent to indirect rate regulation by the FPC because you are saying that the pipelines do not have to pay to you more than the FPC will permit them to flow through in their jurisdictional rate structure.

That problem disappears if appropriate deregulation legislation is passed. But if it does not pass, if we are with substantially the same form of pricing that we now have for some period into the future, then it seems to me that the 6.1 proviso does override the other pricing

alternatives that appear in the contract. Because of that, Representative Gruening, you can postulate a situation where a deregulation bill passes that deregulates the producer but does not deregulate vintage of gas that the State would be selling under this contract. That would occur if a deregulation bill were drawn so as to deregulate gas sold under a contract dated after a certain date.

I offer you the value judgment that that is a most unlikely occurrence. The Commission moved away from contract date vintaging in 1969 in the Southern Louisiana Two decision and has never returned to it. I believe that I have read every piece of gas legislation that's been offered in either House for the last four years, and I can recall no bill offered in either House that went to deregulation on the basis of contract alone. They are mostly cast in terms of new gas being defined as gas sold under a contract or delivered after a certain date, and it's an "or" delivery test. I don't really think it's likely at all that a deregulation bill would be cast so that it would be harmful to you.

As a practical matter, so that you will understand why the Congressional reasoning and the FPC reasoning seems to be moving in this direction, away from contract vintaging, it is simply because if you

permit a deregulated price to a producer on the basis of when he contracts to bring the gas to market, if that producer has been guilty of withholding his gas from market in anticipation of deregulation, then you have rewarded his wrongful conduct.

So, to me, it's not likely that people are going to go back to contract date vintaging as a test for deregulation. So my answer to the line of questions you posed is that there is, yes, a theoretic possibility that the State could be hurt by contract date vintaging in deregulation, but I do not believe that that possibility is substantial.

I do think that the present language of Section 6.1 is unclear in one respect. In my opinion letter, on pages six and seven, I attempted to spell out why I thought there was an ambiguity. I think, from my discussions with Mr. Byrd, that the parties did not intend the ambiguity to exist and it would be probable that the buyers would enter into whatever type of letter modification or letter of explanation that is necessary to straighten this out.

It seems to me that it must be made clear that Section 6.1's limitation goes out the window, becomes totally inoperative, if an appropriate deregulation bill is passed. I just don't think that the language

is altogether as clear as it could be on that point, but I don't think it's a major burden or a major obstacle to the contracts if the purchasers will agree as to what the proper construction of that provision is.

Other witnesses have advised you, and certainly I agree, that you cannot determine a sales price under these contracts as drawn. Section 6.2 will not give you a sales price because the FPC has set no price for Alaska.

Section 6.3 and 6.4 will not give you a price because they're conditioned precedent, deregulation, has not occurred. And so you have before you a contract that is indefinite as to price, and you have a contract where your price will ultimately be determined by someone other than the State. In the event of continued regulation your sales price will be determined by the FPC. In the event of deregulation your sales price will be determined by the prices which producers, working interest owners, obtain in their contracts.

So, I would want you to understand that you are giving up direct State control over the sales price through the pricing mechanism embodied in Article VI.

There have been a number of comments about whether we will or will not have deregulation, and if we have continued regulation, what is likely -- I'm mentioning at this point, because it's structured into my opinion

and I think it is a major concern.

So many things have happened so fast in the Lower 48 States in the natural gas business over the course of the past three or four weeks that I don't think anybody can give you an informed guess as to the likelihood of deregulation or not. We've seen two and a half million people out of work on a given day in the Lower 48 States because there wasn't enough natural gas to go around. We've seen the Congress in three days' time pass an emergency allocation bill that for the first time gives the President of the United States the right to reach into one interstate pipeline supply sources and move the gas to another interstate pipeline.

We've seen as of, I think it was Wednesday night, the President authorized Two Dollars and Twenty-Five Cents as an emergency purchase price that any interstate pipeline could pay for one hundred and eighty day emergency purchases of gas anywhere in the Lower 48 States.

All of this says to me that it is a time of great uncertainty. We will nationally, I suppose, sooner or later arrive at a decision whether we're going to move toward greater regulation and allocation on a national scale, or whether we move to less regulation and honoring of private contracts. I wish I had an answer for you, because I think if you knew what the future held, it would

make your job a lot easier.

But I cannot, in honesty and in good conscience, tell you that I'm confident what the future will bring. If deregulation continues, or if a deregulation bill is passed that is not appropriate to Alaska, and by that I have reference to the possibility that a bill might be structured like FPC and go to commencement date of a well rather than date of first deliveries. So you might have some gas up there that continues to be regulated even though a deregulation bill passes. But if some or all of your gas remains regulated, I hate to say it but I must say it, brace yourselves -- my judgment would be that the Federal Power Commission will determine a rate for Alaska as a separate producing area, that they will not treat you on the same basis with the national rate, as they treat the rest of the country. They have specifically excluded Alaska from applicability of their last set or rate orders, they have specifically excluded Alaska data from the calculation of a national rate, and to me that indicates that when the time comes for the setting of an Alaskan rate, it will be a rate peculiar to Alaska.

I am concerned, and I would want you to understand the reason for my concern, that an FPC separate for the State of Alaska will probably be not as high as Judge Litt

and they came up with a very low rate, relatively speaking, for associated gas. You can understand it. Gas was their responsibility, they could keep the price down and make everybody happy by putting the costs over on the oil side; so that's what they did.

The second factor that you've got going against you is that you do have a major, huge discovery up here, and obviously the more units of gas you have in terms of reserves added, the more units that you have to spread these costs over, then you come up with a lower per unit cost figure. So the arithmetic of FPC methodology is against you if they're going to set the rate for you. I can't really do much more than say that the structure and the methodology is just going to work against you; that's all there is to it.

But that is a condition beyond my control, or yours. It is only one of those things that you need to be aware of. That condition would exist whether or not you sign these contracts. The existence or the absence in the Federal regulation is not, obviously, going to turn on whether these contracts are signed or whether they are not. But in speaking with you today, I at least want to mention to you that it would appear to me that the State of Alaska needs to be very active at the FPC in any rate matters affecting Alaskan gas, because if you

mentioned in his opinion, of a Dollar, probably not be as high as some of the economic projections that have been laid before you over the course of this past week. And the problem essentially arises because of the structure of rate making methodology at the FPC. They try to set a rate for natural gas on the basis of what they perceive the cost of production to be, the cost of finding and production, and a reasonable rate of return to the producer.

They have, since 1968, been costing gas well gas where they could find a data series and they could determine how many feet were drilled in gas well exploration, what gas reserves were found, what the costs of gas production were. So their national rate determinations since 1968 have essentially been for new gas well gas.

You go back to the early Commission efforts at rate regulation when they tried to price associated gas, and they became enormously tangled up with the problem of cost allocation. Here are two joint products, oil and gas, they come out of the same hole in the ground, you spent a certain number of dollars to find it and produce it, so how do you allocate the cost between the two products. The FPC, since they had jurisdiction over gas, allocated a very heavy burden of costs to the oil,

leave it to them to do it for you without some evidence, and some input and some argument from you, you are probably not going to like the results.

I did have a problem with the redetermination provisions under Section 6.5. They were the same concerns that Mr. Swanson raised with Chairman Rader the second day of the hearing; and with the purchasers' representations about their meaning of Section 6.5, I no longer find an objection in that area.

Over all, to get back to the general structure of the thing, since your rate is going to be determined by somebody else, one consequence of entry into these contracts will be the necessity that the State participate in some FPC proceedings. Your rate, under this structure, in the event of continued regulation will be set either in a national or an Alaskan rate proceeding where the FPC determines by rule-making a rate applicable to the whole state, or it will come up in an independent individual producer's certificate case where one of the North Slope producers goes finally into the FPC with a contract and says, "Here is the price I bargained for. Let me charge it." And the FPC can approach the rate issue in that context.

Or, finally, if neither of those two things occur and deliveries commence, the pipelines that buy

from the State will take to the FPC their rate structure and ask for approval of what they paid to the State. There are three possible procedural mechanisms where the pricing problem can be reached by the FPC. Whichever of those three comes to pass, it seems to me absolutely essential that the State be there to participate fully. I don't think you can rely on other people to carry this important issue for you in that fort.

On the whole, if you asked me whether the pricing problems that I've tried to outline for you are sufficient to condemn the contract, I'm going to give you one of those "either/or" answers, I think. I'm not sure that what we're talking about here is a pricing issue, in terms of what the Legislature is going to be asked to do. I think it's a routing issue.

Having already stated that these contracts are unique and that, therefore, there's not much I can compare them with, I offer you the value judgment that I don't think you'll get better terms than this from anybody at this time and under these circumstances. I think that on the whole they're as good a contracts as you are likely to get.

The real question, it seems to me, and here I need to, I guess, go back a little bit -- I did come up here this time thinking that the State had already made a

decision about which route it supported and that the sale of the gas was an appropriate means to try to help influence a favorable decision on the routing. I can well understand it, because a lot of things that have occurred in the last year that many members of the Legislature and many citizens in the State might want to think through again, whether those are both questions that you would still answer in the affirmative. But if you come to the same answers and you say, "We do think that the routing decision is important to the State, we do think that the State should do all that it can to influence a favorable routing decision," then I suspect that the pricing provisions here should not be a bar to your approval. But I can't -- and I'd make it perfectly clear to you, you've got a third applicant in the game since I was here a year ago. I carry no brief for El Paso or for Alcan, I carry no brief for the individual purchasers under these contracts. Pick Tenneco, Southern, anybody else -- I'm just trying to speak to the concepts of what are you doing with the State's resource and is this a good time to do it.

I think there is a risk in not doing anything. I cannot tell you, and I don't think anybody else can tell you, how much it will influence the routing decision if these contracts are approved. I think, as Mr. Ward

said the other day, that most people would recognize that it will have some impact. I don't think, and this kind of disturbed me, about the way things sounded a time or two. I don't think what we're talking about is the State trading its royalty gas for lobbying efforts by two companies.

It seems to me what I was talking about a year ago and, hopefully, what everybody is thinking about, is that the State is holding out to a number of states in the Lower 48, "We will share our gas with you if you will help us get the route that we need." I have a jaundiced and prejudiced view, I suppose, of lobbying as such, if a corporate vice president thinks he's going to influence a Legislator's vote. I don't think that happens very often. I don't think that's the way to get things done anyway.

But I don't perceive these contracts as a means where you buy a corporate lobbying support and expect you're going to get anything. If you look at it that way, I don't think you will get anything. But if these purchasers, in your judgment, are responsible companies that know their business and can reach to their customers, and go to their customers and say, "We have the promise here in writing of some gas from Alaska if we help Alaska on getting the right route," then it seems to me

you've got to have some influence on the routing decision.

I think Judge Litt has spoken the first word, but most assuredly, he has not spoken the last word on the routing problem. An Administrative Law Judge of the FPC, and particularly Judge Litt, is respected by the Commissioners. They will believe him to be an honest man who has worked diligently with the record over many months, and I would anticipate that they would think that he is infinitely more familiar with the record than any of them can hope to become. But they will not abdicate their responsibilities to Judge Litt. I say that institutionally and I say it knowing the individuals. I think they will try their best to reach a decision on what they perceive to be truly in the national interest.

Certainly I think the same will be true when it moves over to the White House for Executive Agency decision. So I don't think the routing decision dies with Judge Litt's decision. I think it's still an open issue. I think it's possible that some persuasiveness can still be brought to bear on the issue.

Really, I don't ask myself so much, "Is it too early to enter into these contracts," as do I ask myself, "Is it too late that we entered into these contracts?" Once again, I'm not talking about individual buyers (I hope you all understand that), I'm talking about

the concept of the use of the State's royalty gas as a means of trying to influence what you believe to be in the State's best interest, and whether you come down on the side of Alcan or El Paso, that's beyond my concern and beyond my knowledge.

Whatever you do, it seems to me, perfectly legitimate that you use the State's resource in a manner that helps you get the best benefit for your State.

I preach a lot, I apologize. I guess I feel strongly about your situation up here because you're one of the few places that still has the opportunity of controlling your own destiny.

There are a couple other things that I guess are worth mentioning. I don't try to characterize them as good or bad since I think that your perception of them depends on things other than legal analysis. But I think the provisions of 11.4 are noteworthy, which grants to the Governor the right, in effect, to make a switch in the State's support. I really can't offer any judgment as to that provision. Certainly you have to be aware of it.

The contracts do contain certain options on State royalty gas that are triggered if the State effects a withdrawal of some of the gas covered by these contracts for in-State use. I think the option provisions, themselves,

are not remarkable and are understandable. I suspect that they reflect the necessary bargaining process of what State negotiators had to give up in order to get some of the stronger elements in the contract that I covered earlier. So I mention it only to make sure that I've tried to make you aware at least of the major provisions in the contract.

The contract is silent on one thing that I think is significant, and I'm probably beyond my depth here and, therefore, going to make a mistake or two. But my recollection of your severance tax structure is that if you take your gas in-kind, the one-eighth taken in-kind will probably not bear a severance tax. That is a substantial revenue loss that occurs by reason of an in-kind taking that would not occur if you took in value, and I don't think the contract deals with that. I don't think that the questions asked to the purchasers the other day, in effect were, "If you pay a severance tax component to a working interest owner will you match that and will you pay it to the State," and they said, "Yes," and that's fine.

In the event of the continuance of regulation they will be permitted to pay a severance tax component only as reimbursement for severance tax pay. So I don't think that the FPC will let them pay you the equivalent

of a severance tax component. So I do suggest, as I think one of the other folks did this morning, that it might be appropriate for the State to give some thought to its severance tax structure in conjunction with these sales arrangements.

One or two general thoughts, if I might, maybe it would save some time, before we get to individual questions.

I think several of you have indicated an interest in knowing whether or not these same or better terms could be obtained if the State waits until a later date to make a sale. I suspect that if the routing decision is adverse, if Arctic Gas is selected, I don't think you'll get these favorable terms because I don't think that your rights of withdrawal will be meaningful to you, and I'm not sure that a purchaser through that system would consent to it.

I'm not sure that you could get the same provisions on the reimbursement of costs incident to your in-kind taking. In essence, the four areas that I thought represented real bargaining pluses in the contracts, it seems to me if you're talking about a buyer through the Gas Arctic system, they have little reason to offer you those favorable terms. So it may be that waiting until a later date, in the event of an adverse routing decision,

you might not see terms as favorable as these again.

Some questions have been asked as to whether or not the State could obtain a higher price if they pursued some other type of sales arrangement. Again I have to offer you a value judgment because I haven't surveyed the market. There's not any real way that I could do that, but I can speak with reference to how sales arrangements are structured under FPC regulation. And I will say that any sale that you make to someone in the Lower 48, or in the State of Alaska, is going to involve FPC transportation jurisdiction and, in a sense, that sale is going to be subject to FPC review.

If you attempt to find a distribution company in the State of Alaska or outside the State of Alaska to sell to, yours will be a sale for resale in interstate commerce, and the transportation of the gas will be in interstate commerce. So I don't really think that you move beyond where you are now by looking for that type of purchaser. There are not many purchasers that are able to take the volumes of gas that you all are talking about delivering, so you've got, in one sense, a limited market.

Electric utilities, I'm sure, would love to have it to burn under boilers, but I am quite positive that the FPC would never grant transportation authority for

that type of use.

The FPC does have a procedure whereby high priority users can purchase gas from a producer. It's called Order 533(a). It is limited to two years. The buyer is supposed to receive only those volumes that offset his curtailment in high priority two and three usage, and I think it's just simply not applicable to the type of sale that the State would be looking to.

So, while I will not absolutely rule out any possibility of a sale at a higher price, I offer you the value judgment that you probably won't find one.

One of the Representatives the other day indicated that perhaps Section 13-B of the Alaska Natural Gas Transportation Act rendered the desirability of these contracts somewhat less than might have been true before the passage of that act. It seems to me that 13-B is helpful to the State only if the right route is selected. If the gas moves out of the State north of the Arctic Circle I don't know how you would ever implement your rights of withdrawal. You're just not going to have a means of getting it down to where your people are and where you hope your industry is. So it will look good on paper. It doesn't vanish if the Gas Arctic route is chosen, but it is hard to see how it is of much practical help to you.

I will confess to a certain academic interest over the last few days in the discussions that you all have heard with reference to the effect of transporation costs on wellhead prices. It's a very confusing area, and I will offer you my perception if you want it.

In a regulated market, transportation costs are not going to have a thing to do with wellhead price. The FPC is going to set a wellhead price based on what they perceive to be the costs of finding and production, and a reasonable rate of return to the producer, and they simply have no mechanism for looking at transportation costs as a function of that rate. I know of no instance that the FPC has ever set a producer rate based upon any consideration of transportation costs.

In the event of a non-regulated market, I think that what I have heard over the last several days with two sides of the argument, I've heard some truth on both sides, but I'm not sure that I've heard the complete truth from either side, and I mean no disrespect, obviously, by saying that. In a deregulated market transportation costs do have an influence, but they are not the only factor that influences wellhead prices.

The nature of the use to which the gas is going to be put determines whether it is appropriate to look at a number two fuel oil equivalency price. For some

uses a user will pay much more than a number two fuel oil price. So you have to look at the market to which the gas is going before you know what is your base point for comparison backwards, and in the absence of a fundamental change in regulation the average cost of purchased gas on a pipeline system is buying from you has an influence on the wellhead price in the sense that, indeed, regulatory agencies now tell a pipeline or distributor, seller, to roll in or average his costs. And if you're dealing with a buyer that has a low average cost to purchase gas, then what he pays you is influenced by the fact that he's working against a lower averaging base.

I guess what I'm saying is that in the event of deregulation, if you tried to determine wellhead price only by looking at transportation costs and only by equivalencies with number two fuel oil, I suggest that's less than all of the factors that will enter into it. I suspect that as of right now, trying to determine what wellhead price will be in the event of deregulation is largely a metaphysical exercise. I'm just not sure that it's productive. You'll get as may guesses as you get economists up here.

Now, we lawyers are more definite, you see. I'm sorry I've taken more of your time than I intended to. I guess, Mr. Chairmen, it would be appropriate

to offer myself sacrificially.

SENATOR RADER: Representative Rudd.

REP. RUDD: Mr. Moody, this morning Mr. Swanson mentioned the possibility of storing our gas in place for some time, until we have a need for it. Is that a possibility if we don't approve these contracts? Is that a possibility?

MR. MOODY: Well, I guess there are two sides to the question. Is it possible mechanically, physically?

REP. RUDD: I was going to ask both questions.

MR. MOODY: And is it possible ---

REP. RUDD: By law.

MR. MOODY: Regulatory. I better not make a guess on the first one because I really don't know enough about your reservoir and its mechanics, that I really couldn't give you anything of value other than to guess on it. On the other side of it, once again you've got to make a judgment as to whether we're going to be deregulated or continue to be regulated. Since my personal feeling is that we probably are going to face regulation, I think I'll deal with that one first.

If the producers start selling the gas stream into interstate commerce you would have to be most careful that some type of balancing arrangment or under-lifting arrangement with the producers had been reduced to writing and had been approved by the FPC, because in my judgment,

if eight-eighths of the gas stream starts flowing in interstate commerce without some advance approval for the State to be storing its gas having been had and obtained from the FPC, you would be met with the argument when you later wanted to change the flows that you were trying to work an abandonment and that Section 7-B of the Natural Gas Act would interfere with what you wanted to do.

I think it's something that perhaps could work but I think you need specific agreements and, to be on the safe side, I think you'd want to go for regulatory proof.

REP. RUDD: Could you give us your appraisal as to how likely it is the FPC would agree to such an arrangement?

MR. MOODY: I'd guess they wouldn't. I think they want your gas.

REP. RUDD: Would this hold true under both conditions of the Alaska exemption, whether it's in effect or not in effect? Would that have any bearing, do you think, on their decision?

MR. MOODY: I read Section 13-B to apply to withdrawal from the system after deliveries have once commenced. Maybe that's too narrow a reading. Assuming 13-B stays in the Act and your arrangements for storage were structured as part of a royalty sales contract, I guess you could

bring it within 13-B.

REP. RUDD: Thank you. I have one more question on another subject.

SENATOR RADER: Go right ahead.

REP. RUDD: I think it was Mr. Thompson who mentioned yesterday or the day before, that he felt that a lobbying effort in Washington would not really be a very important thing to do at this time because it is now a decision that is before the FPC and then the President, and Congress only gets into it after those two have made their decisions, and only has a very short time to evaluate the President's decision and, therefore, probably will not go against the President's decision. But you're a former Commissioner on the FPC, and you just mentioned that you thought that lobbying efforts would be valuable. Are you talking about influencing the decision of the FPC and the President and the Congress, or at what point do you think the lobbying would be most effective?

MR. MOODY: I'm going to, if I may, take exception to the word "lobbying".

REP. RUDD: I'm sorry.

MR. MOODY: No, really. Because to me it has a specific connotation; perhaps it doesn't to others. What I suggest will happen is that the Federal Power Commission

has been told to gather all the information they can in order to make the most advised recommendation to the President as they can, and the President and the Executive Branch has been told to gather all the information that they can, talk to as many people as they can.

I think those people are genuinely interested in arriving at the best decision they can. I would not want to believe, and I do not believe, that their minds are made up. I don't think that there is anything wrong with offering the views of concerned people, both at the FPC and to the people in the Executive Branch that are charged with this responsibility. I think that the opportunity still exists for people other than the State of Alaska and people other than El Paso, who have made their record, to go in and say, "We do have an interest and here's what it is, and we'd like for you to take us into consideration," and I think the opportunity exists both at the FPC and in the White House.

REP. RUDD: Thank you.

SENATOR RADER: Any further questions? Representative Hayes.

REP. HAYES: Thank you. Mr. Moody, you mentioned that one of four pluses that these contracts have -- interested me. One in particular that's of interest to many of us here is the right to withdraw our royalty gas for in-State use after it's originally injected into the pipeline

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system. Then you mentioned that when we get around to the financing that Alaska may have to face a moment of truth. Does that mean that we may have to subordinate that particular clause in order to make it possible for the pipeline companies to build this line and, if so, what do you think the chances are that we'll have to do that?

MR. MOODY: Well, I hate to borrow trouble, but I can see that a financial institution wouldn't be too wild about lending on an eight-eighths pipeline knowing that one-eighth of the through-put can be withdrawn at any time, because it's the through-put that generates the revenues that pay back the debt.

I guess I'd just be guessing if I said I know they're going to come to you and make you give it back. The best I can do is offer you the view that to me, representing the lender, you know, I'd say, "Gee, we'd better go get this straightened out some way, we'd better get some means of determining that the whole financing of the line is not going to be in jeopardy."

REP. HAYES: So we have three pluses and a possible plus.

MR. MOODY: From a contractual standpoint you've got a very good plus. My point is that it may be too strong a plus. You may have to give some of it back.

SENATOR RADER: That was my understanding of what you were

saying too, that we drove such a hard bargain that these people may not be able to finance the pipeline with what they have left.

MR. MOODY: To me it's quite conceivable it could deveop that way.

SENATOR RADER: Representative Gruening.

REP. GRUENING: Is the project so marginal in your view that what we do with our one-eighth will kill the project? I mean, can I fairly infer that from what you said?

MR. MOODY: No, I have no judgment about the economics of any of the three projects. I've never sat down to study them.

REP. GRUENING: But you're saying as it relates to private financing that our one-eighth is crucial.

MR. MOODY: I'm saying that from the standpoint of a lawyer who has done a little bit of work in representing lenders that any time you see something that threatens the revenue flow that you're looking to for repayment of your debt, you raise a red flag. But then I don't know, I have no judgment as to whether the difference between your one-eighth and eight-eighths is the difference in "go" or "no go" on the line. I'm sorry, I have never done any economic studies on it.

REP. GRUENING: But what you are saying though, it is the difference between "go" and "no go" as to whether a

private financer backs that line?

MR. MOODY: I think they're going to look at this provision very carefully, and a prudent lender is going to look at the reserves and he's going to look at the capacity of the line and the cost and everything else, and maybe this won't be a problem. But somehow I kind of suspect that some day somebody is going to knock on the door and say, "We need to discuss these withdrawal provisions with you."

REP. GRUENING: You mentioned that if the Arctic route is chosen we wouldn't get as favorable a contract. Let's say we don't enter into a contract and the El Paso route is chosen, do we stand to get as favorable a contract?

MR. MOODY: They struck their deal with you once. I guess they'd stick by the same deal, but I don't know them that well and I haven't asked them.

REP. GRUENING: You heard Mr. Tussing's testimony yesterday as to what he thought the international ramifications ---

MR. MOODY: I was enthralled with it.

REP. GRUENING: Yeah, I think the headline should have been "Members Entertained by Testimony," but I think what he says may have some merit. But I want you to comment on his view that the Canadians are going to make the choice and that if they do, in fact, make that choice, or cannot make that choice, isn't the El Paso route inevitable

if they can't make it, and what we do in this contract won't make any difference in that international decision making process?

MR. MOODY: I really had the feeling, listening to Arlon, that if I had his prescience about what our government was going to do, and what the Canadians were going to do, and Congress was going to do, and the FPC was going to co, I ought to be making a lot more money than I'm making. I suspect that an awful lot of what Arlon was saying were very well educated guesses as to what he believed would develop or might develop and, certainly I respect his judgment and the knowledge that he has and the facts from which he draws.

I don't come to the same conclusion about everything being cut and dried and that it's only the Canadians that have something left to say. It's not that I know that that's true, it's just that I am unwilling to recommend to you that you pass up the possibility that you've still got a way to do something. You see, I don't know, and all I've got to do is assume that the FPC and the White House will operate in good faith, that they still have open minds, that they're still willing to listen to reason, to rational arguments from responsible people, and if those assumptions are correct then there is still a way to try to make this routing

decision come out better than it has so far.

REP. GRUENING: I think what you say in terms of rational arguments having some effect is persuasive, I cannot believe anyone who says we can't have any effect on this decision. But the question before us is whether the commitment under this contract will have an effect on the rational part of the decision making. You described earlier that you thought it could have an effect in terms of, I think, the way that the public would perceive what we're doing here. In terms of the amount of gas and date of delivery that could occur under this contract what should we be telling, truthfully telling the American people they're getting under this contract so that they'll be persuaded that they should press their representatives for an all Alaska route?

MR. MOODY: That you're offering a share of your resource, and you're offering it under written contracts with responsible people that operate as buyers, sellers and transporters of gas, and that if the correct route is selected then you fully intend to abide by the terms of this contract.

REP. GRUENING: But can we say that in any other document or any other way and saying in effect that -- is there a more appropriate document than this to say, or a more appropriate spokesman to say this than the gas company?

MR. MOODY: I've forgotten which Justice it was on the English bench that once wrote, "As a man binds himself, so shall he be bound." It seems to me that the most appropriate way to express your sharing of your resource is in a contract. It's very easy for people to say, "Oh, we'll share with you, trust us." But, you know, you're to the point of the State committing itself in writing by solemn legislative and administrative acts that say, "Yes, we will share the resource." It seems to me that's appropriate.

REP. GRUENING: Do you think there is any danger, as long as you're making these political assessments -- could you tell us, is there any danger in assuming that the public is willing to go both ways; in other words, we'll allow you to take it back for any in-State use you want and we'll give you special legislative consideration for it, plus we're going to go along with your route decision? I mean, maybe we're asking for too much; I don't know.

MR. MOODY: It's a valid concern.

REP. GRUENING: One other question. You mentioned the provisions that you've analyzed although, in other words, if you were writing the contract out of the context of trying to affect some political decision you might try to renegotiate it to cover some of these.

MR. MOODY: Representative, I have tried to express in one of the opening paragraphs of this letter. It is very difficult to go in and pick up an executed contract and assess accurately whether it's the best deal that could have been struck or not. Those people who negotiate for you and against you have to go through a process of give and take, and unless you have been a party to the negotiation process and you know where you compromised and where they compromised, and where were the absolute points of no give at all, then you really don't know whether this is the best deal that could have been arranged.

I've read summaries of the contract negotiations. I don't know whether in any particular instance I or anyone else could have driven a better bargain for you, and I just wouldn't want to be in the position of saying that I don't think your negotiators did a good job.

REP. GRUENING: You mentioned that under these contract provisions a letter of agreement, especially 6.1 and I think 6.5 ---

MR. MOODY: Yes.

REP. GRUENING: -- could be corrected by getting a letter agreement or something on the record to clarify the possible ambiguity. As an attorney, wouldn't you recommend to actually get that into the contract?

MR. MOODY: It can be part of the contract by supplement so long as it's been done and properly agreed to by all parties before the Legislature is asked to vote on it. It seems to me that would be the determinative thing. They've laid a proposal before you but I don't see why it could not be supplemented with an additional paragraph or so before the Legislature votes.

REP. GRUENING: Thank you.

SENATOR RADER: Representative Parr.

REP. PARR: Thank you, Mr. Chairman. Mr. Moody, this contract is a twenty-year contract, and you've had a lot of experience with the FPC; what is sort of a rule of thumb, if there is any, on the length of contracts across the country in selling natural gas?

MR. MOODY: Yes, sir. Up until three years ago I would say twenty years was the industry standard contract. About three years ago the Commission went through kind of an evolution in its manner of determining to what gas certain rates would apply, and they permitted a higher price after the expiration of a contract if a new contract was entered into, called roll-over contracts.

You have a contract that expires, you would by FPC vintaging be held at a certain level, but the Commission kind of restructured and they said, "If you enter into a new contract we will permit you a higher rate."

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Leaving aside why that happened, whether it was good or whether it was bad, one practical consequence was that contract term shortened because people saw that by contracting for a shorter period of time they would have an opportunity to roll over the contracts and move to a higher price. As a consequence of that trend, the Commission, in Opinion 770-A, abandoned the roll-over contract concept and they refused to permit the higher rate for roll-over contracts. So we may now see a restoration of longer term contracts.

REP. PARR: In this last three-year period you're talking about, what would be sort of a guess as to the usual length?

MR. MOODY: There were still some twenty, some fifteen. The FPC does an every six month analysis on contract terms, and some were as low as two and three years. It would be hard really to say what the industry average was because it was such a short transition period and it really didn't shake out before it got changed again.

REP. PARR: I would like to, Mr. Chairman. You said also a while ago, Mr. Moody, in answer I believe to somebody's question, that we're not likely to get a better contract if we were to wait. Can I assume that you were talking about a regulated, as opposed to a non-regulated, situation in making that statement?

MR. MOODY: Yes.

REP. PARR: You said, when you first started talking, that nobody can really guess whether deregulation is going to come or not; and then just a couple minutes ago you said your own belief is that we will continue to have regulation. Am I quoting you right?

MR. MOODY: Yes, I'm afraid so. I'd like not to be quoted too widely.

REP. PARR: One last question, Mr. Chairman. You said that we might be able to offer some of our resource to some of these states through valid companies with good contractual arrangements, etc., and get their support. Can't we assume that the states which are going to profit by the other route, such as Arctic, are going to be throwing their support behind that route and you're going to wind up, perhaps, with simply a matter of counting the number of votes in Congress in favor of each one, and each one going for the one that seems in its own best interests, Illinois versus (shall we say) Alabama, and Texas versus New Jersey, and so forth?

MR. MOODY: Yes, sir. I would have thought that's the way it was going to develop. But you've got, it seems to me, something kind of unusual operating in your favor on this question. The producers are not entering into contracts because they're concerned about where they're going to be on the price structure. So as of right now

nobody is making a commitment of their gas that they can promise and that the Gas Arctic people can go state by state and say, "You're going to get so much, you're going to get so much." As long as the producers don't contract, you are the one party in a position to say, "We're going to share our resource with you on a specific basis."

REP. PARR: You don't think, Mr. Moody, that the companies such as Michigan/Wisconsin who talked to us the other day, or other big companies in the Midwest, are going to have their people believing they profit by Arctic Gas because there are no signed contracts? Is that what you're saying?

MR. MOODY: No. You know, human nature is a funny thing, and part of what's involved in this whole routing process are certain perceptions in the Lower 48 States. There is a perception that Arctic Gas will bring gas to the Midwest and to the Northeast at a lower cost; there is a perception that El Paso takes gas to the West Coast, that's already afloat in oil; there is a perception that Alcan started too late and hasn't studied their project properly and didn't make as strong a presentation as they could have under other circumstances.

You're dealing with perceptions when you are trying to get people to become involved enough to go to

the FPC or to the White HOuse and say, "Gee, this route would certainly help us." It seems to me that the commitment of specific volumes, even with your oil rights, so specific companies that reach specific states might be of some help in altering those perceptions.

REP. PARR: Thank you, sir.

SENATOR RADER: Senator Sumner.

SENATOR SUMNER: Inasmuch as I get the impression that price is probably going to be determined outside of what the State of Alaska is going to be able to do, doesn't it really come down to a very simplified option that in the end what we are able to provide for Alaskans, or the citizens of Alaska, will depend on whether we have an option of sending part of our royalty gas to an in-State petrochemical type of operation or whether it goes out of the State? Is it that simple?

MR. MOODY: Senator, I offer the judgment that from the very beginning price was of less importance to the State than was retention of the control of the resource.

SENATOR SUMNER: In your view is the Alcan project in a first, second or third running position?

MR. MOODY: I really never have gone into any of them, and I don't mean to dodge you, but the first of these applications were filed when I was on the Commission and some of the evidence came in while I was on the Commission,

and I really have hesitated and don't want to be put in the posture of endorsing one versus the other.

SENATOR SUMNER: And you're here to try as best you can to equip us with the knowledge that you have so that we can punch a button to decide whether we ratify a contract or whether we don't. If you had to punch a button and it comes down to no discussion or no nothing, one day a button has got to be punched; if you had to punch that button, would it be yes or no?

MR. MOODY: Was it Mr. Levy that said, "Elect me to the Legislature and I'll tell you"?

SENATOR SUMNER: But before we let you escape from us today we're going to keep you pretty close to that position. What is your recommendation to the Legislature?

MR. MOODY: I think you've got to go back to where you stand on the routing problem.

SENATOR SUMNER: That goes back to where the option is, and we're now down to the point where our destiny is pretty much controlled as to whether we have the option of using our gas in-State or sending it out.

MR. MOODY: Senator, obviously I have an opinion.

SENATOR SUMNER: Yes, sir, and that's what I'm trying to get.

MR. MOODY: My problem is, I feel very presumptuous, as somebody who grew up in Texas and has been in Washington the past five years, being in the position of saying to

men and women like you, who are elected to and who do represent your constituents, and who know your State, what their needs are and what their concerns are -- you know, how can I tell you what to do?

SENATOR SUMNER: No, that isn't what I'm asking you. I'm not asking you to tell me what to do, I'm asking you to tell me, on the basis of what you know, which you've got lots of years of experience, you're an expert, acknowledged, self-professed, being out of town with a briefcase, and I'm trying to determine in your mind which way would you go if it was your decision, if you were one of those people making a decision.

MR. MOODY: Maybe I ought to put it this way.

SENATOR SUMNER: Sometimes I wish the little button had a message like that.

MR. MOODY: If I lived in Alaska I would probably write my Representative and Senator and express the view that the routing decision was of terrible importance to the State, that this offered a means of perhaps arriving at a happy answer to the routing decision and that, therefore, my Representative would vote for it.

SENATOR SUMNER: Thank you very much. That's all I have, Mr. Chairman.

SENATOR RADER: Mr. Chatterton.

REP. CHATTERTON: Thank you, Mr. Chairman. Mr. Moody, I'm

looking for a value judgment on your part somewhat akin to the question you just had. Let's say that Chat Chatterton takes the position that he just doesn't want any straw, any conduit at all from Prudhoe Bay to Washington, D.C. where they can turn a switch, he wants to delay it as long as he possibly can; do you think that the approval of these gas sales contracts will change, will accelerate it? If I want to delay it, will I be accelerating the issue?

MR. MOODY: Having said that I think that the contracts would be of some benefit in the routing decision, I think it necessarily follows that if you have no contracts, it kind of just may help Gas Arctic, I don't know. I just don't know, and I don't mean to be flip or presumptuous.

REP. CHATTERTON: I'm not worrying about any route, I don't want any route.

MR. MOODY: I can recognize what you're saying and I would have said, "Now, Chat, don't worry about that," a few days ago, but I saw the Congress of the United States pass an allocation bill and, as you know, it was conventional wisdom that the pipeline industry producing states would just never let it happen. But emergency situations came up, the pressure was there, and the bill went through both Houses, and was signed by the President in

three days' time. I recognize your concern.

REP. CHATTERTON: Thank you.

SENATOR RADER: Representative Hayes.

REP. HAYES: Since we've discussed and mentioned several times that the most important aspect of this whole thing is the future in-State use of Alaska's royalty gas, do you think that by signing these contracts that we are in any way jeopardizing that opportunity in the future, as opposed to not signing any contracts?

MR. MOODY: No, sir, because I think the withdrawal rights are clear.

REP. HAYES: But we get into the situation of -- well, first of all, we've got the financing problem that we talked about. So, you know, we're going to be back to the drawing board, possibly.

MR. MOODY: Maybe I shouldn't have mentioned that.

REP. HAYES: The second problem is that once you get it into the system, once it starts flowing out for sale, they may decide that it's in the best interests to the country -- once it starts flowing out it's awfully hard to turn it back around again. That's another possibility of losing it. So it would appear that signing the contracts would put us in a more hazardous situation, could be more jeopardy on the possibility in the future of having our royalty gas available for in-State

use than if we didn't sign anything, we just waited a while.

MR. MOODY: It seems to me that turns on the perception of the same answer that Representative Chatterton asked. If you believe that not signing delays the construction of any pipeline system or transportation system, then what you suggest would follow. But if failure to sign or signing does not slow up the selection on the building of a transportation system, then you are vulnerable to the taking, whether or not you sign the contract.

SENATOR RADER: Any further questions? Senator Huber.

SENATOR HUBER: Most of my questions have been asked, or almost asked, Mr. Moody. One hasn't as yet. The change that you recommend in our severance tax structure, should we rush and make this effective before we get into a contract, from a legal viewpoint?

MR. MOODY: Senator, I'm not an expert on your structure, but I don't think so. I think my answer is that you have time to do it but it ought to be done before gas starts to flow. I don't think you want to tie it to the flow of gas. Somehow that seems like it's to late to do it.

SENATOR HUBER: The time structure then is that we should do it before the flow of gas, but it's not necessary to do it before we enter into the contracts, if we're going to do it?

MR. MOODY: If you will take the word of a Texas lawyer on Alaskan tax matters.

SENATOR HUBER: Would you care to speculate just a little bit further on Charlie Parr's question to you? It got very closely to what I wanted to get into, and the part that it didn't cover is, maybe in what magnitude of lobbying do you think it might take to change the perception of the people in the East that the Canada route is going to bring it to them; the perception in the Northwest that the Alcan route dumps it into them; and the perception in the Southwest, Arizona, California and so forth, that El Paso brings it to them with the first crack? Would you care to speculate briefly on what you think what might be the -- what kind of effort, how big an effort might be needed to overcome those ideas?

MR. MOODY: Senator, I wish I could be some help to you. You know, I think you're talking about a question of political science, or polling, or something I know I don't know, and forgive me, I just can't be of any help to you on that.

SENATOR HUBER: In that question, would you go along with me one more? Would you have any feeling in the area where you are living right now, Washington, D.C., if you and your neighbors feel that, for instance, the

Trans-Arctic Canada route might not give them the best bite on the gas or not? Do you know of any perception like that?

MR. MOODY: No. I think it's still probably as an issue that is being discussed not at the individual consumer level so much as at the State Commission, State Government, certainly involved industry level, but I doubt that Alaskan routing has become a matter about which individual consumers have views at this time.

SENATOR HUBER: I was getting into the end, of course, from necessary lobbying to convince Congress, based upon your earlier remarks. You haven't then noticed this, yourself?

MR. MOODY: No, I haven't, and, you know, you get involved in a certain area yourself and you begin to lose objectivity, because that's all you think about or all you talk about, and I'd be a very poor person to ask what people in Washington, D.C. feel about this, because I would necessarily reflect my own thoughts.

SENATOR RADER: Any further questions of Mr. Moody?

Mr. Moody, we thank you very much, and I know that Mr. Kilgore and Mr. Swanson both have reservations out, so I think that we'll excuse you gentlemen from further attendance this afternoon, although we still do have some members of the public to be heard.

You're welcome to stay if you wish, but as far as the committee is concerned I think it would be well to excuse you to try to make your plane connections.

MR. MOODY: Thank you.

SENATOR RADER: Let me find out before we take our ten-minute break where we stand. I have a list of witnesses that are possibly here or possibly not. Is Mr. Heinmiller here to testify? I see Mr. Penney and Paula Easley. Do you wish to testify?

MR. PENNEY: Yes.

SENATOR RADER: Carolyn Berg, is she here? Dennis Schlofeldt, from the Fairbanks Chamber of Commerce. I'll assume that he's not going to testify. Is there someone here from the Associated General Contractors who is going to testify? There's no one from the Associated General Contractors.

Under those circumstances, we have Mr. Penney and Ms. Easley from OMAR here to testify, the only remaining witnesses. Does the committee wish to take a ten-minute recess, or shall we take their testimony?

SENATOR HUBER: Let's take five minutes.

SENATOR RADER: Let's take a five-minute break.

(Whereupon the hearing recessed at 5:25 p.m. and reconvened at 5:35 p.m.)

SENATOR RADER: Would the committee come to order here?

We have Mr. Robert Penney and Ms. Paula Easley. Would you identify yourselves and who you represent? I suppose you would like to make a statement and then open yourselves to questions. Would that be the way to proceed, Mr. Penney?

MR. PENNEY: Yes, that would be fine, Mr. Chairman. Chairpeople, if that is the correct term, my name is Bob Penney, and I'm President of the Organization for the Management of Alaska's Resources. On my left is Ms. Paula Easley, she is our Executive Director.

This month OMAR is two years old. It was started some two years ago, with the idea of having some citizenry input into what happens to the development and/or the management of Alask'a resources. One of the first goals and projects that we took on was the issue of this natural gas line, and since then we've spent many, many hours and an awful lot of time trying to at least get a layman's understanding of what's really happening.

We have an office in Anchorage. The address is the Fourth Avenue Theater Building. We have a one-man office in Fairbanks, Alaska National Bank, and this next month we'll have an office in Seattle, and we have an associate office in Washington, D.C. under USA, Alaska. We have forty-nine directors from all over the State, and we have an executive board of eleven people, and the executive board meets once a week. We have public meetings once every Thursday in the Anchorage office.

I'd like to start off by saying OMAR doesn't really say who builds the gas line, we never have. We don't care where it goes, through what cities it may

pass; we just say it must go to a tidewater, ice-free port within the State of Alaska. And our second point, in our estimation, Prudhoe Bay gas is going to be produced. Now, it's produced with the oil and, as we understand it, we don't own one-eighth of the gas, we own one-eighth of the production and initially, unless we take it in like kind, we own one-eighth of the revenue. And, as we understand it, if we elect to take it in like kind, as Commissioner Martin has done, we then can take one-eighth of that production of that gas in like kind or take the gas itself.

(b) Per Atlantic Richfield Company engineers (Chat was at the meeting) it will cost nine to ten and a half percent of the gas to reinject it into the ground.

(c) It's against the law to flare it, as it should be.

(d) Eighty-seven and a half percent of the gas is already sold to others. It will leave the State, the rest of the country will demand it. There is a Federal law that sets a time frame for delivery of this gas. The gas is going to be produced.

Our share, as brought out by Mr. Moody, of the estimated three and a quarter trillion cubic feet, we have in this contract before you sold or are endeavoring to sell eighty percent of that gas, or 2.6 trillion feet,

and that amounts to eighty percent of the gas. Somebody said the other day they thought only seventy-five percent should be sold, and this is approximately eighty.

Our surplus royalty gas has to be sold for a period of time; that's what our observations have given us. We can't use it all right now in the State. I believe the State of Alaska looked for four and a half months trying to find a user for that gas specifically within our State. OMAR really feels this, and the reason we feel we're for this line is as follows.

We feel that the eventual use of the royalty gas within our State is the number one reason and benefit that Alaskans will accrue from this gas line.

(b) At a flow of three hundred million cubic feet a day, this royalty share equals, according to our figures, 2.2 times the amount of gas presently being used by forty percent of our population, the Anchorage Bull.

Last year the State could not find, nor is there a user at this time, who will agree to use or develop all the gas within our State.

(d) OMAR concluded over a year ago that we have to sell our surplus gas in order to have it back again some day. The eventual use in our State, as we stated before, the eventual use in our State of that gas should

be our number one priority.

Number Four: Prudhoe gas is going to market and the routing of that gas line will be a political decision finally decided by the Congress of the United States of America.

(a) We initially started working for a royalty gas contract at the recommendation of Senator Stevens and Representative Young over one year ago. They told us the route would probably be a political decision, just as the oil line one was.

(b) El Paso's application, in our opinion, is the overall number one choice for Alaska. Let's face it, they're a pretty small company in the big picture, when compared to the forces and money behind Arctic Gas at this time.

(c) We have been urging Commissioner Martin and the Administration since last February to conclude a royalty gas sale as recommended by the Congressional Delegration. As far as we're concerned, Guy Martin took a long time, worked on it very thoroughly, and went through extensive negotiations. We believe that last April 14 the contracts were almost signed and would have possibly been included for review by the last Legislature, but they were not completed until this November.

A sale, to be most effective for our State, should have been concluded, in our estimation, last spring. It has taken twelve months to get this contract before you in the steps it's in. Six to eight months from now it will all be over, the decision for the routing will have been made.

(d) The FPC Judge stated many times during the testimony and asked, "What's Alaska going to do with its gas? Is their gas going to go into the system? Are they going to keep it?" This contract you have before you was entered into the FPC record in its rough draft on the last afternoon of the last day before public testimony was closed.

(e) If all the gas goes to Arctic and if our State found no new reserves for some reason, wouldn't it be something if Alaska ended up some day like Louisiana, some years hence, with a shortage of gas? It's not probable, but it is conceivable.

(f) A political decision? Alaska is using all the forces we can to affect a Congressional decision. Do you mean like we did for the oil line? Or like we did for Statehood? You bet we are! If we don't stick up for our own state, I don't really think anybody else is going to.

Here are some of the letters we have received

from Senator Stevens, Senator Gravel and Representative Young dated November 2, November 5 and November 17, 1976, mandating a royalty gas contract.

MS. EASLEY: Last fall when we were getting pretty nervous about whether the royalty gas contracts would be concluded in time to be included in the FPC record, we asked Don Young and Ted Stevens and Mike Gravel to meet with us, and we did separately. And we asked them each a very important question. We said, "Do you still consider the royalty gas contract critical to the success of the Trans-Alaska gas line."

Ted Stevens told us that if we did not have the royalty gas contracts we didn't have a chance to win. Don Young said the same thing, and Mike Gravel said the same thing in different words. So we were convinced then, as we are now, that that is the most important thing that we need in order to do our job in committing the funds that have been contributed to our organization to carry this fight to the nation.

MR. PENNEY: November 2 in a letter to Honorable Jay Hammond from Mike Gravel: "In response to a request from the Organization of Management of Alaska Resources, I am putting on paper my position with respect to the commitment of Alaska's royalty gas. I have enunciated this position on numerous public occasions, both in Alaska and

Washington, D.C. Without doubt, the commitment of Alaska's share of the Prudhoe Bay natural gas could bring us allies in our cause if only because the beneficiaries would thereby have a proprietory interest in the success of our endeavor, designation of an all-Alaskan gas line."

November 5, in a letter from Senator Stevens, to Paula Easley at OMAR: "Dear Paula: I am writing to confirm to you my feelings that Alaska's royalty gas should be committed so as to pick up as much support as we possibly can gain in the Congress, in the South and in the Southwest. As you know, I have not expressed any opinion on the question of that share that any respective purchaser receives. However, these commitments will only make sense if they are associated with support for the all Alaskan line, and to get that the share to the new supporters must be credible." That's the time when we were being asked by, for instance, Senator Stevens wanted to see Tenneco, I think, at the time get it all, and Senator Gravel was thinking that El Paso should have gotten half. But it was a decision of what the percentages was, was left up to the State Administration. In fact, we didn't make any comments because we don't think that's within our vein.

"The recent report of the Berger Commission's

staff recommendations (continuing with the Senator's letter) reinforces my feeling that we have a real chance to win, and when the review of Alaska's gas transportation system comes before Congress we will need all the help we can get."

November 17 from Don Young to the Honorable Jay Hammond, in addition to a wire he had sent the prior day. "It is timely that the State has taken this action to achieve the goal of an all Alaskan route and to preserve the State's option for use of its royalty gas in the State. In the past, FPC Hearing Judge Nathan Litt has repeatedly inquired about the disposition of the State's royalty gas. It has been argued that if the State sold its gas it would be an unrefutable indication that the State is willing to do all that is in its power to commit itself to an all Alaskan route. Now at last this is the case and any reservations on this point can be swept aside."

Political decision? It is. If we don't listen to and seek the feelings of our Congressional Delegation as to what should be done on an issue decided in Congress, then who should you ask.

Number A: I would like to take a moment out at this time to do the same thing that Russ did, and I would like to publicly say how much I thought Bob Ward's

testimony was really right on the button yesterday, and he renewed my respect for him so much -- that he just told it like he really thought it was. I thought that was probably one of the nicest presentations I ever heard anybody give, particularly when they've got to have the least desired position of anybody involved. I thought it was well done.

We concur with that thinking. We thoroughly endorse the concept of these contracts. As we said, it's taken twelve months to get this far. We weren't privy to the negotiations. When last April we asked Commissioner Martin how negotiations were to be handled he told us no one was going to be involved but the four companies and the State. We understood and agreed. It took almost seven months to conclude these negotiations.

We really can't answer the questions as to the technical terms and things that you've heard now. The only thing that we can do is address ourselves to the concept of the contracts, which was initially told to us by the Congressional Delegation.

We have some concerns about the switching clause, and we've dicussed it at some length. We have a couple of suggestions after, if you want to. It's hard now for us to judge what's going to be hindsight in two to three years from now, and I'm sure it was

awfully hard for Commissioner Martin and the attorneys to judge now the best contract to draw for probably 1982. But I think from testimony I've heard here, I think the contract is probably as well done as it could have possibly been.

After all our encouraging Commissioner Martin to finally conclude a sale, we have to admit we think on an overall basis the contract really exceeds in many ways our best expectations. We think overall that he's done a fine job and actually has done the best he possibly could for our State, particularly under the circumstances.

One of the points that, as we understand it -- in essence if this contract is inked and it goes for approval, or if it doesn't go for approval but if Congress eventually approves the all Alaskan route as it's proposed, as we understand the contract, the next day our Governor could say, "We have the route now; however, we have an in-State use for the gas and two years from now we're going to take it back," and then two years hence, even before the line is even built, before it's ever constructed, we can cancel out the terms of the contract. I just have a feeling that there's got to be a little faith on both sides, because I don't know how I'd sign it if I were a gas company. But evidently they did think it was all right.

One other point that hasn't been brought out and I don't know why they don't want to talk about it, but I'm going to talk about it because I think it's very important. But El Paso, in essence, and I think you'll find that as we go into this the next six months and some more testimony, if you want it, will show that the financing of either one of these three routes is going to be one of the major critical things, and we think at this time it is the major critical stumbling block for Arctic Gas. And we have testimony, if you want to review that further.

But El Paso, in essence, has already got twenty-five percent of their system financed, as we understand it. Their tankers are going to cost 1.6 Billion Dollars, which is a quarter of their project, and under the Maritime Act (I don't remember the name of the Act) there is a low interest rate available for that, and also in a Federal insurance. So, in essence, they've already got twenty-five percent of their package cut and done. I don't know if that's been brought out before, I don't think it has.

In summation, don't forget, we won't have any accessible surplus of royalty gas if Arctic is certified, and I really think people lose sight of that. We will just have dollars of revenue from then on, because Mrs.

Jones is going to be cooking eggs in Ohio for the next twenty-five years with our royalty gas.

And (b), we think this is almost as important: if either Canadian line gains approval, you will then have an established corridor from the heartland of our State funneled directly to the South 48. If we ever want or choose then to see Pet 4 or other resources used or developed within our State, the chances of doing so will become much, much more remote. Whatever you do with this contract, somebody, some day is going to buy a portion of our surplus royalty gas, and we think that if El Paso, Southern and Tenneco would be foolish enough -- they would be foolish, they'd be unfair to their stockholders, and less effective for Alaska if they publicly review their game plan for approval of the Trans Alaska line. If they do, they're almost sure to read again about it in Jack Anderson's column or else somewhere else in national print. If you haven't heard about the column, I'll tell you about that.

They are large companies, they need the gas, and "no ticket, no laundry." If they don't work with us they very probably will get no gas. So we have to have some reliance on their ability to perform.

(e) To me, personally, this contract is also important nationally, as it's like the tapping of a pencil

on the negotiating table by the State of the Far North, that we're not asleep, we are interested in our own destiny, we do want a say in the use of our own natural resources, in our way of life, we do want to get off the Federal dole, and we do want to direct our own heritage.

We have over one hundred and fifty press clippings. Somebody asked if this was going to be news across the nation, and I'll let Paula enunciate on that. This news of the royalty gas sales has already been in most of the major papers in the United States.

MS. EASLEY: I'm sure most of you are aware of that, and unfortunately it has been reported and accepted as an already concluded situation, and quite a few of the articles have mentioned that the contracts do have to have the stamp of approval of the Alaska Legislature. But the way it is stated, it's just been that it is an assumed fact. And we are concerned about this element of it, should the contracts not be approved, the effect of that at the national level in indicating to the public and to the Congress that Alaska is not behind the proposal that it professes to be, and that eighty-five percent of its citizens say they are.

MR. PENNEY: Last, review, assess, discuss, make sure it's right for all of us, if you have to, this contract. The

final terms are in your hands. But, if you will, pass it out as soon as you can with a large majority. Affirm and then make it your first step in the fight for our own gas line.

Then second, (that's the first step) pass an appropriation bill to be used nationally in an effort to tell the Alaskan side of the story, that the all Alaskan U.S. route is the best one for all of the United States.

Then thirdly, we respectfully ask that you do everything you can legislatively to see that it's "easier" to go through Alaska with our gas than through the middle of another country.

SENATOR RADER: Thank you both. Any questions? Senator Huber.

SENATOR HUBER: One short one. Bob, you didn't agree with Bob Ward's testimony so much as to agree with his bottom line, did you, that it wouldn't make any difference?

MR. PENNEY: No, John, but if you'd like to -- some of the points he brought out we think were very valid, particularly as far as the part that gets into problems in Canada, and we researched those very thoroughly. We subscribe to two clipping services from Canada, and it keeps one person busy just reviewing those, and we think we have a pretty good grasp or feeling for what is taking

place in Canada, at least as far as the press reports. And if you want to get in and talk with some of that, we can tell you where we think some of the tough parts and some of the good parts will be.

SENATOR HUBER: You at least agree that he was very candid?

MR. PENNEY: Yes, sir.

SENATOR HUBER: As far as the last line -- I wanted to be sure you didn't agree with his last line.

MR. PENNEY: That's true, John, but I was very impressed with his testimony. One other aside, there has been some mention in talk made about the treaty here, and last February 1, I believe, Aron Tussing brought this up, so we will be able to see how his suggestion worked. But February 1 we sent a letter to Senator Gravel, Senator Stevens and Don Young, and in essence said this, that while we understand that the U. S. and Canada are agreeing to the treaty in which no line will be taxed any different than somebody else's line, as we all know the -- just let me read the paragraph. "We at OMAR are concerned that the provinces through which the Arctic Gas or Alcan Pipeline might pass have not ratified nor endorsed this treaty between U.S. and Canada. We are all aware the provinces of Canada have unusual taxing powers when compared to those enjoyed by each of the states of the United States. We ask that you consider

a proposal requiring each province through which a Prudhoe Bay gas line might pass to give a written pledge to support these treaty provisions before the U. S. Senate ratifies the treaty itself."

SENATOR RADER: Any further questions? Senator Sumner.

SENATOR SUMNER: You mentioned an appropriation. Did you have a figure in mind or have you gone through some other channels with that?

MR. PENNEY: Senator Sumner, Mr. Chairman, yes, we have. We've projected out two or three different things that could be done. But if the State were to hold down its expenses as closely as possible, we think it's going to require a Three Hundred Thousand Dollar contribution just on the part of the State itself to do any kind of effective job. But there are so many things we could be doing in the next six months to try and win this thing. There are so many avenues we could explore. We've asked the Governor, and Lowell Thomas is going to take another trip now for thirty days. We have to raise the funds to take care of his airplane tickets. He was very effective last time. He's written letters to every one of the other Attorney Generals throughout the United States -- or Lt. Governors, excuse me, asking them about the Alaska route. There's an awful lot we could be doing. We're going to have two more flights going back

to Washington, D.C., about a hundred and ten people, later on this spring and early summer, as soon as our Delegation tells us. And there is so much we could be doing, but if we don't start doing it, and if we don't start doing it right away, and really if we do nothing, and we get nothing, that's just about what we deserve.

SENATOR RADER: Any further questions?

MR. PENNEY: Thank you very much.

SENATOR RADER: Thank you very much. We have a number of exhibits that we need to introduce. Let me just identify them. We have a letter from United States Senator Mike Gravel supplementing his wire of several days ago. That will be Exhibit 20. I won't read it, it will be attached. Exhibit 21 is a series of correspondence including a letter from the Lt. Governor of the State of Alabama, a letter from George E. Smith, Alaska Chapter of Associated General Contractors, a letter from Robert L. Hardick, Anchorage Chamber of Commerce, a telegram from A. L. Swalling of Anchorage, Alaska, a telegram from J. A. Sproul, a telegram from Richard L. Maullin, a letter from Mrs. Jeanne Wilson, President of Greater Fairbanks Chamber of Commerce, a letter from George Easley, President of the Easley Construction Company, a telegram from James T. Jefferson, of Jefferson Enterprises, Detroit, Michigan. Most of these were responses to our

invitation to come and testify, and they sent written letters or telegrams expressing approval or disapproval of what we were doing. I don't intend to read them but I intend to make them a part of the record; so that will be Exhibit No. 21, called miscellaneous correspondence.

(Whereupon Exhibits 20 and 21 were duly marked.)

Do we have any other ---

SENATOR HUBER: Mr. President, may the list to whom invitations were sent to be a part of the record?

SENATOR RADER: Senator, I don't know that we can do that. Representative Gruening's office, I know, sent out some and my office sent out some in two different groups that had some overlap. I'd invite you to come to my office. We've got the letter from the Legislative Affairs people, and, Elke, maybe you know more about those lists than anyone. Would you explain to us what ---

MS. KALLAB: Yes, to the extent that I can. As far as on the Senate side, the list that we initially began with was furnished to us by the Department of Natural Resources which are used as lists as far as Oil, Gas and Royalty Board invitation lists. Those are the three lists we worked from.

As it turned out, in the confusion, everybody got an invitation. So I don't think we've lost anybody from the Department of Natural Resources that has been

on that side.

On the House side, as far as Representative Gruening is concerned, I know that he invited several people that were also invited by Senator Rader, namely Dr. Tussing, and in addition he invited Dr. Michael Scott to testify for the joint hearings here. I don't know, but I'm sure aide, Brian Rogers, will have a complete listing as to what other invitations were issued, either verbally or by writing.

The material that went out through Senator Rader's office is very readily available and could be very easily made a part of the record.

SENATOR RADER: Without objection, I will make available a list of the invitations sent out by my office, and it will be marked Exhibit No. 22. Representative Gruening, do you want to supply such a list for Exhibit 23?

REP. GRUENING: That's fine.

(Whereupon Exhibits 22 and 23 were duly marked.)

SENATOR HUBER: My only reason for the request was so that the record should show that we had invited a large cross section of people so it couldn't be said that we had a selected list later on.

SENATOR RADER: Fine.

REP. GRUENING: Mr. Chairman, in that regard you might want to put another exhibit, and that is newspaper ads that

were run by the joint committees, and we might even get a proof from the paper to attach so they know the dates.

SENATOR RADER: How many newspaper ads were run and in what newspapers?

REP. GRUENING: Daily News Miner, the Anchorage Times and the Daily News.

SENATOR RADER: One ad or several ads?

REP. GRUENING: Two days in each paper.

SENATOR RADER: If we can find a copy of that, that will be supplied to the reporter as Exhibit No. 24.

(Whereupon Exhibit 24 was duly marked.)

SENATOR RADER: Do we have any other requests for exhibits to be attached? We have one final exhibit, No. 25, which will be supplied by the Department of Natural Resources, and with that I take it that concludes our joint hearings; is that correct?

(Whereupon Exhibit 25 was duly marked.)

REP. GRUENING: Do we have the relevant statutes attached in there?

SENATOR RADER: No, we do not. Exhibit 26, would your office supply what you consider to be the relevant statutes?

REP. GRUENING: Sure.

SENATOR RADER: Exhibit 26 will be the relevant statutes, to be supplied by Representative Gruening's office to the reporter.

(Whereupon Exhbit 26 was duly marked.)

SENATOR RADER: Ms. Easley.

MS. EASLEY: I'm sorry, I just gave the reporter some telegrams and letters from other organizations that had asked us to speak on their behalf. Can she just do that, write them in?

SENATOR RADER: I'll make that Exhibit 27, it will be called miscellaneous correspondence and written testimony submitted by OMAR on behalf of others.

(Whereupon Exhibit 27 was duly marked.)

SENATOR RADER: Are there any other exhibits that should be made a part of this written record? Ladies and gentlemen---

REP. GRUENING: John?

SENATOR RADER: Yes.

REP. GRUENING: I know you want to get out, but what are your plans for talking to the Department of Resources people?

SENATOR RADER: Mr. Boness was scheduled to leave Sunday for Washington, D.C. and be gone for several weeks to work on the Federal Power Commission brief. Commissioner Martin has submitted to both you and I a schedule of his activities. It appeared to me that if we did not meet with him Monday -- Mr. Boness agreed to stay over and Mr. Martin agreed that Mr. Boness' presence was important if he was going to submit any rebuttal testimony -- it

appeared to me that if we did not meet Monday it might be several weeks before we could meet again.

It was my judgment and it was my feeling, as the chairman of our committee, and I've announced it in the Senate, that we will meet with Commissioner Martin and Mr. Boness of the Attorney General's office, and whomever of their staff that they deem important, to take any supplemental, rebuttal or additional testimony that they think has been brought out by any of the testimony that has been presented thus far.

REP. GRUENING: What time?

SENATOR RADER: 10:00 o'clock, here.

REP. GRUENING: We normally have a session. We'd like to attend.

SENATOR RADER: Our problem is our session. I scheduled it for 2:00 o'clock. As I recall, I talked to you and I thought that you were not interested in this, so I scheduled our session for 2:00 o'clock.

REP. GRUENING: It was my understanding it wouldn't be part of the record.

SENATOR RADER: It will not be a part of the record.

REP. GRUENING: But it is from your prior statement that they will be submitting something and you're taking testimony.

SENATOR RADER: They will submit written testimony or whatever

they think is important for this record, and I don't know what that's going to be. But our committee wanted to hear from them and didn't want to wait two weeks for it.

REP. GRUENING: Well, I'm wondering -- I haven't talked to the rest of the committee, but there might be some interest in talking to these folks if it's going to be on the record.

SENATOR RADER: I did not plan to have the reporter here; in fact, the reporter had asked to be relieved. I did not intend that it would be a part of the written record. If you are interested, let's make it 10:30, if we could do that.

REP. GRUENING: Whenever.

SENATOR RADER: All right. Now let me ask you this: if you wish, we can make that a part of the joint hearings and ask the reporter to come back. I don't know whether the reporter can or not.

REP. GRUENING: I don't know if that's necessary, but as long as Mr. Boness is going to be here especially for that, we might as well make it a half an hour later and we'll all attend.

SENATOR RADER: All right. Then I think we should continue the joint hearing, and I will ask the reporter then to come back at that time. I understand we have the

courtroom committed to us at that time, 10:30 Monday, and I'd like to ask the staff if they will make certain that is posted on the bulletin board; my own staff if they will contact the Department of Natural Resources and inform them, and try to get a page over here from the Senate, or send a page over here at a quarter to 10:00 to inform people who come here for that purpose that the hearings will not commence until 10:30, and to see that order is preserved in the courtroom.

We will adjourn until 10:30 then Monday.

(Whereupon the hearing adjourned at 6:05 p.m.)

JOINT PUBLIC HEARINGS

of the

ALASKA STATE LEGISLATURE

on

SCR 3, 4, 5 and HCR 11, 12, 13

"THE PROPOSED SALE OF ROYALTY GAS"

January 31, 1977 - February 7, 1977

Juneau, Alaska

VOLUME I - APPENDIX

CONSULTANT PRESENTATIONS

Michael J. Scott, Assistant Professor of Economics ..... p. A-1
ISER, University of Alaska (2/3/77)

AGO 546270

after a ten minute recess and we will be prompt on ten minutes.

(Whereupon the hearing was recessed at 2:50 p.m. and reconvened at 3:00 p.m.)

SENATOR RADER: The committee will come back to order. We have asked Dr. Tussing and his associate to appear out of order or they rather asked that they might appear out of order, Mr. Scott, because of commitments that they have tomorrow.

Dr. Tussing, we will follow whatever order of presentation you and Mr. Scott think would be most appropriate. Do you wish to make a presentation first and then questions? Would that be the way of proceeding?

DR. TUSSING: Well, I think the way to proceed would be to let Dr. Scott go first and then to ask questions of him and I might have some comments on his answers. Dr. Scott has done an analysis of the Task Force Report and the documentation by the Department of Revenue for the Task Force Report. It is a technical analysis.

I intend to range more broadly on national and international political aspects of the contract. I am willing to take responsibility for everything that Dr. Scott is going to say because I have read his analysis. He can't take responsibility for what I am going to say because I don't have a prepared statement and I was not

quite sure what topics I was going to handle before I got here. So don't blame him for anything nasty or unpopular that comes from this side of the table.

SENATOR RADER: I'd like to have both you and Dr. Scott, you are appearing here as expert witnesses and, therefore, a statement of your background and your qualifications would be appropriate in the record.

DR. SCOTT: My name is Dr. Michael J. Scott. I am an assistant professor of Economics at the Institute of Social and Economic Research, University of Alaska. I am a professional economist with a Ph.D. in Economics from the University of Washington. I am associated with the Institute's Man-in-the-Arctic-Program, which is an econometric modelling effort of Alaskan economy, and I have specialties in natural resources, public expenditure modelling and Alaskan cost of living.

I was requested by the committee to evaluate the report, "A Comparative Evaluation, Prudhoe Bay Natural Gas Pipeline Systems", prepared by the Gas Pipeline Task Force, November 1976, to check its technical accuracy as a supporting document to the sale of natural gas to El Paso, Tenneco, and Southern for the expressed purpose of securing an all-Alaska gas pipeline.

I was asked to do this since I had previously, in late November, evaluated for the Legislative Affairs

Special Subcommittee on Oil and Gas Taxation, a study by Dr. David Knudson of the Department of Revenue, which was titled "A Comparative Economic Study of Three Competing Alaskan Prudhoe Bay Natural Gas Transmission Systems", and possibly also since I was involved in the ISER studies on the subject of three gas transporation systems beginning in November 1975.

My comments, accordingly, will be directed to the internal logic of the section of the Gas Pipeline Task Force report entitled Economic Factors. I regret that I am unable to discuss the options for in-state use of gas. At the time ISER was doing its studies (that is April 1975 through June 1976), we were asked to look at only export options. We did this for the Department of Interior and the Federal Power Commission staff. Then, too, our analysis mainly took place before Alcan's proposal was before us, and there may have been delays in construction which we could not anticipate. We had thought, at the time we were doing our studies, that any of the gas transportation systems could have been started in 1977. This, of course, has proved not to be the case so far. There have been some changes in the state fiscal structure, so any studies we have done since the time we did them, have been overtaken by events related to the permanent fund. And so our analysis, while generally

valid, has been overtaken to some degree so I don't want to be held to specific numbers that we have generated.

The economic factors mentioned in the state report are the cost of service, net benefits to the United States as a whole, fiscal impacts, impacts on the private economy and cost of living. The report makes several points with respect to cost of service, based mainly on a study which I mentioned previously I had evaluated earlier, the Department of Revenue study by Dr. Knudson. A large number of variables affect any cost-of-service calculation. Mentioned in the study are throughput, that is the amount of gas that would be forthcoming per day; total capital cost, I might add -- including overruns, if any; the rate of return to equity required by the company; inflation which could be generally categorized as the general decline in the purchasing power of money and then real price increases during construction; interest rates available. And I might also add the duration of the project, which affects the financing risk, and which I expect Dr. Tussing will mention.

The Department of Revenue technical report mainly shows that the cost of service considerations which they mentioned are favorable to the Arctic Gas line are extremely sensitive to changes in many of the variables which determine it, particularly volume of throughput and

the capital cost. While Dr. Knudson does not treat the three proposals symmetrically, he does show that with Arctic Gas at eight-eighths of his proposed volume, that is the total throughput of, I believe, it was 2.5 billion cubic feet per day and with twenty percent cost overruns he is able to move the cost of service from One Dollar Eighty-One Cents per thousand cubic feet to around Two Dollars per thousand, while at seven-eighths of the volume or if the state gas were not available or if the throughput from the pipeline was not as expected, 2.5 billion, that moves the cost of service from -- I'm sorry. With seven-eighths proposed volume and ten percent cost overrun moves it to Two Dollars and Seven Cents, seven cents more; seven-eighths volume and twenty percent cost overrun yields Two Dollars and Seventeen Cents per thousand cubic feet. So that with only nominal cost overrun or changes in the volume of production which are within the realm of possibility, you can move cost of service all the way from One Dollar Eighty-One Cents per thousand up to Two Dollars and Seventeen Cents per thousand. That is holding everything else constant.

The Department of Revenue seems to imply by this -- from this to mean that Arctic is somehow less preferable; I think a more correct conclusion is that the cost of service is an extremely slippery entity. While the

calculations are worth doing as illustrations, we can't know how the cost of service will be influenced by the various parameters at this time, so I don't feel that the argument that for any of the lines ought to heavily lean on the cost of service. The relative costs of service mentioned in the Task Force report may well hold, that is that Arctic would have the least cost of service, I believe it is El Paso next and Alcan the highest. Whatever the relative costs are there are large differences between the two studies they mentioned in the Knudson report and the Pipeline Coordinator's office.

The net national economic benefit, however, they do not have depending on the cost of service. They have it depending more -- they have it depending on the amount that is paid for the gas which is Two Dollars and Eighty Cents, less the cost of construction, allowances for interest on funds committed during construction, working capital, operations and maintenance expenses, taxes paid to foreign governments. I presume only that allocable to the American earnings on Arctic.

At any rate, the analysis, again, is sensitive to the assumption used, particularly to the price of gas and the timing and staging of the projects. It is interesting to note that to get net national benefits

to come our superior for El Paso to the Arctic and Alcan proposals they require the following three assumptions, full production of gas, that is eight-eighths of the 2.5 billion cubic feet for the Trans-Alaska with 1983 production. Full production for Alcan, but later than El Paso, a year later in fact and Arctic Gas assumed to have a ten percent cost overrun and seven-eighths production.

Therefore, I'm not sure that the game was played exactly fairly with the proposals. However, I think it might be fairer to use the real schedules, whatever those happen to be at the moment, they seem to change from time to time, and the same throughput and the same cost overrun considerations.

In any case, I think that since Alaska could influence the benefits by its actions vis-a-vis any of the lines, and since the calculation is sensitive to the assumptions, we ought to be extremely cautious how it is used.

With respect to fiscal impacts, the results of this section depend on an earlier study by the State Department of Labor, Research and Analysis Section. Labor shows that the level of employment rises sharply in each case through about 1981, then levels off. This is supposed to include direct employment on the project,

induced employment in the state economy brought about by the increase in the direct workforce. I did not have access to the report at the time I was preparing my comments here, so I can't compare their model to ours, the Man-in-the-Arctic Program, the econometric model. Their usual procedure, however, has been to use the HRPI, that is Human Resources Planning Institute labor market model, which does not take into account the impact on employment of state spending of additional revenues received by the state as a result of the gas projects.

Our work in this area, which does take this into account through the state government sector, shows that employment impacts are somewhat larger for El Paso than they show, I believe they show around nine thousand and we show around twelve thousand in the year 1990, a little more than for Arctic, and for what it's worth, about the same as the Alcan project.

So we have minor differences about the construction period, but in the main we agree about the ranking and approximate relative impacts on employment and on population, I might add.

I have no real arguments with what the Department did with revenues and expenditures. I would note, however, three things. Spending on local services and state services probably influences migration and population,

especially in the El Paso case, where you have much larger expenditures possible. And in any case, El Paso proposes to use local communities more heavily than the other two lines so that you would probably have higher spending on local services.

All three routes show substantial front-end state deficits which will have to be financed by reduced services, higher taxes on someone, or both.

All three routes show substantial construction employment effects between probably 1978 and 1984. This may coincide with the timing of other major oil and gas developments, for example, the Gulf of Alaska off-shore, and I can foresee that some of these routes may well be competing for transportation links and dock space, particularly in the Gulf of Alaska.

I think that we can safely agree that if the LNG plant proves taxable by the state under its property tax that the rankings that are shown in the report are, in fact, correct.

With respect to impacts on the private economy, we have no fundamental disagreements with this section. The section is based on work done by ISER and by state experts.

With respect to employment, there is an importance of acknowledging there that the fact that the jobs are

available does not say "to whom". In order to really tell what the likely impact will be on state resident employment we would need to know the type of jobs available, including the requisite skills, the number and type of skills available in Alaska to fill those jobs and the type and effectiveness of "Alaska Hire" policies.

With respect to real income, no matter -- with respect to our work in this area, which is mentioned in the report, it seems like no matter what we do with respect to the relative throughputs of the lines, if the revenues of the state are spent in ways that induce migration, we found that it is impossible over the long run to increase the real per capita personal income of "Alaskans" and I say Alaskans advisably because that would include migrants as well as those people who are already in the state. It may well be that you could have a decline in real personal income even though everyone were made better off, in the sense that people who already live in the state could have increased incomes from building the pipelines, and those people who migrate to the state may enjoy increases in real income in spite of the fact that the average dropped. But we don't know what the answer is there yet. We should know in a couple of years. We are doing some work in the

area right now about distribution of income and economic modelling in Alaska.

Results from our community survey in Fairbanks show that economic benefits, however, were much more widely spread than anyone had expected prior to the Alyeska pipeline being built. So that might be something you want to take into consideration.

With respect to cost of living, the analysis in the report seems reasonable and straightforward and I don't think we have any quarrels with that.

I would be happy to entertain any questions at this time.

SENATOR RADER: Let me advise the committee that Commissioner Martin, as you recall when he terminated his testimony Monday, asked for permission to come back after the conclusion of all the testimony and to supply us with any information that he felt was pertinent and I understand that he has an observer here. So I assume that those parts of your report, Doctor, which take issue with the Task Force and the other information will be presented somewhat to the committee at least for some rebuttal and I wanted to advise the committee members of that prior to their going on with Dr. Scott's questioning. But this would be an appropriate time I take it, Dr. Tussing and Dr. Scott for questioning on Dr. Scott's presentation?

VII

ADMIN.

JOINT PUBLIC HEARINGS

of the

ALASKA STATE LEGISLATURE

on

SCR 3, 4, 5 and HCR 11, 12, 13

"THE PROPOSED SALE OF ROYALTY GAS"

January 31, 1977 - February 7, 1977

Juneau, Alaska

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Alaska State Legislature

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SENATE SPECIAL COMMITTEE TO CONSIDER THE SALE OF ROYALTY GAS

John Rader, Chairman
Mike Colletta
Chancy Croft
John Huber
Clem Tillion

HOUSE SPECIAL COMMITTEE ON THE SALE OF ROYALTY GAS

Clark Gruening, Chairman
Chat Chatterton
Joe Hayes
Joe McKinnon
Charlie Parr

SCR 3, 4, 5 Second Referral - Senate Resources
Third Referral - Senate Finance

HCR 11,12,13 Second Referral - House Finance

AGO 546284

JANUARY 31, 1977

SENATOR RADER: This is the time set for the joint hearings held by the Senate and the House relative to the Governor's proposals to the sale of royalty gas and the resolutions that have been introduced in both the House and Senate concerning those matters.

First of all, I want to introduce myself. I am Senator John Rader and to my left is Representative Clark Gruening. We are each chairmen of independent committees. This is not a joint committee, it is a joint hearing of two committees.

I'm going to introduce the Senators on this side and Representative Gruening will introduce his House members. I'll start with Senator Meland of Sitka, Senator Orsini of Anchorage, Senator Hohman of Bethel, Senator Butrovich of Fairbanks, Senator Poland of Kodiak, Senator Huber of Fairbanks, Senator Croft of Anchorage, Senator Tillion of Halibut Cove, and Senator Colletta of Anchorage. Mr. Gruening.

REP. GRUENING: Thank you. I'd like to represent -- introduce Leo Rhode from Homer at the end of the table, Merle Snider from Kodiak, Red Swanson from Nenana, Larry Carpenter from Fairbanks, and Bob Bradley from Anchorage, Russ Meekins from Anchorage, Chat Chatterton from Anchorage, and Joe Hayes from Anchorage, and Joe McKinnon

from Anchorage, and Charlie Parr from Fairbanks, and I'm Clark Gruening, the chairman of the House Special Committee to consider this gas sale.

SENATOR RADER: We had hoped that we would have a place at the table for every legislator who was interested and I -- in the Senate I asked for persons to let me know and only Senator Kerttula let me know. I do see some legislators in the audience that I would like to recognize. I see Representative Haugen, I see Senator Sumner, Representative Haugen stand up perhaps, Sumner, Representative Bill Miles, Senator Willis, Senator Bradley, and if there is anyone else here, and Representative Miller, Senator Hackney.

We will not take questions from the floor except for legislators. Any legislator who has a question though, whether he is seated at the table or not, will be permitted to ask questions of the witness if he desires. But, because we do want a full transcript of this, I'd ask the legislator to perhaps come forward and if there is an empty seat here, take it for such period of time as he is asking questions. I do want to extend that privilege to all of you who are here if you have any questions. We will not permit questions though from non-legislators. If you have a question, you are going to have to get some legislator to ask it for you or else it probably won't be

asked.

The -- we would like to have everyone sign in that is here. We want to keep a record of attendance, if we can, and who you represent. If you wish to testify, please leave your name with the person at the desk or with any of our staff members here. Elke Kallab, Elke would you stand up. Elke -- if you do wish to testify and are not the list, leave your name with Elke or search her out. If you give it to me, it may get lost. If you give it to Elke, why I'm sure it won't be.

We found out -- our original schedule was for two days here and one day at the Baranof. We have found out that this is available for three days so all of our meetings here are scheduled for today, tomorrow and Wednesday. I'm hopeful that both the House and the Senate will conclude their sessions so that we will be able to have an eleven o'clock session here starting tomorrow, going to twelve with an hour for lunch, coming back at one and going until four thirty or five or exhaustion wipes us out, whichever first occurs. But, of course, our meetings in the mornings and during the days will be subject to the House and Senate meetings on the hill and these committee meetings will of course be subject -- it has a lower priority than do those meetings. I expect, however, that we will be able to convene though tomorrow at eleven o'clock. Those

of you who are wishing -- yes. Those of you who want transcripts, would you leave your name with the court reporter. Prior to building you a transcript, we'll try to give you a price on it so you'll have a chance to back out. If you'll leave your name with her and an address, we will try to work out some sort of a situation here so that we can give you an estimate of the price on the transcript and then she'll contact you at the address you indicate and if you want to buy one, you can. I don't think we are going to be able to print up enough to handle everything at public expense, we'll have to look into that. But, if you want a transcript leave your name with the court reporter.

This room is over capacity, I'm sure. I'm going to ask that you refrain from smoking. We'll try to take a break at least every hour. I don't like to interrupt the witness in the middle of his testimony or a question -- a line of questioning that is being pursued, but subject generally to the convenience of the proceedings at the time, we'll try to take a break every hour to give you a chance to take a smoke and stretch your legs.

We have a tentative agenda that we have developed. It is only tentative. We'll take any witness out of order. We're here to accommodate you for your travel plans and your other commitments. We know that a lot of

you have things to do other than to be here. If you wish to be taken out of order, let me know and I'll try to accommodate you as soon as I understand what your problem is.

It's a public meeting, of course, and everyone is welcome to attend and everyone will be welcome to testify. I suppose that if it went on for three weeks there probably wouldn't be very many people here to listen to you, but there will be someone here to listen.

I can't think of -- Representative Gruening, can you think of any other remarks or ground rules we need to establish?

REP. GRUENING: I'd like to introduce Representative Al Osterback who is sitting on the Senate side but is representing us in the House.

SENATOR RADER: Incidentally, from the Senate's point of the side, we have both the Resources and Finance people on our side. They have referrals of the resolutions after the select committees and there may be some public testimony taken by those committees at a later date. That will be up to the chairmen of those committees to determine whether or not they need it.

I have been contacted by a congressional delegation and told them that I would read their testimony verbally into the record and therefore I am going to do that,

although I think that in some instances we will receive written testimony which will not be read unless it is absolutely -- unless someone insists on it, some committee member.

But, we have a wire from United States Senator Mike Gravel.

(Whereupon Exhibit 1 was duly read into the record.)

That exhibit will be exhibit number one. The reporter will not retype exhibits which are read into the minutes. We will make them exhibits and they will be xeroxed when we make our copies to try to save on the expense.

Exhibit number two, which the reporter need not copy but which will be appended to the transcript is a wire from United States Senator Ted Stevens.

(Whereupon Exhibit 2 was duly read into the record.)

And that will be exhibit two. Representative Don Young called me less than twenty minutes ago from Washington, informed me that he had directed that his testimony be hand carried from Washington and that it left Washington Friday evening. I have been informed since then that it was sent to Washington because of a telecopying process -- sent to Anchorage and that the airplane cannot

leave Anchorage and that the reason that that testimony is here is because of the Anchorage airport and not the Juneau airport. I'm sure we will receive that testimony in the course of the hearings and when we do, it will likewise be read into the record.

REP. GRUENING: Senator?

SENATOR RADER: Representative Gruening.

REP. GRUENING: If I might be permitted a brief remark, it seems to me that this -- these three contracts that are before us now represent the single largest sale of our natural resources since the Prudhoe Bay lease sale and I hope -- I urge the legislators to hold sacred no sacred cows in approaching the assumptions upon which this -- these three contracts are based. And, as the Senators have pointed out, the principal reason that we are considering these contracts today is to effect a political decision in Washington, not to raise revenue for the State. So, I would urge everyone to focus on at least what I believe to be the principal question, what are we giving up by entering this contract, if anything, and what are we getting in return for the State -- for the people of this state.

SENATOR RADER: Unless there are any further remarks, we'll go back to our schedule here. I'll ask Commissioner Martin if he would present his testimony and those of his

associates in whatever order he approves. Commissioner, how would you like to handle questioning?

COMMISSIONER MARTIN: I'd like to ask Attorney General Gross and Commissioner Gallagher to join me here and I'll introduce the other individuals, Mr. Chairman.

SENATOR RADER: Would you want us to defer until the end of your presentation for questions or ask questions as we go along?

COMMISSIONER MARTIN: I think it would be most useful because, as I'll explain, we have a fairly brief presentation, to defer questions until the end, and then just have a continuous question period after that.

SENATOR RADER: Does anyone on the committee object to that procedure, any legislators object? That will be the way we'll proceed then.

COMMISSIONER MARTIN: Is Mr. Gallagher here? I thought I saw him earlier. Do you want to come up, Sterling?

Mr. Chairman, I have spoken, as you know, previously to a joint meeting of the two special committees at least, and to both of the Chairmen of the two special committees and, as I understand it, we have some options for procedure, and I want to explain that before I begin. We discussed either having a prolonged briefing by the Administration in which as many as eight or ten individuals could participate and give really very detailed information

with regard to every phase of this as opposed to a more summarized presentation followed by questions. And my understanding of the consensus of those -- the choice between those two and which I checked with you earlier this morning, was that a more summarized statement of the administration's position, in view of the fact that we have already submitted a tremendous amount of written material to the committees, would be preferred. So, if that's all right, I'll proceed in that vein.

Now, my attention today is to first read a statement sent down by Governor Hammond, followed by a statement by Attorney General Gross, who is a chairman of the State's Gas Line Task Force, and then to -- then allow the committee to simply ask questions of all the individuals that are here. And, let me very quickly indicate who is here and how I think we can be of assistance to the committee's informational needs today. Governor Hammond has asked me to be a principal spokeman on this issue and to attempt to see that you get the answers that you need, both here and otherwise, and I'll be pleased to serve in that capacity. With me here today, in addition to Attorney General Gross, who is the chairman of the Task Force and who was also responsible for putting together our FPC case, is Commissioner Gallagher, who done a -- Commissioner of Revenue, who has done a great

deal of work on the economics associated with the various line proposals and with the royalty gas contracts. Also here, and I'll just ask these individuals to raise their hands so you can identify them, is Mr. Bob LeResche, -- Dr. Bob LeResche, who is the coordinator -- the Director of Division of Policy & Planning in the Governor's office and was basically the substantive coordinator of the comparative route study done on the gas line issue. Also here is E.Z. Gilbreth, who is the Director of the Division of Mineral & Energy Management, the Department of Natural Resources, who is responsible at least for representing here today, the work that the State has done on royalty gas demand and is also in charge of our effort on the unitization of the Prudhoe Bay field. In summary, he is in charge of our management function with regard to the Prudhoe Bay field.

Also here is Mr. Hoyle Hamilton, who is Director of the Division of Oil and Gas Conservation. Mr. Hamilton is in charge of the field operation for the State, pursuant to the State's conservation statute, and is the individual who is coordinating our work on the reservoir simulation study and other aspects of the performance of the reservoir.

Also here is Assistant Attorney General Fred Boness, who is the individual at the Department of Law

who coordinates legal oil and gas work, assisted me staunchly throughout the negotiation of this contract and is also the coordinator from Juneau of the State's work in the FPC case. He's really our man on this issue.

And finally, Jack Byrd, who is sitting on the end there. Jack is a -- I think safe to say a nationally known consultant. He is an attorney, a nationally known legal consultant in the area of natural gas. He is an FPB attorney and has served as our gas contracting consultant, particularly on matters of price and FPC regulations throughout the negotiations.

There are other individuals involved who -- to a lesser extent who can also be here to assist from time to time but this is basically the team. I might say, Mr. Chairman, that we really want to thank the committee for making an effort to consolidate its hearings. We have a number of individuals here who are going to be difficult to get in one room on very many occasions and we appreciate the fact that you allowed us the privilege of making at least our factual presentation on this in one -- in one instance. Mr. Byrd and Mr. Boness, particularly, will have demands on their time in the next couple weeks will make it very difficult to get our entire group together very often, but we'll try to cooperate with the committee as far as we can to see

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that we can get the people you need to be available. With that, I would like to read a statement that was sent down by Governor Hammond to the committee and then ask Av Gross to give a statement of his own.

"Members of the Committee, members of my Administration are here today to discuss a proposal of great importance to the future of the State. Because your review of this proposal should be as thorough as possible, I would like to preface the more detailed comments of others with my own statement. My objective is to lend perspective regarding the issues involved, and to define elements important to your ultimate decision.

Like the Native Claims Settlement Act, the Trans-Alaska Oil Pipeline and 17 D(2) Lands, the issue of North Slope natural gas transportation and use is a critical decision for Alaska. Present national emergy emergencies and last year's passage of the Natural Gas Transportation Act of 1976 leave little room to doubt that a national decision on the gas transportation system is imminent. The question is: what, if any, will, can and should -- what role, if any, will, can and should we play in that decision to best protect our own interests within the constraints imposed by overriding national interests?

After first analyzing various alternatives, my Administration concluded that the best, most expeditious

transportation system from both the state and national viewpoint was that which would take gas from Prudhoe Bay to tidewater in Prince William Sound. This legislature reflected a similar conclusion in a resolution adopted two years ago. Polls indicate that almost -- indicated that almost eighty-five percent of the people of Alaska stood solidly behind that choice. The congressional delegation concurred. Such support was not given lightly. Unlike the oil pipeline, the gas pipeline route had been widely discussed through the state, both in the media and through public meetings, before a decision was made. That decision is one which can be supported on principle as well as politics.

Having made the decision on which route to support, we actively participated in Federal Power Commission hearings; successfully advanced the unprecedented amendment to protect later state uses of royalty gas, and took our case to the people in the Lower 48 in an effort to offset the considerable opposition. After all, nearly all major distribution companies favored the Arctic Gas consortium. Mid-western states, which had sought a Trans-Canada oil pipeline, argued that the gas pipeline should go directly to them. After participating in this process for some time, and in light of legislative expression and congressional consultation, I felt it necessary to do more to gain support

for our position from outside the state. That conclusion led to the royalty gas contract you see before you now.

The major purpose of these contracts is to build a national constituency in support of the Trans-Alaska line while protecting and enhancing the in-state utilization of Alaskan royalty gas wherever possible so long as consistent with national needs. We believe the proposed contracts protect the state's interests as fully as possible under the circumstances. We are not, as some suggest, simply trying to buy lobbyists in Washington. That could have been done simply through hiring qualified personnel. The royalty contract does far more. It gives people throughout most other states an interest in seeing that the Trans-Alaska route is approved. A decision on this matter will ultimately be made by the President and the Congress. Their overriding concern will be in the national interst. Overriding national interest can be deomonstrated best if the largest number of people possible directly benefit from approval of the Trans-Alaska line.

Our actions in bringing forth these contracts are what I believe the people of Alaska, the legislature and the congressional delegation believed we should do. I suspect that if my administration had not negotiated the best contracts possible and advanced them under these

circumstances and then given them to you, we would surely be asked by many of you where the royalty gas sale proposals were rather than being questioned about proceeding. As your legislative resolution indicated to use "all resources at my command" to further a Trans-Alaska gas pipeline route. Certainly, there are politics involved in any such contractual agreements. However, there is nothing at all wrong with political forces being countered by political forces when the politics one uses coincide with principle. So long as we believe the Trans-Alaska route truly is in the state's and the nation's best interests, we would be remiss should we not garner what support we can so long as we do not do violence to propriety or principle in the process.

My instructions for our negotiators were to seek the best contract possible for the state to carry out the policies articulated and to do so on a time schedule which would allow the legislature the eariliest possible opportunity to review this alternative. After reviewing the results of the negotiations, I concluded it to be in the best interests of the state that this alternative be advanced. That decision won the endoresement of a broad spectrum of the Alaska public and the congressional delegation and was, as well, accorded approval of the Royalty Board as mandated by statute.

In negotiating the contracts, the State recovered a good price; it protected the future in-state use of gas; it gave the State the best opportunity to utilize and protect its royalty gas pursuant to the amendment we drafted and proposed to Congress for protection of our royalty gas; and at the same time we've gained support for the state's position on the gas pipeline debates. Moreover, the contracts are consistent with the direction the legislature gave to the administration when it not only indicated its support for the Trans-Alaska route but later appropriated money to aid in the negotiation of contracts.

Some concerns have been raised concerning the so-called "flexibility provision" in the contract. That clause would permit the state through the governor to change its position on the route issue at some subsequent time. Some assert that no flexibility at all should be possible and that the state should lock itself into an all or none position in support of the Trans-Alaska route. I think this is self-destructive, for I am sure that nearly every person in the state would agree that if we cannot have the El Paso route, the Alcan route is far more desirable than the Arctic Gas route. And they would want the State to be able to do what it can to gain the next best choice should our first choice be impossible or unwise.

Other persons suggest that while flexibility is desirable, any change of position should only be made with the concurrence of the legislature. Normally I have great sympathy with legislative participation in policy decisions of the nature -- of this nature and my record bears it out, but in this case you must recognize the realities of the situation. Our support for the Trans-Alaska route is strong and will not waiver unless and until it becomes clear that that route cannot succeed. That point, if it comes at all, will probably come at some time later in the pipeline decision--perhaps in the closing debate in Congress. Decisions will have to be made quickly if they are to have any impact at all. I can assure you that if I have to make a decision to shift our support from the El Paso route to the Alcan route it will be only after a clear consensus has emerged from our Congressional Delegation that such a shift was necessary and after a similar consensus had emerged through consultation with the State legislative leadership. We would all recognize it to be in the best interest, I think, if that -- in our best interest, I think, if that moment arose. But, reconvening the legislature and seeking a new full-scale debate on the question would simply be unrealistic considering that we might be dealing with decisions which would have to be made in literally hours or days. If there were time, I

would honor a request by the legislative leadership to call a special session, but I cannot support a requirement for a mandatory session under any circumstaces, for it would tie our hands unnecessarily and perhaps jeopardize the best interests of the state. I hope you will consider these contracts very carefully. I have tried to have them available for you at the onset of the session so that you might move quickly on them, but I do not want in any way to pressure you into a decision before you are satisfied that the contracts are in the state's best interests. At the same time, you know and I know the timetable of the federal decision, and waiting an unreasonable period of time before giving your endorsement to what we have done may indicate on a national level that our support is vacillating or, for that matter, that our support will not be translated into meaningful action in enough time to have an impact. I am sure you are aware of these factors just as I am, and thus will deal with the contracts reasonably and expeditiously.

I hope this brief review clears the air on certain aspects of the decision before you. Members of my administration will be available to you today and later to answer questions which led up to the contracts. I have instructed them to stay here as long as they are needed by the committee and to answer the questions you

have. Some of them will have additional statements to make concerning the contracts. And, the Governor expresses his thanks, Senator Rader.

At this time I would like to ask Attorney General Gross to make a statement, the only other prepared statement we'll be making today, which indicates the work that was done by the Gas Line Task Force.

ATTORNEY GENERAL GROSS: Thank you, Commissioner Martin. As the Governor has just indicated in his statement, one of the major purposes for the contracts before you is to build national support in favor of the Trans-Alaska pipeline route. I think it is fair to say that approval or disapproval of this contract by the legislature will be interpreted in large part as approval or disapproval of the Governor's decision to support the Trans-Alaska line. Since that is the case, it seems to me incumbent upon the administration to outline for you why we have come to the conclusion that support for the all-Alaska line is in the state's best interest. You have an enormous amount of material before you that has already been furnished by the administration to justify its decision, but it is perhaps fitting as we begin these hearings that I briefly outline how we have reached this point in the decision-making process.

As one of the first acts of his administration,

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Governor Hammond appointed me as chairman of the Gas Pipeline Task Force. The purpose of that group was to gather and analyze the available data on alternative pipeline routes and then to recommend to the Governor which route was in the state's best interest. The Task Force was composed of commissioners from the departments which would have involvement in the construction of a gas pipeline, such as Community and Regional Affairs, Revenue, Natural Resources, Highways and Commerce. Mr. Champion, the Pipeline Coordinator, served on the committee, as did Lowell Thomas, the Lieutenant Governor.

In candor, there were enormous pressures on the task force. A review of the files indicated that little, if any, prior substantive analysis had been done of the alternate route proposals. Accordingly, we had to develop the information on which our decisions were based from scratch. The members of the task force had little prior expertise in gas pipeline regulation matters or the kinds of decisions which were relevant to choosing a particular route. We had to gain that knowledge before we could make any kind of an intelligent decision. Finally, we were put under a lot of pressure by the schedule of events having to do with the pipeline route decision. The FPC hearings were about to begin and if the state was to take any meaningful position, it was necessary that we

make a prompt decision on what position we would take in those hearings.

We tried to arrive at a position fairly and honestly. By that I mean we tried to evaluate the data made available to us in an unbiased fashion. We did not try to reach a politically popular result just for the sake of that popularity. The Governor instructed us to reach a position that we could rationally support, and we knew we had to do that since if we were to promote our case before the FPC and in the national forum, a decision based purely on political considerations would be quickly and obviously exposed for exactly what it was. We may have made mistakes, Mr. Chairman, in our deliberations, but I can assure you that they have not been through lack of commitment or effort to do what was best for the state.

Initially we had but two alternative route proposals--the Arctic Gas route and the El Paso route. In analyzing those choices, we used information provided by the companies both to us and in their filings before the Federal Power Commission. That information was subjected to the scrutiny of various departments which evaluated the information with a view toward testing its authenticity. We commissioned an economic study on the alternative routes. Evaluating all the evidence, the

task force concluded unanimously that from both economic and environmental viewpoints, the El Paso route was clearly the best for the state. We recommended it to the Governor and he accepted our recommendation, committing the state to supporting that choice.

The reasons for the choice are, I think, now obvious, at least in retrospect. From an economic standpoint, the El Paso route generated a great deal of in-state employment during construction and created a number of long-term job opportunities within the state. The El Paso project meant a greater amount of capital investment in the state. It also provided opportunity for in-state use of gas, a matter of critical importance. The Arctic Gas route provided little lasting economic base for the state. Environmentally the Arctic Gas route intruded on the Arctic Wildlife Range, one of the last undisturbed wilderness areas in Alaska, while the El Paso route for the most part utilized an existing pipeline corridor developed for the Alyeska route. Every single major environmental group involved in this matter joined us in our support of the El Paso route as opposed to the Arctic Gas route. It was one of the few issues on which those who promote rapid development in our state and those who are strict conservationists agreed.

Finally, very real questions have been raised as

to whether the Arctic Gas route can even be built, at least in the forseeable future. Native land claims problems in Canada are very real right now. And, as we all know, from our personal experience, those claims can have very real impact.

Now, approximately a year after our initial decision and a good part of the way through the presentation of the case before the Federal Power Commission, a new route alternative developed. That was the route from Prudhoe Bay to Fairbanks, and then down the Alcan Highway. That is the route that is now known as the Alcan proposal, and it has some real benefits for Alaska. For instance, it permits in-state use of royalty gas (though it does not bring the gas to tidewater), and it provides a greater long-term economic base in the state than is provided by the Arctic Gas route. Environmentally the Alcan route uses existing pipeline corridors to Fairbanks and then follows the highway to the Canadian border, with minimal environmental impact. Environmental groups started to split with the surfacing of this proposal. Some of them now advocate the Alcan route.

The Governor asked at that time that the task force re-evaluate our position in light of the Alcan proposal, and we did so, using basically the same process as we used to reach our original decision. The task

force concluded after substantial study, including two additional comprehensive economic analyses, that while the Alcan route was far better than the Arctic Gas route, it still was not as beneficial to the state as the El Paso route. In long-term employment, for instance, the El Paso proposal will create nearly one thousand more jobs in the state than the Alcan proposal. On a net basis, the El Paso route will produce approximately Five Hundred and Twenty-five Million Dollars in income for the state treasury during the effective life of the line, as opposed to approximately Three Hundred and Fifty-seven Million Dollars for the Alcan route. Only the El Paso route will take gas to tidewater where prospective use of our royalty gas will probably be greatest. Moreover, from a national viewpoint, our analyses indicate that the El Paso route can give as much as One Billion Dollars more net benefit to the nation, primarily through the fact that more of the project is built with American labor and materials, and is subject to only United States taxation.

Environmentally the case between Alcan and El Paso is very close. The task force favored El Paso since it used existing corridor technology. Now, that is important, since it means that we can use the wealth of material that we have developed on rivers, tundra, and wildlife

as the Trans-Alaska pipeline was built. Moreover, we would, in effect, channelize our pipeline development in the state. But there are real benefits to Alcan as well. It is a purely subjective judgment and I would not seriously quarrel with any of you who felt that Alcan was the better environmental choice, but, in my view, it is not so much better as to countervail the substantial economic benefits which flow to the state if the Trans-Alaska pipeline route is selected.

As chairman of the task force, it was my basic function to coordinate the efforts of the various departments involved. I do not pretend to be an expert on the various studies which have been done, technical aspects of construction or difficult questions involving environmental matters. We have here today, however, people who can answer those questions, and Commissioner Martin and I can direct your questions to the people who can best respond to them. We are available to help you in any way we can in explaining what we have done and why. I think we have made the right decision and I hope we can convince you that we have made the right decision. Thank you.

COMMISSIONER MARTIN: Mr. Chairman, I'm -- having said a great deal on these contracts in prepared statements and the other night before Senator Gruening's committee, I'm not going to make a prepared statement in addition to

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that made by the Governor and Attorney General Gross, but I'm prepared to answer what questions I can and direct your others to any other individuals we have here who can help. Thank you very much.

SENATOR RADER: Thank you, Commissioner, Attorney General. Have we any questions from any members?

REP. GRUENING: Somebody has got to start here.

SENATOR RADER: Mr. Gruening?

REP. GRUENING: I think this goes to Mr. Gross. In the comparative evaluation it stated -- November of '76, there is a letter, December 2nd, 1976, to the Governor in which on page three of that letter, on the bottom of the third paragraph, Chairman Gross makes these remarks: "I think Alaska would agree that if we reached a point where support of the El Paso route as no longer feasible, the state should throw its support behind the Alcan route. The only real question is at what point." And then in the next paragraph you suggest a number of points at which that support might be switched, and one of them was the decision of the Federal Power Commission Hearing Judge. And that decision, as I understand it, will be made tomorrow, and I don't know what the decision will be, but let's assume that it is not favorable to the all-Alaska Route. Is it your position now that that is not an important stage at which we should consider the -- our

first choice or is it important as you see it?

ATTORNEY GENERAL GROSS: Well, it is certainly important, Representative Gruening. I think that since I wrote this letter we have had an opportunity to discuss with both the Congressional Delegation and the people involved in the effort in Washington, what the impact will be of an adverse decision before the Federal Power Commission. It is my impression, from discussing that with those people, that the fight will still be very much an open one at that stage, that the basic decision is going to be made by the President and the Congress, and that the issue will not be foretold by a Federal Power Commission decision even if it were adverse. So I would say at this point that an adverse decision would not cause me, at least, to recommend to the Governor a re-evaluation of our position.

Commissioner Martin has been more in charge of the Washington aspects of this and I think he would be more appropriate to answer that; but that would be my own reflection on what I consider.

COMMISSIONER MARTIN: I'd only add, Mr. Chairman, that I think the circumstances that exist now, after the passage of the Alaska Natural Gas Transportation Act, should be noted to be substantially different than that which would exist under ordinary certification processes. As that bill is

structured the FPC administrative law judge's opinion ultimately leading to an FPC decision becomes only a part on an overall structure which will involve a number of other federal agencies, the President and Congress prior to the decision. Whereas, under the ordinary circumstances the finding of the judge followed by the Commission would be determinative. So, I think that the circumstances change but I would want to add that we intend to look at that decision and we anticipate, quite frankly, that it will be lengthy, several hundred pages, and we anticipate that it will have a number of subtle and sophisticated points in it. So that I think that it would be very difficult now to say before seeing it what the position would be. But, standing alone I don't think that it represents a -- necessarily a single factor to change the state's position.

REP. GRUENING: In this new legislation, what role or what importance would you play on the presidential -- the President's decision?

COMMISSIONER MARTIN: Well, all of these are somewhat subjective judgments. My own feeling would be that the way the decision will be made, and I guess I say this from the perspective of my experience somewhat from the oil line as well as this present dispute, Mr. Chairman, is this, that my guess is that the President will take advantage

of the fact finding period set up in the bill utilizing the federal agencies as well as the FPC. He will then move toward a position on it without probably taking a final position and then work with members of Congress to see if the issue can somehow be brokered or somehow resolved between the two branches prior to the time that it goes.

So my guess is that the President is going to be very important but that he will not send a recommendation to Congress without having a fairly good idea of how it will be returned. His role is unquestionably crucial.

REP. GRUENING: What I'm trying to determine, Commissioner, is at what point, interpreting the Governor's remarks today that you read, at what point would he make a reconsideration? If I understood it correctly, he said in Congress. In other words, the President's decision wasn't as important to him -- or I'm trying to understand at just what point you think these considerations that Chairman Gross pointed out earlier are important.

COMMISSIONER MARTIN: I don't think that you can identify a single instance but I can give you some examples that would be the sort of thing that would be important. For instance, if we get an early indication that the -- if the President simply does what I suggest, he may not, and that is, takes a position simply within the next sixty or

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ninety days, stakes out a position and says "I'm going to support the Arctic route" or "I'm going to support the El Paso route", we will know something then that will be definitive. We don't know whether he will do that.

Similarly there could be an action taken in Canada, a definitive action which would give us an idea whether Canada has any capability at all to approve any pipeline through its country or whether it will act so as to facilitate it. And I really think that you're not going to get an answer as to a definitive point in time and this is what we think is one of the strengths of the contracts, that it puts us in a position where we can be somewhat flexible in response to that but at the same time have our basic position well established and well supported.

SENATOR RADER: Senator Croft?

SENATOR CROFT: Could I ask -- I'd like to get back to Attorney General Gross' letter of December 2nd. You said in the last sentence -- the last paragraph of that, "I feel there is every possibility that the Trans-Alaska project will eventually be selected for the transportation of North Slope gas." Do you expect Judge Litt tomorrow to in effect recommend the El Paso route?

ATTORNEY GENERAL GROSS: No.

SENATOR CROFT: What has happened to date to make you think there is every possibility that that route will be

selected?

ATTORNEY GENERAL GROSS: I think the indications I have, Senator Croft, primarily revolve about the Canadian situation. I think that the Canadian situation is going to be a great deal more formidable than the administrative law judge contemplates and that the land claims issue -- the national situation in Canada at the present time are going to create a climate in which a Trans-Canadian route of any kind is going to be difficult. And I think that will be a highly determinative force on a national level.

SENATOR CROFT: Mr. --

SENATOR RADER: Senator?

SENATOR CROFT: Unless somebody else has another question. I was going to ask in that regard that the Anchorage Times of Saturday had reference to a treaty that had been recently concluded with Canada and somebody had said that that treaty had no material effect on the pipeline debate. Do you believe that's correct and exactly what does that treaty do?

ATTORNEY GENERAL GROSS: I do believe that is correct but I think Commissioner Martin can better explain it if that is all right.

COMMISSIONER MARTIN: Well, I think that it has some effect. I don't think that it is going to be determinative in any way. That's -- the treaty that was signed and now

subsequently has to be ratified in each country, is basically a formalization of the ad referendum agreement that was made earlier and that agreement really doesn't resolve any of the difficult questions that confront Canada on this issue. It tends to be more of an agreement to agree than anything else. I can have Assistant Attorney General Boness describe the terms of that treaty, I'm sure you are already familiar with them, but I don't think that treaty in any way is an agreement for a Trans-Canadian pipeline, either Alcan or Arctic.

SENATOR CROFT: The reason I ask is because I had heard that there was going to be a move on the part of our congressional delegation to fight this because it did have implications. You would expect then no fight out of our congressional delegation as a result of it?

COMMISSIONER MARTIN: I would think that they might oppose it but my own indication is that they share the view that I just expressed regarding the treaty, that it essentially establishes more normalized working relations between the United States and Canada on sort of a broad range of issues, but it does virtually nothing to materially advance either an Alcan or Arctic route.

SENATOR CROFT: Mr. Chairman, would you expect that the administration in conjunction with the Congressional Delegation and the purchasers of the North Slope gas would

then oppose that treaty in Congress?

COMMISSIONER MARTIN: I really wouldn't take a position on that. Our position throughout has been not to obstruct relationships with Canada nor to highlight differences between Alaska or the U.S. and Canada on this issue. I think the bigger issue really is simply the Canadian self-interest and the internal Canadian problems in terms of approving it. But, without examining in detail, my preliminary guess would be no, that we would not make major efforts to oppose it, if any.

SENATOR RADER: Any other questions? Mr. Parr?

REP. PARR: Yes. I believe my question would be for Commissioner Martin. In reading the Governor's statement, Mr. Martin, the purpose of this is to build a constituency in the Lower 48. Now, the Governor in dealing with the reason for not getting legislative concurrence in his switch said that a decision to shift, and these are almost his exact words, would have to be reached quickly and perhaps in hours or days and therefore it wouldn't be possible to get the legislature back into it. I would like to know what credibility you think we would have if on July 3rd we are supporting the El Paso route and July 4th we are supporting the Alcan, not only what credibility we'd have but what credibility our presumed allies would have?

COMMISSIONER MARTIN: Mr. Parr, as I see it there are really two situations that might exist to change the state's position on this issue. One could occur any time and one could occur, as I see it, only relatively early in the debate. The one that could occur relatively early would involve the substantive merits of the routes themselves and that is the emergence of facts, whether those facts are deregulation of gas or other factors, which would just simply change the substantive judgment of Alaskans on which routes are in its best interest.

The second factor which I think could occur at any point, would be the development of facts which indicate that our first choice, El Paso, simply cannot succeed and that we would lose to Arctic, a third choice, unless we changed our support to a second.

Now, in terms of your question about credibility, I think that most of the early development with regard to new substantive aspects will happen probably during the time -- or a good part of it will happen during the time that the legislature is considering this issue and should be very much a part of our debate.

With regard to the second factor, I think that anytime we switch, based on the fact that El Paso can no longer prevail, we are simply -- we are not impairing credibility because we are not changing our mind about

which is the best route. We are simply saying that the best route can't succeed and we're changing our allegience of support to the one that is the next best in our interest. So, I think that either the State or the companies could make that argument.

REP. PARR: Then you would say that the people down in Tennessee or wherever who were supposedly writing their Congressman in support of the El Paso route would understand that they were being asked to switch the next day as to writing their Congressman to support the Alcan route?

COMMISSIONER MARTIN: I don't think that they would know, Mr. Parr. I think that it is a very difficult situation. I mean, there is no question in my mind that you have -- that your point is valid to some extent. The logical extension of it, however, is that we lock ourselves into a single avenue of support at this time and give ourselves no avenue to get out of it if circumstances do change.

REP. PARR: Thank you.

ATTORNEY GENERAL GROSS: Representative Parr, I think -- is it any more -- is it any different than in any political process where a position is reached where a compromise must be made which some person may not wish independently but, forced to it is, nonetheless, required to make a compromise? It happens in the Legislature, it happens in

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the Congress, it happens all the time and I don't think it is a question of credibility. It is a question of you seeking the best thing you can get for your constituents. View it to the extent you can and I don't think it is a question that will be not credible, it's simply dealing with reality.

COMMISSIONER MARTIN: Representative Parr, I'd like to add one other thing when you asked about your constituency in Tennessee. Under those circumstances they are not going to lose the gas if the position changes. I mean those same people who have been writing the letters are going to be getting the gas but getting it through a system which can succeed rather than through one that may be a hopeless -- you know, a loser and can't succeed at some later time. So those individuals will still have the gas supply.

REP. PARR: May I reply?

SENATOR RADER: You still have the floor.

REP. PARR: Well, in reply to Mr. Gross, I see his point and after all we all know that politics is the art of compromise, right? But, that is a little bit different from what I was talking about, I think. We were talking about persuading a bunch or ordinary people who are just -- who are not politicians but to support our cause by persuading their politicians, right? And I think that is

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quite a bit different from the fact that we in the legislature and in the Governor's office and everywhere else all have to accept compromise as a political fact of life. I think there is quite a little difference there.

ATTORNEY GENERAL GROSS: I think Commissioner Martin's point is well taken. If the compromise will still protect the interests of those individuals, I think they would support it.

REP. PARR: Mr. Chairman, well, of course and if that's the case, what we ought to do is make it pretty clear, "look, we want you to support whatever the State of Alaska wants supported, so you can get the gas. not that we want you to support El Paso so you can get the gas." Right? We were telling them that El Paso is the best route, okay?

ATTORNEY GENERAL GROSS: Right.

REP. PARR: And they are supposed to honestly believe that and try and persuade their congressmen, not just because they are going to get the gas because that is purely a selfish motive and if that is the way we are going to play it, we ought to know it. But I felt we were going to persuade them that El Paso was the best route and then we come along and say, "well, no soap, boys, now it's Alcan we have to go for." That's all I have Mr. Chairman.

SENATOR RADER: Mr. Chatterton?

REP. CHATTERTON: Mr. Chairman, Mr. Commissioner, on November 22, 1976, why the Alaska Royalty Oil and Gas Development Advisory Board met and did indeed approve your determination to waive the competitive bid process and subsequent to that why you as required by statute set forth some findings and conclusions. And I realize fully, Commissioner, that you were operating within a time frame, that you had to come up with something prior to the early portion of the first session of the Tenth Legislature. But, you in effect say that one of the rationales for not having any competitive bidding as far as intrastate use of gas is that no specific proposals for such purchases were forthcoming. Now, and in your judgment, how far on down through the future calendar time do you think that situation would remain in effect?

COMMISSIONER MARTIN: My experience thus far with the royalty oil and gas, Representative Chatterton, would indicate that rather than a highly competitive situation arising, what will happen is that a series of possible users of royalty oil or gas will develop. Now these may be small utilities, Golden Valley or some other electric cooperative, they may be municipal -- municipalities that go toward some gas system or a system that uses oil as a fuel for electrical generation or other purposes, or there may be large users that develop from major petrochemical or other

projects, and it may be that as those uses develop or we define uses that are beneficial to the state, that we can structure competitive sales to reach particular objectives but that they will be largely predicated on individual development or uses that may be competitive. For instance, in the case of Golden Valley Electric, it is very unlikely that we would expose Golden Valley Electric to a highly competitive sale which might be at the expense of consumers along with somebody else who had come in to compete with Golden Valley Electric. Now, we have not made any final determination on this but I think we'll see that situation confronted. So, I don't foreclose the possibility of competitive sales but I think it will arise in the context of a lot of individual proposed uses that will have to face a competitive sale on one of those proposals.

REP. CHATTERTON: My follow-up question, Mr. Chairman. Is it further and under your finding speaking to interstate sale of gas -- you say, "under present legal and regulatory circumstances a competitive sale based on price competition is not feasible because the price at which natural gas may be sold in interstate commerce is controlled by the Federal Power Commission." And, I ask you, Commissioner, how far into the future can you guarantee the citizens of Alaska that "present legal and regulatory circumstances"

will make it -- will keep the situation so that you cannot ask for competitive bids for interstate sale?

COMMISSIONER MARTIN: Well, I don't think I can give you a figure of guarantee and I doubt that you would force me to come up with it in a short period of time. Under the new administration I'm sure you are aware that the President has indicated his desire to move toward deregulation. Exactly how reliable that makes an absolute promise for deregulation is anyone's guess and I think it is something that might well be granted with our congressional delegation. I do think that the situation is unpredictable. The odds are now substantially higher in favor of deregulation occurring than they were before President Carter made that statement.

In terms of this contract, we would be again benefiting by prices realized from the Prudhoe Bay field if we went to a deregulated situation. I know that later in this week there is going to be additional testimony on the price provision that deals with deregulation and I'm hopeful that perhaps at sometime we can come back and have a discussion which I think will be complex and an interesting discussion on what that means. And, I think that there will be -- that we are largely protected under a deregulated or regulated situation to get the highest price from that field. I

will not tell you that there may not be circumstances that can arise that are unforeseeable at this time which may not make some differences and I want to discuss that with the committee. But, basically speaking, I think that this contract ties itself to the highest price, whether or not deregulation occurs.

REP. CHATTERTON: Thank you, Mr. Commissioner, thank you.

SENATOR RADER: Any further questions? Senator Croft?

SENATOR CROFT: I'm curious in regard to the use of political influence exactly where you expect that political influence to fall? Whom are we trying to effect?

ATTORNEY GENERAL GROSS: Political influence, I think the Governor's words, I think, are more apropos. I think he called it "building a national constituency". I think what he is trying to do, Senator Croft, is to give people in other states as well as Alaska, an interest in seeing the Trans-Alaska pipeline route approved. Now in -- as they are influenced, as they desire that route, hopefully their congressional representatives will also desire that route. Hopefully there will be more of a national constitutency as would influence the President in his decision. That is the type of thing we are talking about.

SENATOR CROFT: You don't anticipate these contracts having any effect on the FPC then?

ATTORNEY GENERAL GROSS: I think that frankly the contracts

have come too late to influence the FPC decision except as it indicates a commitment of the gas. But in terms of building a constituency for the pipeline, no. I think the FPC decision is probably already written.

COMMISSIONER MARTIN: Each of the buyers, Senator, did intervene in the FPC in favor of the Trans-Alaska route but I think beyond that it is certainly not a political situation with the FPC from here on out. They'll be participating in the standard legal procedures of the FPC and doing so on behalf of the Trans-Alaska route.

SENATOR CROFT: As an educated guess, is it fair to assume that you anticipate that Judge Litt tomorrow will basically rule in favor -- or recommend in favor of the Arctic route and that the FPC in its full commission hearing, which decision they have to make prior -- or on or before May 1st will likely follow his recommendations?

COMMISSIONER MARTIN: Well, the former question with regard to Judge Litt's decision is difficult to guess. The only way that you can guess is the way in which the Judge has asked his questions and made his statements during the hearing. In my own view that has tended to follow a strong bias toward the Arctic route and some dissatisfaction with both of the other alternatives. So, I -- my honest personal expectation is he will rule in a fairly complicated decision probably, in favor of the Arctic route

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and the decision will be somewhat complex beyond that.

In terms of the FPC following his decision, I think that's just too speculative to really guess. I believe there is one and possibly two seats vacant on the FPC. The way those seats are filled will have a tremendous impact on that and I think that the information that is produced outside of the FPC proceeding from here on out will also have an impact on it, and that is one case in which I think the State will want to participate. As you may know, during that period of time the ex parte rule is waived for some purposes and a great deal of information will be made available to FPC commissioners in addition to that which is made available for the record itself. So, I just think it is too unpredictable to know.

SENATOR CROFT: Do you think then that these contracts may have an effect on the FPC?

COMMISSIONER MARTIN: I think they'll have a substantive effect and I think it will be important that the people that we have working for us will be able to produce new information and hopefully develop better information on the routes but I don't think they will have a political -- To answer your questions in terms of politics, I doubt if it will have a political effect. I think, Senator, it is very important to say a couple things here to at least give my own personal opinion with regard to this idea

about politics being at the heart of it. I don't share that view. First of all, someone said earlier, I think it was Clark, that what is important is what you get and what you give up. In terms of what you get, I think we spend too much of our time really dealing with thinking the only thing we get is political support. As I see it, there are really four major things, some of them having sub-parts that we get. One is, we get a good price for this gas and we get it, I think, according to a term that gives us the best protection we can get aside from getting a premium. We may at a later time be able to get a premium and I'm -- I've said that throughout this entire consideration. It's a matter of whether or not you want to withhold this action waiting for that time to possibly arise. It is not here now and we can't get it now, but we get a good price.

Secondly, we get a contract which very closely follows the theory that Mr. Moody advanced last year and that could be followed to protect our royalty gas. We get in-state protection of gas by a total take back provision, which I think most people agree is extraordinary in its coverage of future in-state uses and to protect. That may or may not be something we can accomplish later.

Third, we get, I think, a reasonable exercise of the rights that we gain through the amendment that passed the Gas Transportation Act and last years Congress. There

has been some disagreement over whether or not this is the way and the time in which that should be exercised. I personally believe it is a reasonable way and a reasonable time to exercise it, and I think the Congressional Delegation agrees with that.

And, fourth, and only fourth do we get the support for the pipeline that we are talking about and even there, that support while it has a political aspect, that is it builds a constituency in a certain area and it puts people on our side working for it. It also has a substantive aspect, Senator Croft, in that these companies, Tenneco and Southern, are companies with great resources in terms of their substantive capability, whether it is LNG or offshore operations and the way in which they merge into the El Paso system in a logical distribution pattern. They bring a great deal more to it than politics. So, I think that while it is unquestionable that there will be political or other -- you know, something to be characterized as political support. There is much more to the contract than that that is of benefit to the state.

SENATOR CROFT: Mr. Chairman, could I reply to that? The phrase "political support" did not originate with me.

COMMISSIONER MARTIN: I understand.

SENATOR CROFT: I don't know whether it did with you or the

Attorney General but on page twelve of the Governor's speech dated November 12th, he says, "Gaining political support at this critical stage of the pipeline proceedings is the major reason for acting now on royalty gas, but there are other reasons also." And then on page fifteen he says, "The primary objective of this sale is to gain additional support for the pipeline route the State supports."

COMMISSIONER MARTIN: I understand that and I think it is fair to characterize it as a primary reason, or the primary reason, but I'm trying to make it a point ---

SENATOR CROFT: The primary reason is political support?

COMMISSIONER MARTIN: That -- in my view, it is not. I think in my view there are many reasons and they are all of somewhat equal character. I think the Governor said that, and that is his view, that he thinks it is a primary reason.

ATTORNEY GENERAL GROSS: I think you may be getting into a semantic difficulty here. I think what you read, Senator Croft, said the reason for selling the gas now is to generate political support, and I think that's unquestionably accurate and the Governor stressed it. That is the reason we are doing it now as opposed to doing it a year from now, that a year from now it will have no impact in gaining us any support for our posiiton

in the Trans-Alaska pipeline dispute. I think Commissioner Martin is stressing that the contract itself whenever made, also has certain highly desirable features to it, which he has stressed. And I think that is absolutely accurate too.

SENATOR CROFT: Could I ask one more question and then Mr. Chatterton has one. To what extent does either the Federal Power Commission or the United States Congress have authority or the possibility of allocating this gas wherever it goes anyway? Couldn't they simply say, "we approve this route and we determine that 2.5 billion cubic feet a day are to be sold east of the Mississippi River"? And doesn't -- I mean, doesn't Congress have the power to allocate that gas rather than them having to say, "We're going to approve a route because then a supplier may buy it through some contract"?

COMMISSIONER MARTIN: Well, Senator, I think you know partially what the answer to that is. That is the stuff with which interstate commerce clause battles are made between states and the federal government. Under some circumstances I would say, yes. Under the -- as you know, oil is allocated and I don't suppose that there is any over-riding reason that they couldn't do that. The circumstances would have to exist to do so.

Let me just point out on the other side, though,

that we were successful in drafting a proposal and our delegation was even more successful in gaining the passage of the amendment which gave Alaska the right to utilize its gas in-state. So that I think all you can do is judge that subjectively as a political possibility. In other words, a legislative congressional possibility. Right now, I think, that given the gas shortage in the Lower 48, how we react, responsibly or not to that in Alaska, has a great deal to do with that. How other gas producing states react has something to do with that.

In my view, the passage of the amendment was a hopeful sign and it may be one that we can capitalize on and protect future in-state uses. But -- the question is simply, can they do it? I would say, sure.

SENATOR CROFT: I have some additional questions but I notice Mr. Chatterton wants the floor.

SENATOR RADER: First of all, anybody who has not yet asked a question, who would like to, we'll open it up to everyone before we get to -- Mr. Chatterton, then.

REP. HAYES: Mr. Chairman?

SENATOR RADER: Mr. Hayes?

REP. HAYES: Commissioner Martin, just one item of clarification. The statement regarding the primary purpose of the contract which had to do with political considerations, that was the Governor's position and not yours?

COMMISSIONER MARTIN: Yes, sir.

REP. HAYES: I read it in the transcript of your Royalty Oil and Gas Development Advisory Board of November 22nd, where I got the impression that it was your opinion.

COMMISSIONER MARTIN: My view is that -- just to clarify it, Mr. Hayes, is that all of these purposes are extremely important and that is one of them. Whether it is not the most important or not, or the primary purpose, is that I think it is subjective judgment. I think each of them are important, in a combination they make up a very good argument.

SENATOR RADER: Mr. Chatterton?

REP. CHATTERTON: Thank you, Mr. Chairman. I'm sorry, Mr. Commissioner, but I would like to recall your memory and see if you still stay. Going back to those findings that I referred to that you made following the November board meeting, why you do say that the "primary objective of the proposed" -- "presently proposed sales to improve and strengthen the position of the state with respect to the decision process for the system to transport North Slope natural gas" and I gather --

COMMISSIONER MARTIN: Well, Mr. Chatterton, I'd stand by that statement.

REP. CHATTERTON: Yes, I think that is what you said here.

ATTORNEY GENERAL GROSS: Mr. Chatterton, as one who has been

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involved in this from the Gas Pipeline Task Force point of view, I think when you say "political influence", what you are really saying is that it is a roundabout way of saying any influence. This is a political decision which is going to be made in the larger sense. A political decision as to policy consideration clashing to produce a decision as to where this pipeline route is going to be built. If the state is going to have any influence in this, it is going to have to have political influence in this. That's -- we either have the choice of doing nothing and watching it happen, or we have the choice of becoming actively involved and trying to influence the decision. The Governor made the latter choice.

SENATOR RADER: Senator Poland, then Senator Bradley.

REP. BRADLEY: Representative.

SENATOR RADER: Representative Bradley.

REP. BRADLEY: You don't know what an insult that is.

SENATOR RADER: I didn't mean to insult you, Representative. Senator Poland?

SENATOR POLAND: As long as we are on this political issue, one of the things that has bothered me about the switch provision in there is what incentives do these three companies particularly have when they're going --as I read the contract, they're going to get the gas no matter what route.

COMMISSIONER MARTIN: You have made a common error, Senator Poland, I believe in reading the contracts, because they will not get the gas no matter which route it is. I have talked to a number of legislators who have made the same error reading the contracts.

The gas will only be given -- if they are supporting the position that the state supports and if that position prevails so that if the state never changes its position from El Paso and Alcan is certificated, none -- these contracts will simply be void.

If the state changes its position to a second route, let's say Alcan, and one of the companies refuses to switch at the time the state does so and then Alcan prevails, or the other route prevails, they similarly lose the gas. So, the only circumstances under which they get gas is if they are supporting the state position and if that position prevails. Under all other circumstances the contracts would be void, so they have an undeniable incentive to be with the state on the prevailing position.

SENATOR POLAND: Excuse me, Commissioner, I didn't express myself well because I understood that the state had to switch its position for their contracts still to be in power. But, if the state does -- I mean, they have no incentive to particularly work to hold the state on the all-Alaska position.

COMMISSIONER MARTIN: I would think they would have the incentive of wanting to prevail since that is the position we are going to take and the position we believe would prevail.

SENATOR POLAND: Mr. Chairman, I have one other question that I would like to ask.the Commissioner.

SENATOR RADER: You still have the floor.

SENATOR POLAND: The state has the right to take back whatever gas it needs for in-state use, including the exchange of Prudhoe Bay gas for other gas elsewhere in Alaska. If the exchange gas is used in Alaska and including liquefaction of the gas provided the liquid gas is used in Alaska, now, does this mean that we cannot sell gas to a third party for liquefaction and export?

COMMISSIONER MARTIN: Let me ask. Yes, that is right. I wanted to make sure that I had followed your question.

SENATOR POLAND: Then if we want to use those things we have to go into that business ourselves?

COMMISSIONER MARTIN: I want to be sure I understand your question, Senator Poland. Would you run that by one more time? I'm not sure I understood it.

SENATOR POLAND: Does this mean that we can't use -- we can't sell to a third party for liquefaction and export?

COMMISSIONER MARTIN: That is right, we could not do that. In my view that is right but we could sell for liquefaction

and use. The statement we make is protected from all in-state uses except liquefaction for export. What you are suggesting is a way that we might essentially cheat that provision. What we have sold in these contracts, I have made it clear in all my statements, is the -- the one thing we have sold is gas that is surplus to state needs and the sole judge of state needs is the state itself through its statutory process. But, anything that's surplus the state needs by our own choice is committed under those contracts and what you're suggesting is a way to -- essentially to surrogate that bargain, if the bargain is to sell gas that's surplus.

SENATOR POLAND: In other words, you don't consider that the state needs the liquids?

COMMISSIONER MARTIN: This has -- I assume -- I didn't understand your question to have anything to do with gas liquids, Senator Poland. I can discuss that -- I didn't think -- were you asking about gas liquids?

SENATOR POLAND: No, I asked on this other and then I'm also interested in -- what about the liquids? Because your answer --

COMMISSIONER MARTIN: Well, the liquids have been the subject, I think, of some misunderstanding. Under the terms of this contract Alaska has a full right to the liquids from this gas. Let me give it to you in practical terms. It

first has a right -- and this has nothing to do with the notice provisions under the contract, it has a right to take those liquids and do whatever it wishes with them, including exporting them or any use in Alaska and to take them at any point where those liquids are taken from the gas, whether it's in Alaska or outside.

In addition to that, it has the right to take the liquid -- the gas off itself and take the liquids from the gas and to use it in Alaska. The only limitation is not in the contract but it is a practical economic limitation as to whether or not those liquids will actually be taken out in Alaska or whether or not the state can justify the building of a plant to take out the liquids itself for only the royalty share. Now, it's been suggested and I think by several people, that one of the things the state did not do in this contract is to use the contract to coerce in some way or to negotiate for the fact that the liquids of all of the gas would be taken out in Alaska. That is accurate, we did not. But I can assure you that we would not have been able to get this contract if that were our objective. Now, if the legislature believes or other believe that that should be our objective, to force the eight-eighths on us -- every-one to take out their liquids in Alaska, we can take a run at doing that but that is not one of the objectives

of the contracts. Other than that, we have a full right to our liquids anywhere they come out or we want to take them.

SENATOR RADER: Representative Bradley?

REP. BRADLEY: Commissioner Martin, is the State of Alaska engaged -- and this is somewhat in following the four or five or six or eight questions regarding political clout, is the State of Alaska embarking on some sort of unprecedented new morality or new ethics or something that is unusual that's ever been done -- that's never been done by any other states. I mean it doesn't -- I'm -- this is somewhat rhetorical. It doesn't appear to me that way but some people have commented on bad morality and some people have -- and of course when people mention politics, I guess in a lot of cases they're talking about it as being bad. I don't feel that way and I don't think some people do but -- are we entering into some sort of new era of sin regarding our resource development?

COMMISSIONER MARTIN: Well, I have never heard the point raised by anyone until raised by one -- raised by Lieutenant Governor Boucher at the Royalty Board and raised just in the last week. Those are the two occasions on which I heard the issue raised in the whole last year or so that this issue has been discussed and quite frankly has been very openly known.

My own view of that is, no, we are not entering into any new period and we don't intend to. I don't think there is a specific precedent for a state doing what we have done. Let me try to answer the question this way in terms of what was involved. First of all, other states don't fool around with -- you know, even the kind of contract we have, which is I think a reasonably complex answer to a problem that is itself complex, they just simply spend money and they pay people money to go down and lobby people in Washington and lobby people elsewhere to do what they want.

Secondly, I think it is very important to remember that we are not coercing the national will using our resources. If we were in a position of saying, "we want the Trans-Alaska pipeline and we are not going to let our gas leave this state to go to the people in the Lower 48 under any circumstances except the certification of this route", I would think then we would be in a coercive and somewhat morally questionable position. What we're saying is we're expressing a preference for the route we want and we're making a contract that would award gas only to companies that help us get that route. If the route fails the contract -- the only implication of that is that the route fails. The implication of it is not that the people in the Lower 48 who may need it,

are deprived of some portion of our surplus gas, so we're not coercing.

And finally let me just say that there is only certain tests of what may or may not be politically or ethically acceptable actions and I think that a year of public debate on which that question simply was not raised, followed by what I would say is ongoing consultations with our Congressional Delegation with regard to their perception of the way this would be heard in Washington. This indicated to me that they consider it to be a highly proper and in fact, a desirable course of action and not one, which at least to them, has indicated moral questions.

SENATOR RADER: We have gone a little bit more than an hour. We will take a ten minute break and we'll strictly limit it to ten minutes. We will bang it back to order in ten minutes sharp. We're adjourning -- or recessing.

(Whereupon the hearing was recessed at 3:30 p.m. and reconvened at 3:40 p.m.)

SENATOR RADER: Representative Rhode has to leave the hearing and asked to be permitted to ask a question. Mr. Rhode?

REP. RHODE: Thank you, Mr. Chairman. I have just one question and I'll be satisfied with a short answer. Under the present law, as I understand it, we have the privilege of taking our one-eighths share of the gas out of this

line at any place and anytime. Now, if this contract is not approved -- or I should say, if this contract is approved and the Congress repeals that privilege, where do you stand with this contract?

COMMISSIONER MARTIN: Representative Rhode, the Congressional amendment indicates that we have that right and it orders the Federal Power Commission to approve any contract that does that. If we have approved this contract and if the amendment is repealed prior to the time we get that FPC approval, it's our legal belief that we are not protected, that we would then have to rely on FPC approval without the amendment. That is still possible but the chances of it being approved at that point are substantially less.

SENATOR RADER: Mr. Gruening had an exhibit, I believe.

REP. GRUENING: I have an exhibit but I would like to ask some questions based on facts that appear in this. The exhibit numbered exhibit three is based on Tenneco's interstate natural gas pipeline market areas and it has some figures on the states that are served and the amount of gas that they provided these states. And based on that the staff for the House Special Committee has come up with some figures that show that Tenneco's share of its twenty-five states that they serve is about ten percent. In other words, they provide about ten percent of the natural gas to these twenty-five states in 1975.

Tenneco's share of royalty gas under these contracts, based on those same figures, would be less than three-tenths of a percent. Now, that is fifty percent of our royalty gas. You put that in juxtaposition with the fact that there is twenty trillion cubic feet consumed in the United States in 1975, what impact is this going to have on building a constituency? It appears to me -- doesn't it -- it appears to me and does it appear to you, Commissioner, that the amount of royalty gas we're committing really is infintesimal when you are trying to deal with the energy gas shortage problem that we have?

COMMISSIONER MARTIN: I think you can only answer that in terms of the -- you know, rather than looking at the numbers and I do agree with your analysis. I'd like to see the figures but I understand what you are saying, three trillion cubic feet. And, in fact the entire Prudhoe Bay, which is let's say twenty-six to thirty-one trillion cubic feet, about one years supply in the United States. People forget that. We're very limited by the importance of any amount, getting our royalty amount. But the true measure of it is the level of interest and the level of support it genders and it seems to me that in terms of the effort that it has generated and the support that it has generated and the interest it has

generated, we're making it go pretty far, but we can't be right, we can't make it go any farther than the basic amount and that is somewhat limited. That is about all I can say.

REP. GRUENING: Commissioner, unless the -- you know, the emotionalism of the crisis that is presently in the Lower 48, you know, upsets Congress to the degree that they don't look at these facts, won't Congress really look at the total energy picture and determine that if they are going to solve the gas problem, it is not going to be through, you know, picking a pipeline route, but reallocating the gas on a major basis as legislation is already introduced to do?

COMMISSIONER MARTIN: I mean it is a subjective judgment. I think that that is a possibility but right now we have a gas line procedural act that sets up an exactly opposite procedure to reach a decision on the route. So, that if you have to bet on what is the most expectable thing to happen, I would put my trust in the fact to carry out the terms of the gas line procedural act and try to reach a decision on the route. Now, whether or not allocation comes with that, I don't know. It's -- it's intangible.

REP. GRUENING: What I'm trying to get at though is what are we actually receiving by selling the gas now? In other

words, I understand your concern and I think the contract really has addressed itself to a lot of the points in terms of price, but even the best attorneys can't see six, seven, ten years in the future. So, if we're getting very marginal influence -- in other words, if Congress looks at it and says, "this isn't going to make it -- a lot of difference, this commitment one way or another" and this constituency really won't exist.

I'm trying to determine whether we really are building a constituency.

COMMISSIONER MARTIN: Clark, I've never tried to change what I think was the basic position on what we get in terms of support for the route. It is a subjective judgment. It could be analyzed, as you have done it, by trying to figure out the amount of gas as it compares to something else or it can be done by talking about whether Tenneco's a good or bad company or any other number of ways. I can only judge it myself in terms of what it appears to be doing and what it appears that it would do in that decision. And I've tried to apply the judgment of many people doing it. To me, the fact that our Congressional Delegation has to make that fight thinks that it is one of the most important things that we can do and they believe that it is crucially important to win the debate is a very important factor and goes beyond what

we can find on paper to demonstrate that it is not an important factor. So what we get, it seems to me, is more than just the figures on the paper but what people think they can make out of that. Right now that appears to be important.

REP. GRUENING: Will the companies' own decision on which route to support have an effect? I relate back to Senator Poland's earlier question in that what is the incentive of these companies to lobby for the first choice, El Paso, when in fact they know that the state would accept a certification of the Alcan line. I mean I don't think logically or reasonably we'd reject that certification if it was the only one and why not -- what's -- I mean, won't they be in the drivers seat in determining which one they want --

COMMISSIONER MARTIN: Well, we would accept it. We would accept it but the question is whether or not we will be supporting it at the time. That is what we're left with. It may well be that we conclude throughout the procedure that El Paso's in our best interest and that the companies stay with us throughout and that that route simply loses.

I made an error earlier and I want to correct it. I said that the contracts would terminate. The contracts may be terminated rather than they would terminate. It's policy that we would terminate it and I said it that way

because if it's policy then that would be the case. But under any circumstances, they're under incentive to support the state position because they must be with that position when it prevails.

ATTORNEY GENERAL GROSS: If I might add to that, the Congressional Delegation, Representative Gruening, can shift its support to an Alcan route without the Governor shifting his support. That the result that even if an Alcan route prevailed in Congress, these companies would not receive the royalty gas.

SENATOR RADER: Any further questions?

REP. GRUENING: Not at this time.

UNIDENTIFIED VOICE: Would you explain that again, please?

ATTORNEY GENERAL GROSS: Sure. The Congressional Delegation could in the end end up voting for somebody supporting an Alcan route. If the Governor did not formally shift the state support under the contract to the Alcan route, these companies would not receive any gas because they would not be -- they would not be in support of the route that the state would be supporting and that route would not be successful. So long as the state stayed with support of the El Paso route.

SENATOR RADER: Representative --

COMMISSIONER MARTIN: I think --

SENATOR RADER: Excuse me, sir.

COMMISSIONER MARTIN: I was just going to say that I think that is an entirely appropriate question to ask the buyers and I'm sure you will, in terms of how they're basing their activities and their judgment. There is no question in my mind that based on the activity that has already been undertaken and based on the preference of the buyers and based on what would be done -- you know, even during the time that the legislature is working on this, that a case for support of the El Paso route is being put together. It has been put together basically without any difference of opinion from many people in the state for some time.

I think questions about how difficult it is to change are appropriate but nevertheless we think we may reach that time.

REP. GRUENING: I have just a comment on -- the hypothetical that the delegation would be for one line and the Governor the other is pretty improbable. If I understand what you said earlier is that if the delegation -- whatever they say goes as far as you're concerned, they're --

COMMISSIONER MARTIN: No.

REP. GRUENING: No?

COMMISSIONER MARTIN: What the Governor said is pretty clear. He said that we may reach a time at which it is appropriate to change. If it looks like El Paso can't prevail and

we'll lose to Arctic without -- unless we switch our support to Alcan. He'd base his decision to change on the consensus of the delegation and legislative leadership and gave his pledge in his statement, as I understand it, to call a special session after consultation with the legislative leadership if time permits.

ATTORNEY GENERAL GROSS: I suppose as a scenario you are suggesting that the companies behind the scenes could be working in support of an Alcan route, which they hope would ultimately prevail, under the assumption that eventually the state would have to come over to that when they saw that the El Paso route would collapse. I think the state would probably take it amiss if it found that the people who were receiving the gas under the contract who had been committed to supporting a Trans-Alaska route were actually working under the scenes to support an Alcan route. I think that would probably affect the state's decision as to what it did and I don't think the companies would in any sense do that. I don't think that they would act in such a fashion.

REP. GRUENING: I can't believe the state in a myth would then forego the opportunity -- In other words, you are saying that it would -- if it found that, it would not -- it would reject the contract, if it found that they weren't living up to snuff, in your view?

ATTORNEY GENERAL GROSS: Well, I suppose what you are asking is would the state approve it after the fact. I mean if the Alcan proposal was then approved by Congress, would the state switch its support so it could give the royalty gas to these people. If that is what you are asking I can't imagine why that decision would be made just for that. I don't know.

SENATOR RADER: Representative Chatterton, I'm going to tend to go to persons who have not previously asked a question, however, Representative Chatterton did want to have a follow-up on something that occurred before the recess and then I'm going to start recognizing persons who have not yet spoken. Representative Chatterton?

REP. CHATTERTON: Thank you, Mr. Chairman. Commissioner, I sense that there is a consensus of agreement amongst this group with your statement that the primary objective of these gas sales contracts are to strengthen our end in the decision making process that you get an all-Alaska line. Just before we broke for coffee I very admirably -- I think I heard you speak to the point that you would in no way want to coerce any decision as far as Alaska gas is concerned to the South 48. Now, as I say, I think that is admirable and I share that position with you. Now my question to you, Mr. Commissioner,

is very simply this: That if subsequent testimony before here develops that the city gate price in Columbus, Ohio, would be lower by some route other than the all-Alaska line, would you still favor these contracts?

COMMISSIONER MARTIN: Well, I don't know.

ATTORNEY GENERAL GROSS: Can I respond to that, Representative Chatterton?

REP. CHATTERTON: Please.

ATTORNEY GENERAL GROSS: For one thing, I think that the price in Ohio probably is going to be lower by another route than the all-Alaska line. I think that the evidence which has developed indicates that the delivered price of the gas down below will probably be the cheapest by the Arctic Gas route, next by the Alcan route and finally by the El Paso route. So, the decision already has been made to make -- to support that and that is for a number of reasons. Some environmental, having to do with environmental considerations other than purely economic ones, the other having to do with political problems with building the lines themselves. Now the Arctic Gas, for instance, the model for Arctic Gas is constructed under the assumption of certain provisions for construction -- Arctic construction, using snow roads. Our people in the state government believe that that is a totally unfeasible way of constructing the

line and that as a practical matter if Arctic Gas is certificated they will end up spending a great deal more building the line than they anticipate spending at this time, that their cost overruns will be substantially greater and that therefore their cost of delivery will be substantially more.

Similarly, the political problems in Canada may mean that the lines may not be able to be constructed until many years in the future, beyond the point at which the gas under the El Paso proposal could be traveling southward. So, price is one consideration. An additional factor is the point that construction of an all-Alaska line will be using American labor and materials, it will be constructed wholly within the United States and the net economic benefit of that for the country is higher than using a gas Arctic proposal. So, there are other economic benefits to the country than just the price of delivered gas.

REP. CHATTERTON: Thank you.

SENATOR RADER: Representative Meekins?

REP. MEEKINS: Commissioner Martin, following up on what Senator Poland asked you about, the liquefaction, invoking the take back provision in order to commit our royalty gas to a third party for liquefaction and export, you indicated, as I understand it, that that would not be

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possible in this contract. Is that correct?

COMMISSIONER MARTIN: That is right.

REP. MEEKINS: What about taking back our royalty gas for purposes of using -- to then recommit it to a third party in order to give an incentive for the location of a petrochemical industry?

COMMISSIONER MARTIN: We could not take it back if they subsequently exported it but we could certainly take it back to be used in such a facility.

REP. MEEKINS: But we could not -- for instance, if that exactly was our purpose, to increase the incentive if necessary, for a location of a petrochemical industry at tidewater for export to the Lower 48 or elsewhere, we could not do that under this contract?

COMMISSIONER MARTIN: That is right and that's a very -- I think a very important question. It is one of the alternative courses that I think ought to be very carefully considered by the legislature. I tried to point this out before. What we have committed in this contract and it's a fairly -- in other words, I said this last year to this committee. You really have to sell something in order to get anything back. Now, the only thing that we have committed is whatever gas is surplused to any state needs in the future and is going to be exported. So that the only -- the only really meaningful arrangement that will

be difficult to enter into with regard to that surplus gas in the future is one where someone comes to us and says "we will build you a petrochemical plant in five years if you will let us export your surplus gas for five years and then use it." That we would not be able to do but what we would be able to do is to take it back and commit it to that plant in five years, as soon as they are ready to build.

Incidentally, we have looked at -- in the oil situation we have looked at a couple contracts and we are still actively looking at them, where they proposed to do this kind of thing. In other words, to take an export for a period of time and then tie it back to a -- what I'd say a possible refinery at some later time. And, at least thus far we haven't found anything that looks like a good deal for the state.

REP. MEEKINS: Thank you.

SENATOR RADER: Representative Rudd?

REP. RUDD: Mr. Martin, I would like to follow up on Representative Rhode's question having to do with the possibility that Congress would repeal the Alaska exemption.

SENATOR RADER: Representative, would you speak a little louder, please?

REP. RUDD: I'd like to follow up Representative Rhode's

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question on the possibility that Congress will repeal the Alaska exemption. If that happens, does it depend on Congress as to whether or not they make it retroactive or would our contracts, if we had entered into them, then be void?

COMMISSIONER MARTIN: Well, let me be very clear. We don't believe as a legal matter that simply entering into the contract now gives us any special protection. We believe we not only have to enter into the contract but we have to advance it to the FPC using that provision in order to gain protection. Congress could do basically anything it wants and there is no reason -- at the time that it repealed it, it would act retroactively. My feeling would be that if it wanted to repeal it, it would vary. It would not be likely that they would be in a mood to make it retroactive to pick up this contract.

REP. RUDD: But you feel even if they don't make it retroactive that our contracts are in danger at that point?

COMMISSIONER MARTIN: Well, I discussed this the other night with the House Special Committee. It's again a subjective judgment, what the risk of repeal of that provision is. I made the statement that Congressmen have said they are going to try to repeal it. I have no question but what some attempt will be made. Whether or not it will be successful is a purely subjective judgment and I've tried

to poll our delegation on that on a continuing basis and they have no strong feeling for it other than the fact that they believe that an attempt will be made and that there is some risk of repeal.

REP. RUDD: And may I ask you, how much weight did this possibility of repeal carry in your negotiations in the contract? In other words, how much weight did you give to the idea that you wanted to get something started before --

COMMISSIONER MARTIN: It carried -- it carried very little in my personal opinion, Representative Rudd. What it did do, not the threat of repeal, but what the provision did was change somewhat my position on the issue of the contracts themselves. This is one reason I stress other values of the contract other than the political aspects. Last year I testified before Senator Rader's committee and others that I was quite skeptical about the meaning of any of these contracts because I thought that they had almost no chance of ever being realized because it was doubtful the FPC would ever approve of a take back provision absent some Congressional assistance.

But once Section 13(b) was enacted, it increased substantially, in fact it increased almost to the extent of making it virtually certain, that we could get approval of such a provision if we could put one together, get

it advanced and approved and put it before the FPC while the provision was in place. But, it came along late enough that it really didn't change the nature of the negotiations a great deal. We were working on the contracts and quite frankly if we had finished the contracts and Congress had not acted to put that provision in as they did in the closing hours, I would -- we might be advancing the contracts to the legislature right now but I would be saying to you quite honestly that they would have a very low chance of being approved in the FPC. Now I can say to you I think they have a very good chance of being approved in the FPC.

REP. RUDD: May I ask just one more?

SENATOR RADER: Certainly.

REP. RUDD: Do you think that there is an element of time that is involved here, that we must move rapidly?

COMMISSIONER MARTIN: Judgment with respect to time again is subjective but I personally think there are two things to be said. One, I think that we have a responsible attempt together to try to utilize the benefits of that provision. I think that the way we have done it is responsible and I think we're capable of selling it. Obviously our delegation agrees because they think they can live with the results of this contract and preserve the amendment. Whether or not we can wait and bank on the

fact that the amendment will stay in place and go to some other kind of arrangment is simply a calculated risk that everyone will just have to take.

SENATOR RADER: Senator Huber?

SENATOR HUBER: Thank you, Mr. Chairman. I think my question is mostly for Guy.

SEANTOR RADER: Senator, you are going to have to speak up. I am certain they can't hear you.

SENATOR HUBER: All right, Senator, I'll speak up. I think my question is mostly for Guy. We have -- in the gas contracts themselves there is a provision that says pretty close like this, that there is no front end money but that whatever the highest price paid by anybody that is allowable by the FPC or if in case the FPC isn't controlling it, whatever the highest price is that is paid to any of the producers in the field will be what the price is to the Alaska royalty share. Is that roughly correct?

COMMISSIONER MARTIN: I think so. Let me defer to our two price experts. They're with me on that.

SENATOR HUBER: Well, in effect that says that if anybody else who has a share that is proportionate to ours, let's say that ARCO has twice twelve and one-half, they probably have got a little more than that, or twenty-four percent, and they get Fifty Million Dollars of head end money.

Proportionately if any head end money is allowed by anybody, shouldn't we have had a provision that also bounces back and says that we'll get the highest price per cubic foot, no head end money unless anybody else gets head end money, if anybody else gets head end money, we'll get a proportionate amount in accordance with our percentage. Wouldn't that protect the State of Alaska a lot better on price?

COMMISSIONER MARTIN: No, we don't have such a provision and it could be something that could be negotiated for, Senator.

SENATOR HUBER: Is it still negotiable?

COMMISSIONER MARTIN: Well, not under the present circumstances. I would say that it would have to be capable of being passed through in the rate base. I will tell you this, that if that could not be passed through either in the ARCO situation or in ours, these contracts would not be possible. In other words, the company -- we may be able to negotiate some other kind of a deal but I don't believe we could have negotiated these contracts -- included that provision unless it could have been passed through totally.

SENATOR HUBER: Well, Mr. Chairman, I --

COMMISSIONER MARTIN: And it is not legal to pass it through now.

SENATOR HUBER: I could foresee the possibility under deregulation that they may allow front end payments and in which case other people would quickly negotiate them, being they don't have them, and we would be left out in the cold at the lower price. And it don't look like the contracts protect us sufficiently in that area.

COMMISSIONER MARTIN: I don't think the terms of the contracts as they are presently drafted would include that. That is right, sir.

SENATOR RADER: Senator Croft?

SENATOR CROFT: Commissioner, before we leave the subject, you made the statement that no front end payment could be built into the rate base. Is that -- is that statement actually correct? Aren't there circumstances in which it can be built into the rate base?

COMMISSIONER MARTIN: The -- yes.

SENATOR CROFT: And in that regard we have not gotten the highest possible price for our gas, isn't that correct?

COMMISSIONER MARTIN: Jack, do you want to answer that?

MR. BYRD: Under the present FPC rules --

SENATOR RADER: Mr. Byrd, why don't you sit down and identify yourself for the record? You'll be the first new voice here and --

MR. BYRD: Thank you, Senator. I'm Jack Byrd from Kansas. Under the present FPC rules if front end money is advanced

and included by the pipeline to advance freight rates, then you -- whoever sells the gas takes a penalty on the price.

SENATOR CROFT: That is right, but what as to companies that are not regulated by the FPC?

MR. BYRD: On intrastate purchasers?

SENATOR CROFT: Right.

MR. BYRD: They could still do it.

SENATOR CROFT: So there could have been intrastate purchasers not subject to FPC regulations who would have bought this gas and could have paid us front end money --

MR. BYRD: Still can, under the contract.

SENATOR CROFT: And there are utilities in California that could do that?

MR. BYRD: Well, no, not in California.

SENATOR CROFT: Where are they?

MR. BYRD: The only intrastate purchaser you would have would be in Alaska and you could still sell -- withdraw gas to an intrastate purchaser in Alaska and demand front end money, if you want.

COMMISSIONER MARTIN: And you could not do that and sell to -- as you suggested, we disagree that you could do that to anyone in California because the transportation would be regulated, Senator, and the same provisions would apply.

SENATOR CROFT: The transportation, but would the distribution

with the utility itself, if it bought the gas not for resale to somebody else, would that sale itself be regulated as well as the transportation tariff?

MR. BYRD: The only provision I know of in which you can do that now would be under order 533, the transportation provision. The direct sale to an industrial customer for a high priority use, not for resale, a distribution company cannot do that.

SENATOR CROFT: But somebody that used it themselves could pay front end money?

MR. BYRD: Right. They could pay a premium price, they are exempt from regulation under the FPC.

SENATOR CROFT: Thank you.

SENATOR RADER: Representative Hayes -- excuse me, were you through with your --

MR. BYRD: One other point, the transportation of any such moving of gas from Alaska to California would have to be certified by the FPC. They would have no control over the price paid if it was not for resale and it was used for a high priority industrial use.

SENATOR CROFT: A higher price than what we have in these contracts could be paid in that situation?

MR. BYRD: Yes. But we have a provision in here that if any of our working interest owners sells theirs under that kind of a rule, these -- then our prices go up.

SENATOR CROFT: Yes, but whether they do or not, we could have sold our gas conceivably -- legally sold our gas for a higher price than what we have in these contracts.

COMMISSIONER MARTIN: Only by pursuing a completely different objective. We don't deny that, Senator. I mean, the fact is that we could have chosen a number of different objectives including not selling and waiting to do it later after deregulation. So, we think there are a number of possibilities in not carrying out these objectives we're doing it.

SENATOR CROFT: I understand that. But if I could, just so that we understand the policy questions that are involved, this sale does involve a sale of our gas at not the highest possible price?

COMMISSIONER MARTIN: That is a great overstatement, Senator Croft.

SENATOR CROFT: But isn't it correct?

COMMISSIONER MARTIN: No. It's correct but in the context of a number of other things. It's correct in the context of selling the gas for other purposes in this, but selling it for the purposes that we have attempted to carry out here, we believe that we have gotten the highest price. If we sold it for other purposes in which we subjected all other considerations to price, I think it is possible we could have gotten a higher price, yes.

SENATOR CROFT: As I understand it, if we sell it primarily for political purposes, we got the highest possible price.

SENATOR RADER: Representative --

COMMISSIONER MARTIN: You are still wrong, Senator. I mean I think he is wrong factually, Senator. Maybe we ought to respond. Let me ask Mr. Boness to do it. He is characterizing my answers.

MR. BONESS: Senator Croft, the FPC regulates two things. It regulates transportation and it regulates the sale. In a direct sale -- do not have to have -- a direct sale is not regulated. In that sense you seem to be suggesting that the FPC -- the higher price could be paid or front end money could be paid. However, the FPC has the power to prevent that kind of sale from taking effect by virtue of its control over the transportation aspects of the pipeline. The Transco case was a case which involved essentially that set of facts, where a sale took place, the shipment of the gas was to be over an interstate pipeline to be sold -- to be delivered, I believe, between Texas and New Jersey. The Federal Power Commission said they don't like the terms under which that sale takes place, therefore we are not going to approve the transportation. They had no authority over the sale itself but they did have authority over the transportation.

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Whenever you are talking about moving the gas outside of Alaska, you're not within the realm of 13(b), and the Federal Power Commission would have authority over whether or not to approve the sale. They couldn't regulate the price but they could absolutely preclude the sale.

MR. BYRD: Plus the fact that under the contract, if Atlantic Richfield or one of our -- one of the lessees up here sold royalty -- or sold their gas under 533 and got a higher price, then our gas from those leases would escalate up to that price.

COMMISSIONER MARTIN: Jack, but Senator Croft's question was going to our gas.

SENATOR CROFT: My question is, regardless of what they do with ours -- with theirs, what could we have done with ours?

COMMISSIONER MARTIN: Yes, I understand.

SENATOR CROFT: And as I understand the answer, it is we could have gotten a higher price but Commissioner Martin feels there were other factors that weigh into the decision that means that it was not in our interest to do it, and secondly, it might have been unlikely that we would have gotten a higher price. It is legally possible.

COMMISSIONER MARTIN: That's -- yes.

SENATOR RADER: Mr. Hayes?

REP. HAYES: Thank you. I was wanting to pursue that line of questioning that Senator Croft was just pursuing, regarding just how much we might be paying for -- by giving up alternative sales that might have some front end money involved for this political clout that we're going to get from the three gas companies that are purchasing our royalty gas. But it is probably not a figure that you can put any -- that you can put an exact number on, however, I think testimony indicates that under certain circumstances that we are giving up some -- something of value. Whatever that is, I don't know, but we are pursuing this on the basis -- that there is no front end money possible on the basis that the payment of front end money for interstate sale would not allow the incorporation of the front end money in the price scheduling. But, isn't it possible that -- I'll ask this to Commissioner Martin, isn't it possible or conceivable that a purchaser for interstate sale purposes might be willing to give up to the State of Alaska a portion of his anticipated profit in the way of front end money, regardless of whether he's ever passed it on? And in that event there is a possibility of getting the premium price.

COMMISSIONER MARTIN: Representative Hayes, yes. I think it is conceivable that we could have structured a

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situation where maybe even in a -- you know, maybe a competitive situation or maybe a situation where we simply just solicited people to do that, that we could have gotten some amount. In other words if the question is how much would some interstate buyer eat of their proceeds, I think the answer -- our determination basically is that it would be generally quite a small amount and secondly that it was certainly not possible with these buyers. And quite frankly, it was not consistent with at least the purpose of the contract which had to do with getting the best and strongest support for the pipeline route.

I might just say that our process in attempting to do that was to try to work with the available buyers we have and then to consult pretty much continuously with the delegation of others to try to see who could give us the greatest amount of help. So that trading all those things off, I don't think we got a realistic expectation of getting a small enough front end.

SENATOR RADER: Any members who have not yet asked questions, first?

SENATOR HUBER: I'd like to pursue this same thing.

SENATOR RADER: Well, Mr. Carpenter has not yet had a question. Mr. Carpenter, unless you want to waive --

REP. CARPENTER: I'll yield. I'll yield to the Senator.

SENATOR HUBER: Well, I think we was to a point, Mr. Chairman, and I'd like to pursue the same thing being I started this.

SENATOR RADER: Proceed.

SENATOR HUBER: We have picked our purchasers that we have contracts with that are now going for approval from a certain group of purchasers. These are pipeline transporters, not users, for instance. A user has different rules applied to him. If we had sold six percent to Pacific Gas and Electric and six percent to Wentworth Brothers for making into methanol and certain other things and certain other people -- for users there is different set of rules applied. Would you care to discuss that and have you shown in your deliberations consideration for these other type of contractors -- or these other type of purchasers?

COMMISSIONER MARTIN: Only to this extent, Senator, that we dealt to some extent with everyone who came to us with an offer to deal with us. We made some tough decisions as to who we would work with. To finally go through, and we consulted broadly to try to get the ones that could do the most good. These are the ones that ended up in our final judgment being that. Now, we're willing to stand with that. We did not consider Wentworth Brothers nor did Wentworth Brothers approach us with the idea of

buying under these terms and adding their support to the pipeline that we favor, nor the other one you mentioned.

SENATOR HUBER: I'm trying to get back to the basic consideration of whether we're getting the highest price, which this contract says we are. What it really says is that we're getting the highest price from a certain class of buyer only, those who are in the pipeline transportation distribution business, and cannot enter into -- by FPC rule, cannot enter into another phase of the business. Isn't that right?

MR. BYRD: Whoever bought it would have to have the certification of the FPC to get it transported, and if you'd sell it to Pacific Gas and Electric for boiler fuel you'd never get a certificate.

SENATOR HUBER: Well, I didn't say for boiler fuel, you said that.

MR. BYRD: I don't know what they would do with it. It would have to be for a high priority industrial use and not for resale.

SENATOR RADER: Mr. Carpenter.

REP. CARPENTER: I'm departing from the present line of questioning.

SENATOR RADER: Did somebody wish to pursue this line of questioning, or were you through?

SENATOR HUBER: Mr. Carpenter yielded to me, Mr. Chairman,

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and I thank him very much. So we can continue.

SENATOR RADER: I think Mr. Meekins wanted to pursue the same line of questioning. You have the floor, Mr. Meekins.

REP. MEEKINS: Thank you, Mr. Chairman. Just to clarify that then, there are trade-offs here involved, and there are some things we give up in order to have this contract. One of those, I understand, is a small premium (in your view), a fairly small premium, if that premium comes out of profits of the companies because it can't be passed through into the rate base; is that correct?

COMMISSIONER MARTIN: Under future circumstances, the size of it is unknown.

REP. MEEKINS: If there was deregulation?

COMMISSIONER MARTIN: These questions, you know, stand in the present time frame. It may well be under deregulation there are different terms in the future, we could restructure it and do something else. That has to be balanced against how important it is, how important the gas line decision is to the use of the amendment in Congress and so on. So our view is that for now this is a good alternative. It may be that under changing circumstances that the premium could be larger, or the price could be unregulated.

REP. MEEKINS: Right. That's a possiblity; we don't know it as yet ---

COMMISSIONER MARTIN: That's right.

REP. MEEKINS: -- whether that's going to be the case. But in any case, that small premium, in your view a small premium, is one of the trade-offs, and I'm not quite sure if the higher price by sale to users or not -- I seem to get contradictory information -- on the one hand, it seems that the FPC would not approve transportation of such a sale, and on the other hand it seems like they would. I'm not sure what ---

COMMISSIONER MARTIN: I think Mr. Byrd's answer is the proper one, for certain high priority users they would have a chance of getting approval of the transportation. For most users, and certainly any large scale ones that are not pricrity, they would have virtually none.

REP. MEEKINS: So what you're saying is it is conceivable to some scale to get a higher price if that sale was to a high priority use and, therefore, it would be approved.

COMMISSIONER MARTIN: Yes, it's possible, and it may have been possible to accomplish, but we had no indication that it was and no offer.

REP. MEEKINS: Thank you.

SENATOR RADER: Any further questionsalong this line? Senator Croft.

SENATOR CROFT: When was the decision that prohibited

building advance payments into the rate base?

MR. BYRD: It became effective November 5.

SENATOR CROFT: Of '76?

MR. BYRD: '76.

SENATOR CROFT: So that it is true that if this sale had been entered into possibly a year ago we could have gotten a higher price?

MR. BYRD: No. That November 5 date affected only advance payment or interest free loans that were made prior to an order that came out abolishing it, but it was the end of 1975. But there were a lot of advances, advance payment contracts, that still had not been executed, or advancements had not been made. Those were not abolished. Then the order coming out effective November 5, in 770-A they say that if the producer draws those down and the purchaser puts them in rate base, then the producer has to decrease his price, pay the carrying charges on it.

SENATOR CROFT: Then is it correct that if these contracts had been entered into in 1975 we could have gotten a higher price?

MR. BYRD: It would have been legal to extract ---

SENATOR CROFT: Front end money.

MR. BYRD: -- an advance payment.

SENATOR RADER: Any further questions on this line of

questions?

SENATOR HUBER: Just one, Mr. Chairman.

SENATOR RADER: Senator Huber.

SENATOR HUBER: Then in a deregulated system, and we look like we're headed toward deregulation now, some of the gas that will be in the deregulated system will be gas that has had front end money paid on it from Prudhoe Bay gas that's had front end money paid on it, and is also paying a certain rate to the field gas, which is apparently what we're getting, and if we had just held our gas until deregulation we could sell it for any price we wanted to make up for that, couldn't we?

COMMISSIONER MARTIN: Yes, assuming, Senator, that deregulation occurs, that we can structure the kind of contract that allows us to take back, and that that contract is approved, then you can be in a similar circumstance and you get more money and sort of have, you know, guns and butter at the same time. But you have to make all those assumptions to get there, and I think some of them are at least speculative.

SENATOR HUBER: These early sales, the amount that goes in is a very large amount of the sale price too, isn't it?

COMMISSIONER MARTIN: I'm sorry?

SENATOR HUBER: These early sales that were made that were approved, the front end money really amounts to a large

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amount.

COMMISSIONER MARTIN: There were some large advance payments, that's right.

SENATOR HUBER: Thank you.

SENATOR RADER: Representative Gruening.

REP. GRUENING: Commissioner, if, given the fact we have an active Congress allowing us to take back our gas for in-State use and if we assume that the primary goal was not to affect a political decision on the line, how long could the State wait safely to decide what to do under contract or how it wanted to sell its gas?

COMMISSIONER MARTIN: Mr. Chairman, there's only a subjective answer to that question. It could be years or it could be terminated during the next year. It seems to me that what we have now is a good alternative to take advantage of, and it may be that we want to pass that one up and try to structure another one.

REP. GRUENING: If I understand what you were saying earlier, we don't gain any rights by entering the contract in terms of this amendment. I mean, the amendment is there.

COMMISSIONER MARTIN: We only gain rights by having the contract approved by the FPC at a time that the amendment is in place. So our question is, how long will we have the amendment in place, and I made it very clear the other night that I'm not trying to create an atmosphere

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of fear that it will be repealed. I honestly don't know if it will be repealed. I'm almost certain an attempt will be made to repeal it, and what we have is an opportunity now to take advantage of it while it's in place.

REP. GRUENING: Do you read that amendment as allowing the FPC to do anything other than approve the take back provisions in the contract?

COMMISSIONER MARTIN: Yes, I think they might be able to approve -- well, let me ask to be certain of that. I think they would be able to approve something of a sale. They could approve a direct application, couldn't they?

MR. BONESS: They could approve.

COMMISSIONER MARTIN: I guess the answer is, there are other formulations that they can approve.

REP. GRUENING: Well, like price. But I'm talking about the take back.

COMMISSIONER MARTIN: No, I'm talking about the take back. I mean, I think that there would be other ways to approach them other than a sale configuration, but I'm not certain what those would be at this time. I'm not saying there aren't other avenues that you could approach the FPC with using 13-B. The question is really, how long you'll have the ability to use 13-B and whether or not this is a satisfactory way or not to

exercise the privileges. If this one were approved, putting aside all other things, it would give the State unprecedented protection for its royalty gas never before enjoyed by any state; there's no question about that. Whether or not we could do it in a better or more successful way, I don't know. It's pretty hard for me to imagine a more comprehensive coverage of future in-State use than this one. I can think of a few ways to do it, but not very many.

REP. GRUENING: Despite that do you think there's a danger that the FPC may not approve?

COMMISSIONER MARTIN: No, I think that 13-B pretty much mandates FPC approval.

REP. GRUENING: Where the slippage might occur is in their approval of the price, the pricing arrangements under the contract; is that what you're referring to?

COMMISSIONER MARTIN: I'm sorry if I'm not making myself clear, Mr. Gruening.

REP. GRUENING: No, I understood what you said before, but if that last statement of mine about the pricing isn't correct ---

COMMISSIONER MARTIN: Would you repeat it? I'm sorry, I didn't understand.

REP. GRUENING: I do understand correctly that as you see, the FPC would have to approve the take back provisions

in this contract, these contracts, under the Congressional Act.

COMMISSIONER MARTIN: Right.

REP. GRUENING: Is there a problem then with the pricing provisions of the Act in terms of the FPC approving them?

COMMISSIONER MARTIN: I don't see any, Mr. Chairman.

MR. BONESS: Again, the amendment addresses the problems related to transportation aspects of the FPC's jurisdiction. Even though the State is not subject to FPC jurisdiction for purposes of sale, the FPC could have prevented the State from getting, either effect to the take off provision in the contract or entry into the contract because it didn't like the prices the State was getting; the State had extracted a price higher than the price which the FPC approved. They could have prevented the transportation aspects of it. The amendment, Section 13-B, prohibits the FPC from doing that with respect to transporting the gas for intrastate uses. There is no problem with respect to the FPC regulating a sale which is the price provision, and under the amendment we're free with respect to both taking off and the price. Absent the amendment, we have to convince the FPC to authorize the transportation of the gas for use in the State.

REP. GRUENING: Reading the amendment, do I understand

correctly, the FPC could disapprove pricing arrangements?

MR. BONESS: No.

REP. GRUENING: Under the contract, they cannot?

MR. BONESS: Not under that amendment. They have to give effect to the transportation and they have no other basis for disapproving of it.

REP. GRUENING: Maybe I should follow this up because the last part of that amendment says that the FPC shall only review the justness and reasonableness of the rate charge for such transportation.

MR. BONESS: Yes, I apologize. I should have picked up on that was what you were concerned about. What it addresses is the notion of the transportation charges for moving the gas, say, as far as Fairbanks or as far as Valdez. Obviously, intrastate transportation of gas is going to affect the overall tariff for everybody else, and the FPC is given authority to review that rate and make sure that it's just and reasonable. That is really for the State's protection and also for the protection of all the other shippers on the line, to make sure that costs are allocated between interstate and intrastate shipping in a just and reasonable fashion.

COMMISSIONER MARTIN: Rather than going to the price paid for the gas itself.

MR. BONESS: But it's like the price of a ticket for moving

on the line, is what we're talking about, not the price of the sale of the gas.

REP. GRUENING: But do you see any danger, other than the fact we're losing, maybe losing options on dealing with which route we want, in delaying then a decision on how we want to sell the gas? Put aside the question, just for a moment, of which route we're trying to affect; is there any danger in delay, because I understand it you don't buy the theory that without the amendment that there's much advantage in getting the FPC to approve a contract?

COMMISSIONER MARTIN: Well, I don't reject it, but I don't think that -- you know, Dr. Moody thinks that's a controlling theory, and I don't think it is. I think there are still problems, but I think it's a valid theory, it's something that could be tried. You only made one exclusion. You said that if we exclude the purpose of helping the line.

REP. GRUENING: Yes. I know that's a major exclusion, but ---

COMMISSIONER MARTIN: Even if you exclude that, then there would be a great value in attempting to take advantage of 13-B before it's lost. There would also be an advantage, some advantage, I would think, in this contract over others in terms of price. I'm not saying we couldn't do better, depending where our objectives are,

but there are advantages in each of those four categories I indicated you would be giving up. There are also improvements that you might seek in another direction if you take out one of the objectives. If you take out the political assistance objective, you might be able to substitute another one.

SENATOR RADER: Mr. Carpenter now.

REP. CARPENTER: Thank you, Mr. Chairman.

SENATOR RADER: You've been very patient.

REP. CARPENTER: After all this time, I really wish that my question were an exciting one, but it's not. It relates to a technical provision in the sales agreement, in Article Five, which addresses quality. In Section One we mention that the gas to be delivered by the seller to the buyer at the delivery points shall conform to the quality spectifications, etc. But in the preceding paragraph, Article Four, Section Four, we say the seller shall retain the right to receive all liquids removed from the gas prior to its delivery to the pipeline, etc. My question is this: if the liquids are removed as provided in that section in Article Four, I understand that the quality specifications will drop because the btu content will change. Doesn't Section One of Article Five negate Section Four of Article Four?

COMMISSIONER MARTIN: Representative Carpenter, I've heard

that concern expressed before, and we've looked at it. Mr. Boness, I think, can answer that question.

MR. BONESS: Yes. 5.1 deals with the delivery point, which is a point on the North Slope prior to the time the gas will be put in the pipeline, and our gas will be at the same quality, wherever our delivery point to, as the gas the producer is moving along that stream and, therefore, we don't have to do anything special to it. Once the gas is put on the pipeline to move south we will have the opportunity to take that gas off and change it without being in violation of 5.1, because 5.1 addresses only the question of the quality of gas at the delivery point.

REP. GRUENING: I see.

COMMISSIONER MARTIN: We looked at that carefully, and when I heard it the first time it sounded like it was a good argument. But it looks like it only applies to that one point.

REP GRUENING: I see.

SENATOR RADER: I have one question, myself. Do you have staff that will be able to analyze the decision of the Trial Judge if it comes out today or tomorrow and be able to report back to us, at least in a summary sense, the day after tomorrow perhaps, as to whether or not that decision does, in fact, substantially affect the

posture of the situation?

COMMISSIONER MARTIN: You are looking at the group that will probably try to do that, and Mr. Byrd, and Mr. Boness and others will probably try to do that, and we'll try our very best to get a report back.

SENATOR RADER: So we'll expect to hear from you perhaps Wednesday then on that item?

COMMISSIONER MARTIN: If we get the decision in a form that we can analyze I think we can do that, sir.

ATTORNEY GENERAL GROSS: Senator Rader, we do have Washington, D.C. counsel that are, of course, participating for us in the hearing, and I anticipate that they should have a report to us probably by tomorrow night as to at least a summary of what's happening, and we'll share it with the committee.

SENATOR RADER: You will share it?

ATTORNEY GENERAL GROSS: Yes.

SENATOR RADER: There were some other questions. Mr. Swanson, did you have a question?

REP. SWANSON: I never said a word.

SENATOR RADER: Anybody who has not? Senator Hohman and then Senator Sumner.

SENATOR HOHMAN: I was calling your attention to Senator Sumner.

SENATOR RADER: Senator Sumner.

SENATOR SUMNER: Mr. Chairman, I'd like to ask the Commissioner, I get the impression from Senator Croft that maybe Senator Croft is still under the impression that the State could have got a higher price for its gas. I'd really like to put that to rest. Do you think there is any real probability, under any circumstances, that reflect reality at all, that the State should have negotiated for a higher price in this contract or in other contracts?

COMMISSIONER MARTIN: Generally, no; but only if it had picked a completely different objective related to only price itself.

SENATOR SUMNER: Mr. Chairman, I'm not so concerned about picking a different objective if it's real. Is it real to expect that the State could have gotten more money?

COMMISSIONER MARTIN: I think it's, yes -- real isn't exactly it -- I think it would have been unlikely that we would have gotten more money.

SENATOR SUMNER: On a scale of one to ten, where would you say?

COMMISSIONER MARTIN: I couldn't give you that, I don't know.

SENATOR SUMNER: Well, it creates some serious doubts.

COMMISSIONER MARTIN: I would be pleased to do this, Senator Croft and Senator Sumner -- you know, I understand your question, and I'll look back at the transcript to get

the intent of it rather than trading back characterizations of one another's answers. I would be pleased to look at that and give you something at least indicating what I think the alternatives were for getting a higher price and the probabilities. Would that be acceptable to the Chair?

SENATOR RADER: It would be, although I'm sure the committee would like to share in that dialogue. Do you mean tomorrow, perhaps?

COMMISSIONER MARTIN: Tomorrow or Wednesday. I mean, we'll look at it and give you back an answer that's more definitive.

SENATOR RADER: Senator Croft, does that sound all right to you?

SENATOR CROFT: Maybe in the meantime you could tell me, as well, whether you initiated any contact with anybody that might have paid a higher price and asked them to bid as well.

COMMISSIONER MARTIN: No, I don't think that we did, because we weren't pursuing that as the principal objective.

SENATOR SUMNER: Mr. Chairman, let me continue for just one minute then.

SENATOR RADER: Senator Sumner.

SENATOR SUMNER: Do you think at this time it's worthwhile to postpone this contract in view of the merits of the

contract and what you're aware of at the present time that it can buy in the form of developing an expanded constituency for support in the South 48?

COMMISSIONER MARTIN: No, I don't.

SENATOR SUMNER: And on a scale of one to ten, how sure are you of that position regarding that? I'm really interested in knowing where your impact is.

COMMISSIONER MARTIN: I don't know where on a scale of one to ten, but I'm quite sure that that's right, I think, this objective as opposed to that one, is more important to pursue at the present time.

SENATOR SUMNER: Then would it follow that you believe that to the benefit of most Alaskans that the sale, that the contracts you've drawn here relating to the sales of royalty gas, is the best under most reasonable circumstances?

COMMISSIONER MARTIN: Yes.

SENATOR SUMNER: Thank you, Mr. Chairman.

SENATOR RADER: Senator Huber.

SENATOR HUBER: One short one to get in perspective again, one short little question came up. The class of people that we dealt with here, the three companies that we have sold to, are they, under FPC type language, are these the type of customers that are called common purchasers--the regulations that apply to common purchasers?

MR. BYRD: They're natural gas companies that are under the jurisdiction of the Federal Power Commission.

SENATOR HUBER: For instance, I am aware that all three of these companies do not sell any gas to anyone, they purchase the gas here and sell the gas to other gas companies that sell the gas, at exactly the same price they purchase it at, plus their transportation charges. Isn't that correct?

MR. BYRD: I don't know whether any of them are burner tip distributors or not.

SENATOR HUBER: The only thing I wanted to know so I can analyze it, are all three of these classed as common purchasers by the FPC?

MR. BYRD: I don't know what you mean by common purchasers. They're all natural gas companies under the regulation of the Federal Power Commission. They buy gas and transport it for resale.

SENATOR HUBER: Could you try to find the answer?

COMMISSIONER MARTIN: Could you say what you mean by common purchasers? What statutes would you reference?

SENATOR HUBER: FPC requires that pipeline companies be both common carriers and common purchasers. That's not true in oil pipelines but it is true in gas pipelines. I don't know about the next term, whether it's a correct one or not. Rather than analyzing it against

specific purchasers, maybe somebody who sells to customers in Northwest Michigan, for instance, and then in turn purchases from Tenneco or something.

MR. BYRD: I'm not familiar, Senator, with the terms "common purchaser" and "common carrier". There are natural gas companies and there are distribution companies. Distribution companies normally buy gas at the city gate from the natural gas companies, which these three companies are, and then they distribute it to the burner tip and sell it. They're under the jurisdiction of the State Commission. I don't know of any place in the Natural Gas Act where it refers to common purchasers or common carriers. They are not common carriers. They're natural gas companies and pipeline companies that are moving gas interstate for resale. They do move the gas interstate that's not for resale, it's sold directly to an end user, and they do do that. But that still doesn't make them common purchasers or common carriers.

SENATOR HUBER: So you can't list whether these three class as common purchasers or some other term?

MR. BYRD: As we use common purchasers in oil proration in the Lower 48, because you have to purchase commonly or equally from all the producers, but that doesn't apply to natural gas piplines. There's no use of the term "common carrier" or "common purchaser" in the Natural

Gas Act that I'm familiar with.

SENATOR RADER: Any further questions? Mr. Parr.

REP. McKINNON: I had a couple questions, Senator.

SENATOR RADER: Oh, excuse me, Mr. McKinnon, did you have a question?

REP. McKINNON: No.

SENATOR RADER: Mr. Parr.

REP. PARR: Going back to what we were talking about a while ago, other possible sales and so forth, who is buying the other seven-eighths, the producers' gas?

COMMISSIONER MARTIN: At the present time, Mr. Parr, I don't have the precise percentages. There is one contract which is valid, that's the Columbia contract we discussed at length the other night, which is approximately thirty percent. I'll be honest, I haven't been able to nail down the figure, but that's roughly accurate. And we believe that there's a small contract, and I can't recall, but it's less than one percent.

REP. PARR: Who is that?

COMMISSIONER MARTIN: Texas Eastern, we think. So far as we know, it's less than one percent. Those are the two that are still outstanding. The Columbia contract is the one we discussed at length at the hearing the other night.

REP. PARR: I realize, of course, that we're talking now about contracts which we know have been signed and are a

matter of public record and so forth. Do we have any information as to where this gas is going that is not a matter of public record, officially signed contracts, etc.? I would assume some of your high-powered experts would probably know.

COMMISSIONER MARTIN: Mr. Parr, I asked them -- in fact, after we had our conversation the other night in the committee, I attempted to find out. I wanted to know essentially if there was industry scuttlebutt or, you know, just information that was around that there were contracts. My best information, and it's limited by what is on the record, is that there are no others and there are no shadow contracts as far as I know that commit the gas, that people are waiting for the certification decision or for price information to firm up before those contracts are made. I've heard various rumors, but I know of no information with regard to other contracts.

REP. PARR: Mr. Chairman, I have just one other question.

SENATOR RADER: You still have the floor, Mr. Parr.

REP. PARR: Would it be your assumption that either one of the three companies that are involved in this is one of the three companies that is probably getting a good, large share of the producers' gas as well?

COMMISSIONER MARTIN: The company, our purchasers?

REP. PARR: These three.

COMMISSIONER MARTIN: No. In fact, my information is that none of them have made any commitments, informally or otherwise, any other contracts for any other part of it.

REP. PARR: Were there any of the other companies who were interested in getting our royalty gas whom we even know or have reason to assume were getting producer gas? Now, the only one you know for sure is Columbia. Did, for example, Columbia try to get in on the royalty gas deal as well?

COMMISSIONER MARTIN: No, they did not come to us. Northwest attempted to get into the royalty gas and, so far as I know, is attempting to buy producer gas, without success.

REP. PARR: I guess that leads up to my final question, Mr. Martin, and that is that I presume there were a lot of companies back in '75 that put up a lot of money and made all sorts of deals of lending money, and various other ways, in order to get this gas on the North Slope, and the FPC, I guess, or the courts, or somebody put the Kibash on this; right? These people were interested in getting large amounts and so forth. What is it that these companies such as Tenneco and Southern and El Paso actually have to gain by getting such minute amounts? I get the impression, or apparently at least as far as we know, that they have not tried to get the producer gas.

One would assume that ---

COMMISSIONER MARTIN: No, I didn't say that, Mr. Chairman. I thought you asked if they had it. I think they're all making substantial efforts to buy as much gas as they possibly can, as are a number of others.

REP. PARR: Is the amount of gas that is available from the royalty gas really significant? I mean, it's one-eighth less whatever we keep, right?

COMMISSIONER MARTIN: Representative Parr, again I'd just very briefly say, I think part of that is going to have to be judged by how important people think it is. I urge you to direct that question also to the producers and to the Delegation. They think it's important; three trillion cubic feet of gas, or whatever percentage they get, they believe it to be important, and I think it's a mistake to assume that that amount of gas is minuscule or unimportant. It is an important supply of gas, given the fact that we're talking about very limited gas supplies. The thing that holds this contract together, obviously, is that they believe that we will not be using great amounts of our royalty gas, and we believe that we will be using it all. Those beliefs are in conflict and we think that we have the ability to take it back if we want it. If they didn't have confidence they would get a substantial portion of it

they wouldn't invest their time and effort in the contract.

REP. PARR: Mr. Chairman.

SENATOR RADER: Certainly.

REP. PARR: I guess the thing that kind of bothers me is that in the initial commitments by the producers, at least the information I've seen, no one of these three companies was listed as getting it. There were a number of other companies listed. Now, these other companies would also have an interest in the route taken. Presumably, they were buying an awful lot more gas. I don't know how they compare in size to the three companies we're dealing with, but they must be pretty large, and presumably would have the money and the expertise for a lot of political clout. It just sort of disturbs me -- we keep acting as if this one-eighth is going to be the tail wagging the dog.

COMMISSIONER MARTIN: Mr. Parr, if I can suggest, there are some very important differences. For instance, we had a prolonged discussion the other night about the Columbia contract. There's quite a great difference between the Columbia commitment and ours. The fact, I think Mr. Gruening used the words, "Let's don't play the constituency game," -- well, we think it could conceivably be very important. The difference between the Columbia contract and this one is this: Columbia is going to get that gas

whatever way the route goes. They're going to get the gas whether it goes El Paso, or Alcan, or Arctic. In fact, they're on record with the FPC as saying that, that they think they'll get the gas just as well through any route. Our contract is different in that ours is the only contract, and may remain the only contract, where our buyers only get it if they back the successful route that's also backed by the State. So where we are different from them is that we have gained support in addition to simply committing our gas, generally speaking.

REP. PARR: Do you think the statement you just made about Columbia is true of the other major companies that were trying to buy the producer gas?

COMMISSIONER MARTIN: I would guess it would be, yes.

REP. PARR: In any event, it doesn't make any difference which route is chosen, they get the gas?

COMMISSIONER MARTIN: I don't know of any of those contracts that limit it.

REP. PARR: Thank you.

SENATOR RADER: Senator Croft and then Representative Chatterton.

SENATOR CROFT: I just want to pursue what Representative Parr was talking about. There is nothing that prohibits Tenneco from negotiating with the other owners of gas at Prudhoe Bay to purchase gas; is that right?

COMMISSIONER MARTIN: No.

SENATOR CROFT: And as far as you know, more than fifty percent of the gas at Prudhoe Bay is uncommitted?

COMMISSIONER MARTIN: That's accurate.

SENATOR CROFT: And for Tenneco to decide that it no longer wants to support the Alaska route, the only penalty under the contract is it doesn't get the Alaska gas. So, quite conceivably, since it's not prohibited from negotiating with other owners of gas, it could enter into an agreement, perfectly legal under the contract, with somebody that would furnish them more gas than the State, and the condition of that would be to support some other route in Congress.

COMMISSIONER MARTIN: That would be possible, but unlikely.

SENATOR CROFT: But it's not prohibited by the contract?

COMMISSIONER MARTIN: No.

SENATOR CROFT: Thank you.

SENATOR RADER: Mr. Chatterton.

REP. CHATTERTON: Thank you, Mr. Chairman. Commissioner, I've been told, rightly or wrongly, that some of the routes proposed need as an economic threshold a daily through-put on the magnitude of two billion to 2.4 billion cubic feet per day, and over probably a twenty-year period, in order to be economically viable. Is what I've been told roughly right, in your opinion?

COMMISSIONER MARTIN: That's right.

REP. CHATTERTON: At what point in time, Mr. Commissioner, are you willing to guarantee to anyone that is willing to build a transmission line that you will make available from the Prudhoe Bay pool 2.4 billion cubic feet a day of pipeline gas, available for them without jeopardizing ultimate recovery?

COMMISSIONER MARTIN: The point at which that could be guaranteed (if you want to stay with that word) is probably several years away, Mr. Chatterton. And I want to make it clear that that will be a guiding pivotal decision. That decision will be determined, as opposed to the decision with regard to the route. We intend to carry out the conservation statute of the State, and it's my feeling that the way it will go, roughly, is that an initial off-take rate will probably be approved based on a reservoir simulation study. A subsequent decision will be based on early field history, and decisions past that time will be based on the field performance to date.

REP. CHATTERTON: A follow-up question. Do you have any feeling whatsoever that any good business-minded company would commit funds for rolling of steel for pipelines, or for permits, or you name it, until they were completely assured of a study supply of gas and with no possibility, in other words, beyond all reasonable doubt, that they

would steadily have that supply of gas, it would not be cut off for conservation purposes?

COMMISSIONER MARTIN: If I can get myself there for just a second -- your question is just about as complicated and confusing as some of my answers, Representative Chatterton.

REP. CHATTERTON: I learned from you, Commissioner.

COMMISSIONER MARTIN: So, I'm willing to take the rap for that. Let me say this: I think that, you know, putting it your way, maybe no one would do it. But I think, as a practical matter, what is likely to happen is that a number of reservoir simulation studies and the early field history will be extremely indicative of the way in which that field is going to perform, and those who are interested, who are certificated and interested in building a pipeline, are going to have to make a hard decision in regard to the reliability of that information. But, my own opinion is they are not going to get a guarantee because no one can guarantee how a field will perform, and our conservation statute is rather clear in terms of which demands to make that field operate properly. So I think that there is a possibility, yes, the people will invest based on what they believe, based on sound information will be the deliverability figures through that route. As you may know, this was a point

of substantial controversy between the State and the Administrative Law Judge of the FPC, in which he demanded with, quite frankly, some anger that we guarantee him a figure. And I spent eight hours on the stand one day basically answering the questions for him that I just answered to you, saying that I couldn't and wouldn't give him a guarantee, at which point he concluded that we were obstructing the line because I wouldn't give him a once and for all figure.

REP. CHATTERTON: Thank you, Commissioner.

SENATOR RADER: Mr. Meekins.

REP. MEEKINS: Thank you, Mr. Chairman. I'm trying to approach this through the cost benefit analysis that Representative Gruening indicated, that we should look at it in terms of what we're giving up and what we're getting. I want to come back to the question about location of a petrochemical industry at tidewater. As I've been approaching this, it seems to me one of the benefits of a line reaching all the way to tidewater is to increase the competitiveness of petrochemcial products in Lower 48 markets and other markets because they wouldn't have to include in their costs the costs of overland transport and trans-shipment. So what I'm wondering is, does the contracts' prohibition against taking back the royalty gas and using it for an incentive

to locate reduce the possibility or the likelihood of a petrochemical industry locating in Alaska.

COMMISSIONER MARTIN: I really don't know if it reduces it or not. I think it limits our flexibility in regard to what we can offer, and maybe in that sense it does reduce it, Representative Meekins. How much is something I don't know. Let me say this: we've looked at that question seriously as we can in trying to consider various options before Royalty Board, and thus far at least there has been a pretty low level of confidence in the kind of deal where someone comes to you and says, "Let us export for blank-number of years, during which time we'll do a feasibility study or attempt to take some type of action, and at the end of that period if it looks good, build a refinery or a petrochemical plant." So I think it may well reduce the options, but it reduces one that thus far has not been particularly attractive.

REP. MEEKINS: Do you know if any of the companies that are in the contract that are getting the commitment of our royalty gas are also in the business of petrochemical products?

COMMISSIONER MARTIN: Yes, I'm certain there are subsidiaries of Tenneco. I prefer for them to answer themselves. There are probably subsidiaries in some cases.

REP. MEEKINS: Thank you.

SENATOR RADER: Any further questions?

REP. HAYES: I have one question, Mr. Chairman.

SENATOR RADER: Mr. Hayes.

REP. HAYES: Was the gas company mentioned that owns thirty to forty percent -- what's the name -- Columbia Gas? I've heard that they were so interested in getting that quantity of gas, or in tying it up from SOHIO that they went so far as to make a loan, an interest free loan of several hundred million dollars as an incentive, or whatever their purpose was. Anyway I understand it was tied in with the right to buy that gas, and my question is, when we were looking for purchasers for our royalty gas did we contact them and, if so, what was their reaction?

COMMISSIONER MARTIN: I can't say. I don't think we did contact Columbia Natural Gas, Mr. Hayes. They were unquestionably aware of the proceeding, and I made a number of public statements indicating that we wanted to hear proposals from anyone interested in engaging in this type of contract with a take back provision and supporting the Trans-Alaska route.

MR. BYRD: I might make one comment. There's been a lot of talk about the front end loan and interest free loans. You want to keep in mind that those are made to producers

for development and exploration, and I question whether or not they would ever be made to a royalty owner that doesn't really spend money for development of the acreage. All of them that I'm familiar with have gone to producers, and they have a commitment to develop, and then when the gas is developed the advancer has the priority to buy. I've never known of one to go to a royalty owner.

SENATOR HUBER: Mr. Chairman.

SENATOR RADER: Senator Huber.

SENATOR HUBER: Shouldn't that answer have been predicated also that this is maybe the only state that's able to take its gas in kind instead of otherwise?

MR. BYRD: Texas and New Mexico are taking theirs.

COMMISSIONER MARTIN: We're not the only state.

SENATOR HUBER: Well, we're virtually, aren't we?

COMMISSIONER MARTIN: Just a couple other little ones like Texas.

SENATOR HUBER: Like Texas? Is that relatively recent though?

MR. BYRD: They've had the right for several years but they haven't exercised it.

SENATOR HUBER: They haven't exercised it though, have they?

MR. BYRD: They are now, and so is New Mexico.

SENATOR HUBER: They're doing it now, but they haven't been up until very recently.

MR. BYRD: That's right.

SENATOR HUBER: Mr. Chairman, I was taken by the remark that a producer could expect this, but a royalty owner couldn't, especially under the condition that the royalty owner takes his gas in kind. If you will excuse me, sir, it appeared to me, the separation, to be completely ridiculous.

SENATOR RADER: Mr. Gruening.

REP. GRUENING: I just want a clarification of that last statement. Isn't the reason Columbia Gas would pay a cash bonus is to get a certain amount of gas committed, it could care less what the producer does with it. I mean, isn't the primary motivation of the gas company to get the gas, and that's why they pay the bonus?

MR. BONESS: Representative Gruening, after the discussion on Thursday night I attempted to find out additional information about the Columbia sale. The Columbia sale was entered into in 1971 ---

SENATOR RADER: Mr. Boness, would you speak up a little bit more?

MR. BONESS: The Columbia sale was initially entered into between SOHIO and Columbia in 1971. It involved actually six separate documents -- well, at that time it involved, I believe, four separate documents, two of which were amended in 1974. I don't have all of those documents, but those that I did have available I made available

to the committee's staff.

It's a very complicated arrangement, and the basic purpose of it was to make money available for development of the reservoirs and to insure that gas would be produced at some time. When it was entered into in 1971 the thought was the oil pipeline would be built at an early date and gas would be moving many years ago.

In '74 when it was realized that the gas wasn't going to move, some amendments were made to insure that the gas would eventually move. The purpose behind the advance payment orders, just in terms of the FPC policy, was to encourage exploration for gas. That's the reason (Mr. Byrd pointed out) it goes to producers and not royalty owners. Royalty owners don't explore for gas, producers do. It was to encourage the exploration of gas and a commitment to that gas to the interstate market. It was made at a time when oil companies were saying the reason they couldn't explore was they didn't have enough money to go out and explore.

Eventually, when the FPC reviewed that decision pursuant to a court order, it concluded that particularly with respect to Alaska the gas was going to be committed in the interstate market in any event and, therefore, advance payments with respect to Alaska were inappropriate.

In response to an earlier question by Senator

Croft, whether had the State entered into this advance payment, into this contract, we could have gotten front end money at an earlier time, the answer is only if we had entered it between 1973 -- there were two orders dealing with advance payment -- I believe August, but I'd have to check the month. There were two orders, and when the FPC issued its decision of December 31, 1976, it ordered a show cause order with respect to those that were entered into prior to 1973.

That included, I believe, four different companies, El Paso, Columbia, -- I'm afraid I can't mention the other two. Only the contractor Columbia dealt with North Slope gas. All of the advance payment contracts which had been entered into, and they had been for virtually all of the gas, were ordered to refund the money. So all of those contracts were refunded and, of course, the gas companies were not allowed to put in the rate base the terminated contract. The Columbia one, the show cause order was issued, they filed the response in March, and nothing has happened since then.

The Columbia contract, as a practical matter, could be terminated. Columbia has out, I believe, a Hundred and Seventy-Five Million Dollars in advance payments. Their net cash flow, I believe, is around a Hundred and Three Million Dollars, according to the

transcript, and obviously if a company has out a Hundred and Seventy-Five Million Dollars and can't put it in its rate base, it's going to be in a very difficult situation. Columbia witnesses testifying in the FPC proceeding testified that probably they would have to terminate the contract if they were ordered to refund the money.

REP. GRUENING: That question really went to the willingness of the gas company to pay it in order to get the gas. I can understand why the FPC wouldn't want it maybe paid if it weren't going to be used for exploration and development, but as far as the gas company went, their prime motive was to get the gas.

SENATOR HUBER: Mr. Chairman, may I get back with Fred?

SEANTOR RADER: Were you through, Mr. Gruening?

REP. GRUENING: Yes.

SENATOR RADER: Senator Huber.

SENATOR HUBER: Mr. Boness, right exactly where you left off, in the case of deregulation, which looks like it's imminent right now in Congress, or appears to be at least, wouldn't it be, if we approved these contracts, only our commitment with these three contractors that would prevent us from receiving a price that would allow us to recover proportionately what other people got in front end payments, by getting a higher price for our

royalty gas, because in effect others have got front end payments -- or did some of them, at least Columbia did. Wouldn't it be our contracts in case of the deregulation that would stand in the way of us doing that?

MR. BONESS: Do you mean the Columbia contract? That's the only one where advance payment happened.

SENATOR HUBER: No. For instance, right now Columbia has a contract that had front end, and apparently they'll get the highest field price that's allowed by the FPC to be paid for that. Isn't it true that for the State of Alaska to get that same higher price, including the front end money, our contracts will be standing in the way of that provided the gas is deregulated?

MR. BONESS: Let me start with the regulated situation. In the regulated situation there is a penalty that takes into account the fact that in the price, if everybody else was getting the highest price, Columbia would be paying something less because they'd already had some money.

In the deregulated situation it depends on what the contract between Columbia and SOHIO provides. I'm not completely familiar with that contract, but I suspect that Columbia will not be paying the same price for the gas it receives that some other pipeline company will be paying from somebody that had not advanced front end

money. In other words, I believe the Columbia contract more than likely takes into account the fact that, if degregulation occurs, some money has been paid already and, therefore -- say, Texas Eastern may be able to pay Arco a higher price than Columbia will be paying SOHIO.

SENATOR HUBER: You'd believe that we would be protected by this highest field price clause where they wouldn't be?

MR. BONESS: Yes, sir.

SENATOR HUBER: Thank you, Fred.

SENATOR RADER: Any further questions of these witnesses?

SENATOR CROFT: Mr. Chairman.

SENATOR RADER: Senator Croft.

SENATOR CROFT: So that I can get in context some of the questions that Representative Meekins has been asking, is it true -- and I guess maybe Mr. Byrd would be the one that might know this best, or Fred -- is it true that once the route is certified that there is going to be a tariff, in effect, approved for that basic facility? Whatever the plan that's submitted at that time, that's going to set that; is that basically correct?

MR. BONESS: Once the route is selected by the President and approved by the Congress, it will go back to the FPC and they will establish a tariff at that time.

SENATOR CROFT: Based on that particular facility?

MR. BONESS: That's right.

SENATOR CROFT: And any additions, changes, in that facility, any spurs off that facility, would then have to stand on their own weight in terms of economic viability; is that correct?

MR. BONESS: Well, any spur off the line would have to be certified first by the FPC in the new Section Seven proceeding.

SENATOR CROFT: And when you tried to certify that spur, would the FPC then go back and re-establish the tariff for the whole line with that spur as an addition, or would it keep the tariff on the existing line and set a new tariff for that spur?

MR. BONESS: I believe it would set a new tariff for the spur. The tariff sets a price for transportation between point "A" and point "B".

SENATOR CROFT: Right, and with regard to the El Paso line as it's proposed now, the tariff would be between Prudhoe Bay and Valdez, is that correct, and there would be intermediate tariffs for points in between?

MR. BONESS: Yes.

SENATOR CROFT: But there wouldn't be any other tariffs in Alaska established except along the route of that line?

MR. BONESS: There would also be a separate tariff for the LNG facility.

SENATOR CROFT: Right. But suppose somebody wanted to take a

portion of that to the Delta area, to Anchorage, or wherever, and you had to construct a small line in order to do that? The tariff for that small line would have to be such as to pay for that entire facility, is that correct, the entire spur?

MR. BONESS: That spur would be regulated by the State Pipeline Commission, not by the Federal Power Commission.

SENATOR CROFT: And it would have to be economically viable by itself; you wouldn't go back and get the FPC to come up with a new tariff for the Prudhoe Bay to Valdez line; is that correct?

MR. BYRD: It depends on where the sale was made. If the sale was made by the State to somebody at a point where the spur was going on, then that would be intrastate and the FPC would already have collected their proportionate share to get it there, and from the point of sale off the certificated FPC line to Anchorage, say, that would be a State regulated project and it would have to stand on its own feet.

SENATOR CROFT: So my question is, to what extent, in order to make sure that we have the maximum potential for developing and using the gas intrastate -- shouldn't we insist that any spurs be built into the basic line and, thus, reflected in the overall tariff to pay for that line rather than waiting until a later date and having

those spurs which then have to be economically justified by themselves alone?

MR. BYRD: I question if the FPC would certificate on this main line a facility solely for the movement of intrastate gas. The legislation that was passed prohibits them from preventing a take off and preventing the transportation through the facility to the point of take off, but I think from that point on it would be an intrastate project.

SENATOR CROFT: But suppose that we wanted to build a spur to Anchorage because, for some reason, it was more suitable to an LNG type of operation or to a petrochemical operation than Point Gravina is? Then that spur would have to stand on its own, would it not?

MR. BYRD: Yes.

SENATOR CROFT: But that if we built that in at this point, prior to certification if we insisted on the spur, it could be built in the overall tariff.

MR. BYRD: But the interstate shipper wouldn't pay any part of it.

SENATOR CROFT: Why not?

MR. BYRD: The FPC just wouldn't let them. The interstate shippers are only going to pay their proportionate share of the cost of the pipeline and whatever facilities are built that go on into interstate commerce.

SENATOR CROFT: Yes, and suppose you had a petrochemical complex that did send it on into interstate commerce at Anchorage so that it would be a part of interstate's interests?

MR. BYRD: You're thinking about a cryogenic plant at Anchorage that would move liquid gas on to the 48 States. I question whether the FPC or El Paso, either one, would. Under our contracts we couldn't do that, we couldn't take the gas out to liquefy it and move it to the 48 States. If we were going to use the gas in a petrochemical plant we could take it and move it to Anchorage or some other point, but we would pay the tariff from the North Slope to the point of the take off, and we'd pay the intrastate transportation, or our purchaser would, for moving it from the point off on the FPC certificated line over to Anchorage, and that spur wouldn't be FPC jurisdiction.

SENATOR CROFT: Was the question of any type of spurs to be constructed by El Paso considered during the negotiations? Were they requested to make any change with regard to their line?

COMMISSIONER MARTIN: Not during negotiations, Mr. Croft, but we have demanded on several occasions that they or other companies add spurs, or come forward with a proposal of spurs, for instance, in the case of Haines or some

other place, and they have refused steadfastly to do that.

SENATOR CROFT: As I understand it, they're going to be back Tuesday or Wednesday. I have some additional questions, the hour is getting late.

SENATOR RADER: Well, we can -- if it's in the nature of a general examination, then maybe we ought to pursue them the first thing in the morning. I do expect you to be back though probably -- first of all you said you would like to be able to sum up anything that might develop and secondly, you hope to report to us on the decision if it can be analyzed. What's your desire, Commissioner?

COMMISSIONER MARTIN: We're fine. We're in good shape until about Thursday of this week, Senator, and then we'll be sending -- I think Jack will have to return and Fred will be heading to Washington to work on the reply brief in the FPC, so Wednesday will be fine.

SENATOR RADER: Would you prefer that instead of tomorrow?

COMMISSIONER MARTIN: We'll be glad to come back and spend any amount of time. Tomorrow is also fine.

SENATOR RADER: Any other questions of these witnesses? If not, we will tentatively start out with Tenneco, Southern and El Paso tomorrow, hopefully at 11:00 o'clock, or as soon thereafter as the House and Senate adjourn.

(Whereupon the hearing adjourned at 5:00 p.m.)

SENATOR RADER: The Joint Committee Hearings of the House and Senate Royalty Gas Sale Committees will come to order. We invited Commissioner Martin and such other persons as he might deem appropriate to respond in any manner, that they see fit, to questions that have been raised that they think should be dealt with, or supplementary information. Particularly did we want to get from you an analysis of the opinion from the Trial Judge from your point of view as to what it says and what it doesn't say, and such other matters as you think may be pertinent to the committee.

I think the best thing would be for you and Mr. Boness, or either of you, directly to give us sort of a rundown on where you think we are and then start the questions, if that would be all right to do.

COMMISSIONER MARTIN: Yes, sir. Thank you, Senator Rader. I should say that after talking to you last week I've not come prepared to give you a full briefing and rundown on the FPC Judge's opinion. In fact, my understanding of last week was that once the thing was cancelled on Friday that we had moved beyond that, and the decision has been well distributed up here now. We can do that in rough form but, quite frankly, we didn't come prepared to do that; we came prepared to try

to respond to some of the questions that were raised and to take all your questions.

SENATOR RADER: I would appreciate your doing it just in rough form then as to your understanding generally, just for purposes of the committee. I know I haven't seen a copy of the decision, and I know that either you or Mr. Boness will have read it in full and analyzed it, and I would like to know what effect it has, if any, on these hearings, and on your position or on a position that we should take or might want to take.

COMMISSIONER MARTIN: Senator, let's take it on this way. I think we can say that Fred has read the opinion, at least largely. It's awfully long, and I have not gotten all the way through it. I have read certain parts of it, and I think we can give you a brief summary. Let's just start by having Fred run down some of the key points that are in the decision and then maybe we can talk about the meaning of them.

SENATOR RADER: Excuse me. I see Senator Kerttula. Senator, would you like to -- you're certainly welcome if you'd like to join us up here for the questioning.

SENATOR KERTTULA: Thank you, Senator Rader. If I have something I'll come up there. Thanks very much.

SENATOR RADER: Or you can stand and address the questions there, if you wish, from your seat. Yes, Mr. Nakak,

also. Would you care to join us?

MR. NAKAK: Not presently.

SENATOR RADER: Proceed, Commissioner.

COMMISSIONER MARTIN: I'll let Fred just give a brief run-down of the things.

MR. BONESS: I would like to start by indicating just a little bit about the procedure, what will happen now. The opinion, as you know, was issued on February 1. We have thirty days in which to file a brief of exceptions. Basically what that means is that the Judge throughout the opinion says, "I find Arctic Gas will be able to construct from snow roads in the time frame they've projected," and numerous other findings of that nature.

The State doesn't believe that that can be done. It will have a number of exceptions to findings of the Judge. We will have thirty days in which to file the brief, and the purpose of my going back to Washington, D.C. is to work with our attorneys back in Washington to prepare that brief, and all the other parties will be doing the same. Once that brief is filed, the Judge's decision, the whole record and those briefs will go to the Commission.

They will issue a decision, a recommendation to the President on May 1. The opinion itself is very long, it's four hundred and thirty pages with about another

seventy pages of appendices, some of which are also pertinent to the decision and must be read to understand the decision itself. It's organized into a number of sections, there's a Gas Supply Section, a Construction and Logistics Section, an Environmental Section, a Tariff Section, a Financing Section; and within each of those sections the Judge addresses generally what Arctic Gas says it can do, what he believes they can do, what El Paso says they can do, what he believes they can do. There is some discussion in each section of Alcan although, rather interestingly, the Judge at times just seems to ignore the Alcan proposal altogether. He never praises it, he occasionally criticizes it, but in general he just doesn't treat the Alcan proposal in anywhere near the same length as he treats the El Paso and Arctic Gas proposals.

I have not read all of the decision. I'm half way to three-quarters of the way through the decision. There are a number of places where the State of Alaska is mentioned in terms of the positions it has taken. We will have things to respond. As you may know or may have heard, the Judge asserts that the State is a person under the Natural Gas Act and that our sales will have to be certificated by the Federal Power Commission.

As I indicated on Thursday night to Representative

Gruening's committee a week ago, we are intervening in other cases -- we have intervened in other cases which address that issue and which may form the precedent for what would be the eventual finding in the Alaska proceeding. But, in any event, I would point out that the Judge's position is contrary to the position taken by the Office of General Counsel for the Federal Power Commission, and it will be a legal issue which will ultimately be resolved, I feel quite certain, by the courts.

I don't believe the Judge's assertion that jurisdiction exists is really in any particular fashion detrimental to the State's position. It is really based more on an assertion that it just must be so rather than on any serious legal analysis, in my opinion.

I believe I would prefer to leave it there rather than going into the number of specific issues that the Judge addresses unless it would be the committee's pleasure that I attempt to do that.

SENATOR RADER: Of course, the inquiry here is, should we or should we not pass the resolutions approving the sale. Is there anything in the decision from the point of view of the State that would impinge upon our decision as to one way or another in that regard, in your view -- or in your recommendation to us in that regard?

COMMISSIONER MARTIN: I would stick by the statement that we

made earlier, Mr. Chairman. This decision, once the procedural bill passed last year, is made less important than it would be under ordinary circumstances, and I'm not going to change that position because of the way the decision came out. On the other hand, the strength of the decision, it seems to me, points out two things very clearly. One is that the State has a tremendously long way to go to support either of the two routes that are in the State's interests; and the second thing it points out, and I want to mention this in the statement that I'm going to make to you today, is that this is a terrifically Federally oriented decision and points out, sort of in the most vivid terms, the kinds of things that we may be running up against in attempting to protect the future in-State use of our gas and running up against in terms of Federal jurisdiction over our gas.

So those two things very much, in my view, make what we're considering here more important -- in my view, make it substantially more important that we take action at an early time, and make it more important that we do what we can to support the El Paso route.

SENATOR RADER: I really didn't mean to open the questions at this stage. However, inasmuch as I have, do other members of the committee have any questions particularly concerning the decision, and then we would go into the

other. Senator Croft.

SENATOR CROFT: I do on that point. One of the reasons these contracts were announced on November 12 was so that they could become a part of the record, and both the staff report which was issued in December, and Judge Litt's decision which came out in February thus considered those contracts. What did the staff report and what did Judge Litt say about these contracts? What effect did the contracts have on their decisions?

COMMISSIONER MARTIN: I think they had pretty much the effect that I thought, and that was less effect on the FPC proceeding than they'll have on any subsequent proceeding. I stated that before publicly, and that was a point I made basically in trying to take additional time before they were introduced. I think that they didn't affect the decision a great deal, nor did I expect it to.

SENATOR CROFT: What did Judge Litt say about the contracts?

COMMISSIONER MARTIN: I don't recall that he treated them in length at all.

SENATOR RADER: Any further questions on the decision? Representative Parr.

REP. PARR: Mr. Martin, you used the term "Federally oriented" a minute ago. Do you mean that this was the same thing as what sometimes is called "In the National interest"?

COMMISSIONER MARTIN: Well, I don't know what sort of semantics

you're after, Mr. Parr.

REP. PARR: I'm not looking for semantics, Mr. Martin. You said "Federally oriented" and I don't understand the term.

COMMISSIONER MARTIN: Let me try to explain that. It seems to me that the best that the State of Alaska can hope to come out of this is with some agreed understanding between the Federal Government and the State with regard to the State's ability to use the royalty gas of their own. That understanding, in my view, would be to acknowledge that because of Alaska's production of these resources and distance from other markets, the needs we have in the State, that we will have a somewhat free hand to use our own resources.

At worst, on the other hand, the Federal Government will assert total jurisdiction over not just the gas that comes out of Prudhoe Bay, but the royalty gas that comes out of Prudhoe Bay, and direct that that gas be sent somewhere else other than Alaska.

Now, that's a whole spectrum of possibilities with respect to the gas that we own. When I say Federally oriented, in this context I'm referring to the fact that Judge Litt took the position that they should have virtually total control not over just the Prudhoe Bay gas but our State owned gas as well.

REP. PARR: In other words, what you're saying is Judge Litt said that the Federal Government would have the power then to decide where the gas would be most needed, including our royalty gas.

COMMISSIONER MARTIN: That's right.

REP. PARR: And then to send it there.

COMMISSIONER MARTIN: And went much further than that to advocate the repeal of Section 13-B and immediate assertion of Federal jurisdiction over our gas right from the wellhead.

REP. PARR: Thank you.

SENATOR RADER: Any other questions? Representative Gruening.

REP. GRUENING: Commissioner and Mr. Boness, is there anything in the decision that indicates why he thinks 13-B ought to be repealed?

COMMISSIONER MARTIN: Yes. He discusses it, not at length, but he basically makes the assertion that the Federal Government again should control all of the gas in the national interest rather than just the seven-eighths that belong to the producers, and really indicates that the Federal Gas Act, in his opinion, has applicability to all of it and that then all of the Federal powers given to the Federal Power Commission under its act would apply.

REP. GRUENING: You mentioned just earlier that the decision behooved us to move faster on these contracts. I think

that was your comment. What is there in the decision that compels us to do that?

COMMISSIONER MARTIN: Basically the fact that it pointed up the terribly uphill battle that the State faces in supporting either one of its two routes, and it seems to me that it just emphasizes the need for whatever additional assistance we can get from these contracts or the support that comes as a result of them.

REP. GRUENING: You recall that in the task force evaluation that there was mention of the fact that at some point the State would consider switching its support to Alcan, and now having been asked that question, and the decision hadn't come out yet -- now that it's out is there anything in that decision that would give the Administration cause to reflect and to change their position?

COMMISSIONER MARTIN: I think we'll continue to consider it, and we'll probably be discussing it this week, but my present reading of the situation is that the decision would not indicate a change is necessary.

REP. GRUENING: You will be discussing the possibility of switching support next week?

COMMISSIONER MARTIN: Yes, but I don't think that there is any strong possibility that we'll change.

REP. GRUENING: But that matter will come up?

COMMISSIONER MARTIN: I should say, that matter is under

just continual scrutiny and discussion because we want to make sure that whatever is in the State's best interests is protected. But I think it highly unlikely that we'd want to change because of this decision. In fact, our present directive is for Mr. Boness to go to Washington and prepare a brief opposing the recommendations made by Judge Litt.

SENATOR RADER: Any further questions on the decision? Representative Miles.

REP. MILES: Regarding Judge Litt's advocacy of repeal of the exemption, Commissioner, has anybody been in contact with our Congressional Delegation to gain a feel of how Congress feels since the Litt decision came down, and are you familiar with ---

COMMISSIONER MARTIN: Well, I've been in contact with the staff of our Delegation. I think I've been in contact with all of the staff since that time, not only on that question or precisely on that question. But I've discussed this issue, although not personally with any of the Delegation. What I'm learning from them is that it's really too early to assess what happened in Congress as a result of that decision. I don't think they've really digested it really anymore than we've been able to here. But they see the decision as damaging to the El Paso and Alcan case.

REP. MILES: But they don't have any strong feeling on the exemption either?

COMMISSIONER MARTIN: No.

SENATOR RADER: Senator Croft.

SENATOR CROFT: Could I -- just so we get it in perspective, the State had certain points that it wanted to make in the FPC hearing. One was support of the El Paso route, two was, I guess, some support of Alcan just so the State could keep that option open, three was to convince Judge Litt that we were not a person within the meaning of the Natural Gas Act and thus were not under the terms of it. Obviously, we didn't want him to come out for repeal of 13-B. Could you list the major objectives that the State had in its participation before the FPC? Just kind of run through it as to how we came out under his decision.

COMMISSIONER MARTIN: I don't think a list is necessary, Senator Croft. I'll just say that you listed at least the major ones, and there are a number of minor ones. My thought is that Judge Litt's decision went very much against the State's interests.

SENATOR CROFT: On all of the major points?

COMMISSIONER MARTIN: On the major points.

SENATOR CROFT: On the most of the minor ones too?

COMMISSIONER MARTIN: Yes.

MR. BONESS: Senator, I'd like to respond to that. What I believe you stated are really the ultimate objectives that the State's case took. But, in fact, there are a number of specific kinds of points which come up during the hearing; for example, the question of whether Arctic Gas would be able to construct its line from snow roads was debated at length. That's a much finer question. It goes to the State's objective because part of the reason the State opposes Arctic Gas is that it is going to involve substantial delays and substantial increases. The State put on considerable testimony on that point.

El Paso hired special consultants to put on considerable testimony on that point. Mr. Latts, who was the Federal Government pipeline person, put on testimony to the effect that it couldn't be done, and the Judge essentially rejected all of that testimony.

There are a number of other kinds of things like that, the question of whether adequate water would be available to manufacture snow if, indeed, they were going to use snow roads; the question of whether snow fences would be adequate. It really breaks down into a number of very specific kinds of things.

With respect to the El Paso proposal, questions with respect to the amount of gravel available and a number of things like that. And the Judge, in my opinion,

as far as his opinion that I've read, really accepted Arctic Gas' arguments in almost all cases and ignored the arguments of the State and others with experience in the gas pipeline construction here in Alaska.

COMMISSIONER MARTIN: I might just add to that, I think your question -- I don't think you assume this, but it may create the implication that it was sort of the State against these others. But the State was merely a part of a much larger presentation, whereas the bulk of the evidence was put on by El Paso, by Alcan, or some of the other parties who were intervenors to the case. Although we took a major role on most of these issues, we were not (let's say) the leading case.

SENATOR CROFT: On some of them we were the only people that were really interested in it, and that is particularly true with regard to whether the State is a person within the interpretation of the Natural Gas Act.

MR. BONESS: Senator, if I may respond to that one. The State filed a brief on that very early in the proceeding. No one filed a brief in opposition to that and, in fact, I believe you would not find that in the record at all except occasionally the Judge making a comment, "Well, whether the State is or isn't a person, will you tell us what you're going to do?"

The legal merits of that question were never

discussed or debated in the hearing at any point and, quite frankly, I'm a little bit surprised to find as much discussion of the issue in the Judge's opinion as there is. I think it was, if anything, a gratuitous effort on the part of the Judge to make sure that the State does not get powers beyond those which he believes we should have.

SENATOR CROFT: But in terms of that, in terms of 13-B, in terms of the regulation of rates within the State, which I think you, Commissioner Martin, made reference to Tuesday when we had the first summary of Judge Litt's decision, all of those points were basically points that it was not particularly an adversary situation, and yet he recommended against us on all of those as well; is that correct?

COMMISSIONER MARTIN: Exactly right, and that's exactly why I answered Mr. Parr's question that it was a very overtly Federally oriented decision. On the question of, let's say, rates he treated it very lightly in the decision in most cases, much more lightly than I thought he would given the fact I had been on the stand for eight hours on that issue one day. But, you're right, he took it on his own initiative to deal with those issues, as Fred says, gratuitously.

SENATOR RADER: Any further questions just on the decision?

Commissioner, why don't you go ahead and give us your general presentation?

COMMISSIONER MARTIN: Thank you, Senator. Last week, Mr. Chairman, the committee had comprehensive hearings on the gas line route issue and on the contracts, and as the opening witness for the State and the spokesman designated by the Governor, I took the approach basically of attempting to lay the contracts and the route preference decision before this committee, and to do so, at least in my own view, for my own part without heavy advocacy or really without a series of conclusionary statements. I, in fact, didn't make an opening statement. And I did that for several reasons that are somewhat important to me and I think to the proceedings.

One is, I think this issue is critical, and I believe it to be (like you) basically non-adversary and non-partisan.

Secondly, to a very large extent I served as not just the negotiator for the State, but the negotiator for the Legislature as well as the Executive on this matter, and I wanted the committee to have the best opportunity to understand factually what the contracts did as opposed to having to deal initially with a large number of the conclusions or implications that might spring from the contracts.

And I also wanted to hear, as a negotiator, very much what other people had to say about the contracts because no matter how substantial the level of care is, and it was substantial on these contracts, there is always a great deal more to be learned, particularly from the consultants and others that have an opportunity to examine these contracts in a clear, objective light. Basically I guess what I wanted to do was to see how well the contracts and the route preference stood on their own merits and to get an indication for my own part how well we did.

I've never said to this committee, and I'm not going to start saying today, that State decisions on this issue are clear-cut. Yet I heard a number of people say statements last week that were amazingly absolute, in my view. Virtually any course that we take, Senator, and I wouldn't want the committee to be mistaken about this, is going to have substantial trade-offs, it's going to have risks associated with it, and it's going to have both advantages and disadvantages. I think that although there are a number of people that really don't like to hear this kind of conclusion, I think that the differences between the alternative courses that are available to us are going to depend very much on subjective judgments made not just by myself or by the Governor, but by members

of this committee. Some things are going to be, and remain, difficult to quantify. I think they're going to have to be worked out subjectively by all of us working together. That's very true of these contracts.

Now, my opinion after seeing the hearings for a week, Senator, is that they were very useful. They were comprehensive, and on balance I think they developed some good information on very complex issues. There were a number of factual errors made, and we're going to try to be able to respond to those today. There were some very legitimate differences expressed with regard to State policy objectives that might be pursued. There were some wide ranging political judgments expressed. I think there was some good, expert consultation supplied to the committee.

We paid close attention to the hearings. We had them monitored throughout your consideration, and I think we come away with a pretty good idea of what it was we ought to do in future response to this committee.

I'm going to say some things in my statement today and I'm going to be prepared to respond to questions, and it may well be that we'll turn in additional written information at a later time if we feel that everything hasn't been covered.

It was a little hard to tell, looking at the

testimony last week, what the most shocking piece of testimony was. It was probably a toss-up between Arlon Tussing telling us that the entire State and its leadership have been tricked into believing that we have any role in this decision at all; it could have been Mr. Dallas telling us we made a big mistake by not coercing a gasoline plant in Fairbanks as a part of these contracts; or it might have been that the buyers couldn't assign a dollar for dollar value to what it was they proposed to do.

But let me say that, at least from my personal judgment, the most shocking piece of evidence before the committee last week was probably Judge Litt's decision. It was something that didn't happen here at all. In the terms of the sort of significance that we have to deal with in these hearings, it seemed to me that, as I said earlier in response to Mr. Croft's question -- it seems to me that we learned from that decision a great deal more about the uphill battle we have to face and a good deal more about the sorts of Federal orientation that we're likely to meet as this issue is developed in Congress.

What I'd like to do today, Mr. Chairman, is to continue in the role of elaborating on the contract factually and to respond to your questions. But I'd also

like to do one other thing that I feel somewhat compelled to do in the role that I've tried to fulfill for the State, and that is to try to add at least some perspective to the issue based on my own judgment and on my experience as a negotiator for this contract and on my experience in dealing with this issue on behalf of the State in the Federal context. I've spent time on this issue, both for this Administration and for the last one, and think that the committee probably can benefit from at least what some of my judgments, again admitting that they're only subjective, with some of the others that have been made, to add my words to theirs.

In other words, I feel that after hearing a great deal of useful testimony last week, I think that it will be useful for me to at least give you the benefit of my advice as well as the information I can supply. First, I want to make it clear that I believe after hearing everything, and you always hear these things with a certain amount of trepidation as a person who negotiates it, particularly in the context of our statute, I want to share with you my belief that both the contract and the route preference held up remarkably well during the course of the hearings last week. No witness, with the exception of those who favor another route, such as Mr. Ward, Mr. Thompson or Mr. Tussing, made any substantial

allegation that the best route for Alaska was anything but the Trans-Alaska route.

In addition to that, the clear-cut consensus of the consulting experts hired by the Legislature was that these are good contracts achieving some objectives now which may not be reasonably expected to be surpassed or even equalled later. Third, on taking into account all that was discussed last week, I believe that no questions have been raised which cannot be reasonably answered and none that persuaded me on balance that these contracts do not best achieve a series of crucially important objectives for the State.

Now, beneath all of the specifics which have been raised is the overall issue raised best by Mr. Gruening, "What do we get and what do we give up?" Slightly below that is a similar question, and I think it went unspoken in many cases last week, "Can't we do better in the future if we just wait now?" The answers to those questions are complex and they depend on many variables, and rather than cite them all, let me give you an example of what I mean.

To the question, "What do we get," the variable is, "What do we want?" And I think that what we want is something that people have not been clear in addressing beyond the words and the implications that were created

by public opinion and legislative actions and administrative actions since last year.

What do we want? It might be price, it might be in-State use in the future, it might be the route that's best for Alaska, it might be a lump sum payment, it might be total future flexibility with regard to this gas for the next three or four years. But in any case, at some point what we want has to be defined rather clearly. In my view it was defined rather clearly at the time we led up to these contracts, and we ought to establish that ground again.

To the question, what do we want, my own fear is that one of the things that comes out of the hearings last week is that the answer of too many people is "everything." I just want to make it clear, both as an advisor and a negotiator, I don't think we can expect to get everything, and perhaps we didn't in these contracts. But I don't think we can answer that question by saying, "Everything."

Over all, and I want to make this very clear because I believe the hearings narrowed in many cases to an investigation of specific values, pro or con, that were inherent in the contract. Let me make clear what my own feeling as your advisor is on this matter. Over all, what I believe we got in the contracts is a

balanced package of terms on key objectives for the State. In my view the objectives are right, the terms are solid, and there exists real risk that such a package cannot come together in the future in exactly this way. That may not mean, in your own mind, that you should do it. But I want you to be clear that my feeling is that that's my conclusion, and it will be difficult to put this kind of package together again in this way.

I believe that many of the statements that were made last week missed the balanced nature of these contracts, and I believe they missed the present opportunity they represent, and I believe that there was a certain misconception with regard to what we can absolutely rely on to be accomplished in the future.

What you get, in other words, is an approach with many facets and many aspects to it, which is available now, and one which provides a whole series of terms giving protections for the State which may or may not be available later, but achieving this combination at a later time, if it does represent desirable alternatives and desirable objectives, may not be a dependable assumption.

I do not propose to speak to you in absolute terms as some did last week because I don't think this is an absolute issue. I am going to lay out, however,

some of the benefits and risks as I see them, and to give you the opportunity to work with me to try to balance those risks and benefits, to look at these contracts as a unit rather than in looking at them, as we did last week in so many instances, as a series of specific issues, all of which can be considered, I think according to the assumption that we can achieve the same combination again or whether we can't achieve it again.

First, in these contracts the State gets a reasonable approach, in my view, to a decision on this entire issue, and it gets it within the formidable constraints of our royalty process. Now, our statute is wise in the public interest, and I've said so before; but it's cumbersome and it's politically charged. It's a one-year cycle or perhaps somewhat less in which the Administration, the Commissioner of Natural Resources and others must either guess or ascertain what the public will and the legislative will is with regard to royalty oil or gas, then must work through the businesslike task of negotiating an entire contract to deal with these issues, and then must go through two levels of review, which can be extremely time consuming, during which time the circumstances that favor or disfavor any deals so made can change.

The present contracts, in my opinion, have done

very well in this process, and they're based on a reasonably identifiable public and legislative will. In other words, we started with a reasonably good idea of what was desired and we went through at least a very large percentage of the complicated and cumbersome nature of our process in fairly good form, and we're still proceeding in that, in my view. Now, how well this process works in the future is going to have a great deal with how well it works in this instance and how well all of us work with the process, and that has nothing to do with whether the contracts are approved or not. It has to do with the way in which we deal with them.

To reject these contracts now, particularly without a good understandable, specific basis of guidance as to where we go next, leaves us with a process which is neither rapid nor flexible, our royalty process, and perhaps without clear direction, and still facing the same problems which we believe were answered very successfully in this contract. So I think that there's an inherent risk in starting over again without clear guidance. If we have the clear guidance and we have the time, then it may well be a different case. But I think that we have an alternative now that it's going to be difficult to duplicate given the nature of the

process. I think it's a risk of rejection you should clearly face; that is, very simply, the risk of putting together a deal in this form and of this nature again.

Second, in these contracts we did get the best price for royalty gas sold under any reasonably foreseeable circumstances. I say that after listening to testimony last week, hearing your consultants deal with it very thoroughly. Quite frankly, after the strong testimony that your own consultants gave, I'm hopeful that this issue is put largely to rest. If it is not, simply let me say that I believe that it should be, and that the State can say with some certainty that it did get the best price that it can reasonably expect to get under any foreseeable circumstances.

For you to reject these contracts on this basis, you must conclude that it is not only technically possible to get a better price later, but that it is probable or even possible that we can better or even equal what is presently available to us.

For the record, my advice to you is that it is not a risk worth taking, and it's not a possibility that you can or should rely on, and not something you can assure the people of the State is capable of accomplishment. Remember that under these contracts we tie the price the State gets for its gas to the best

price coming from the Prudhoe Bay oil field, oil and gas field, so that if only one buyer gets a terrific deal on his gas we're tied to that price. So we have the benefit of virtually every other good negotiation for gas from that field.

Third, there is the issue of in-State use. What we get, again in a balanced package, is a negotiated term in this contract that allows us to sell our gas but not really to sell it, to take back virtually every cubic foot of gas that we can use for Alaska's future. So far as I am aware, this term is without precedent in gas purchase history. The driving force for the term, in my view, is uncertainty; uncertainty about what we will ever use, which allows both the buyer and the seller to make of it what they wish.

To reject this contract, you must accept the risk that this total take-back term can be equalled or surpassed later. I do not know how, quite frankly, it can be surpassed. And as your negotiator, I can advise you that I believe there are substantial risks to be acknowledged if you were to act in the belief that such a term can simply be renegotiated equally. I think there are a number of reasons that indicate that it will be quite difficult to establish such a term again.

Fourth, there is the protection of the take-back

provision itself. What we get, in my view, is the best foreseeable opportunity that Alaska will have to protect its ability to use gas in the State. We not only have negotiated the best possible take-back provision, simply the right to take back all of the gas, but we are able to advance it for Federal approval at probably the most advantageous time foreseeable for doing so..

To reject the contract now, I believe that you must accept the risk that Section 13-B will remain unchallenged and on the books and that at some later time you will be not only able to negotiate the same kick-back term, but that we will have the same or better chance to get it approved at the Federal level. My opinion, and again I'm acting in an advisory capacity here, is that our best chance to avoid that risk is by acting now.

And fifth, there is just the question of the route itself. On the one hand we had Arlon Tussing, a good friend on whom I've shared many opinions on this issue, who basically indicated that we should fold our tents and wait quietly for the end on the gas line issue. On the other hand, we have the Congressional Delegation and the Governor stating in no uncertain terms, as I see it, that the State does have a definite role in this gas line proceeding and that these contracts are important

to the outcome, that the combination of buyers is right, and that the decision should be made as reasonably quickly as possible.

For my own part, again giving you the benefit of my feeling about this, I certainly want to come down on the side of saying I think we do have a role in this, and I say it from the perspective of participating both in the Native Land Claims and Trans-Alaska Pipeline decisions in Washington. I think it's simply fallacious to assume the State has no role whatever and that we should simply accept what comes our way. Again, I would reiterate that what I say about the route is totally separate from all the other points about the protections that we may be able to gain from these contracts.

To reject these contracts, in my view, you have to be willing to accept the risk that the additional help afforded by the buyers either won't be any help at all or that it won't help enough, and accept the fact that no matter what your individual reasons, your action in rejecting these contracts is going to be perceived broadly as a rejection of the Trans-Alaska route. For my own part, given the fact that the contracts will be void if we lose, given the fact that they are clearly of extreme importance to our Congressional Delegation, given the fact that they will be void if

the full take-back scheme is not approved Federally, given the fact that we will be doing all we can to develop the in-State uses which could conceivably mean that we never really sell a cubic foot of gas, that is, get something for nothing; given those facts, I don't think the risk of rejecting the additional assistance makes a great deal of sense.

In conclusion, I would say that after a full week of testimony a number of specific points have been raised, but no one has yet suggested a concrete comprehensive alternative to the kind of advantages that are suggested by these contracts.

Now, I'm going to be pleased to answer your questions, but I hope that that additional subjective judgment helps you at least to understand what I think is important about the contracts.

Thank you, Mr. Chairman.

SENATOR RADER: Senator Huber.

SENATOR HUBER: Thank you, Mr. Chairman. Commissioner Martin, would you care to comment on whether the course that we embark upon with these contracts is anywhere as near strong enough to win the route decision, especially in light of Judge Litt's decision? Might not we be relying on too little too late? Might not the contracts' greatest drawbacks be that they stand in the way of an all-out

effort, such as that outlined by Jess Barry of Anchorage when he talked to us Friday?

COMMISSIONER MARTIN: I'm sorry that I didn't read that statement, but it seems to me that you're going to get the maximum amount of effort that we can expect to see from these contracts as they're presently framed. In my view that would be my position, Senator Huber, and it seems to me that we can always say that we're later than we would like to be. Had not legislative approval been necessary, had it not been as difficult as it was to negotiate what I think are good contracts, we may very well have been able to go earlier. But it seems to me that we have an opportunity to do the right thing now.

SENATOR HUBER: You're not familiar with Jess Barry's proposal that he made before us Friday then?

COMMISSIONER MARTIN: Is it the proposal to eliminate the flexibility provision in the contract?

SENATOR HUBER: No. It's a total proposal to get behind it much harder. He likened it onto the way Alaska got behind the Tennessee Plan to become a State, and he meant getting with El Paso and joining with them, using the State's bonding ability and everything else to help in building the line so that we had something really to sell to the people of the Lower 48, that Alaska is

getting in there to get them the energy they need.

COMMISSIONER MARTIN: I'd say two things, Senator. I haven't read the proposal in detail. I'd be glad to do it. I think that there will probably be things that we should consider that would be of even more assistance. But if I understand what you're saying, nothing that he proposes in any way conflicts with the value or the benefits of engaging in this contract.

SENATOR HUBER: That part may be true. Thank you.

SENATOR RADER: Representative Hayes.

REP. HAYES: Mr. Martin, on Friday Mr. Moody, who was retained by this group, testified regarding one provision in the contract which has been discussed as being one of the major pluses, and that was the take-back provision. He indicated that the contract was so strong in favor of the State, particularly in that respect, that when the producer/owners get around to financing the project they may very well be faced with the problem, in dealing with the financial institutions, of coming back to the State and asking for some subordination or some relief relating to that particular paragraph of the contract. Have you taken that into consideration, or do you have any opinion on it as far as ---

COMMISSIONER MARTIN: I've heard that point, Representative Hayes, and, of course, it came up in negotiations as the

buyers attempted to tell us that we may, indeed, be driving too hard a bargain. But it seems to me that that again does not supply a reason to vote against the contract, but only a fact that we may have to acknowledge in the future. My own view is that he over-stated the possibility of that happening. But, in any sense, I think we ought to acknowledge it; but it doesn't give me any pause at all in going ahead with the contracts.

REP. HAYES I think he made a statement to deal with the alternative, which would not be entering into any contract, and by not entering into any contract you would not be put into the position of having to commit your royalty gas. But then I think he, on the other hand, said that if the State doesn't have their act together by that time, by the time the pipeline is built, that we may very well lose it anyway, the FPC may take it. Do you agree with that?

COMMISSIONER MARTIN: That's the point I guess I was getting at, and I would say this: a number of factors are going to have to develop. Certification is the first of several. Beyond certification, for which financing will be a part, there will actually be the putting together of a package to build whatever pipeline is certificated. I think the State gives up nothing by going with these contracts now that it can't adjust to and have a reasonable

opportunity to adjust to at a later time.

REP. HAYES: Thank you.

SENATOR RADER: Representative Gruening.

REP. GRUENING: Commissioner, can we infer from what you've said that the Administration would not take kindly to any suggestions of amendment to this contract? Do you see any -- in other words, let me just say the consultants did suggest some areas where the contracts weren't perfect and there were some areas where we could lose something in terms of price.

COMMISSIONER MARTIN: So far as I'm aware, Mr. Gruening, none of the consultants suggested amendment. They suggested in many cases clarifications which they felt would be useful, and we'll attempt to supply those. Our position on amending the contract is that if it's in the public interest to do so, we're not totally closed to the possibility. The Legislature should be advised that amendments are a rejection of the present contracts. Our procedure doesn't provide for amendments, but merely approval or disapproval by the Legislature. We'll take into consideration the reasons, if they're stated in a unified manner, that a rejection is undertaken and attempt to renegotiate the contract if it seems desirable to do so. At the present time, frankly, we have not yet had pointed out to us in any unified way suggestions for

amendments of the contract which would cause us to believe they ought to be amended. I'm not saying we're closed to it, but I'm saying it has implications for timing and it has implications for future decisions on this which we'll just have to discuss.

REP. GRUENING: Have you considered a special bill to allow an expedited procedure for amendment?

COMMISSIONER MARTIN: I've given it some thought and I'm not unwilling to discuss it. But as I've said before, the way in which the Legislature deals with these contracts is going to have a great deal to do with what happens in the future in the royalty process. I think you are well familiar with my view, that that's going to have to be done in a way that doesn't create the impression of the Legislature renegotiating the contracts. I think that if you do that you'll simply find that future individuals occupying my office are not going to be willing to put anything on the line in negotiations.

REP. GRUENING: I'd like to call your attention to the statutory provisions I think that govern you and the Royalty Board, and I don't know if you were here but you probably had an observer when Red Boucher made his comments on a finding of surplus and immediate, domestic--along with domestic and industrial needs for the royalty gas. He stated that he was aware of no study that had been

submitted in accordance with the statute; in other words, a report showing an immediate and long-range domestic and industrial needs of the State for royalty gas. Is that a correct assessment, or what reports or report have been submitted in accordance with the statute?

COMMISSIONER MARTIN: There are really two answers to that question. First, I don't believe it's a correct statement. Two items have been submitted to the Legislature to fulfill that requirement. The first is this analysis, which is included in all the legislative packets. I understood that it got left out of a few, but eighty came over to the Legislature. The second was, this document here, which wasn't in all the packets but which was given to the Chairmen, at least to Senator Rader, which is the background document for this. And this document, Mr. Chairman, is a lengthy bibliography which indicates the nature of all backup information dealing with surplus gas.

Now, these things do exactly what the statute demands, and that is to analyze the present and future demands for surplus royalty gas. I'll go one step further than that. The Legislature has a question before it. I think we could spend a good deal of time deciding whether or not this is exactly what you had in mind for your report. In my mind it's unquestionable that this

deals with what we have, what the future may bring, and what kind of surplus we have. So it's a technical decision for the Legislature, which gives you every ability to deal with the issue of future surplus. I should also say that the Legislature received a copy of the Royalty Board minutes and the indications of the Royalty Board's consideration of this in which this was also well discussed, and all of these documents referenced.

But as a further point, let me just say that that point as a technical objection is exactly the kind of thing that the Legislature should avoid to use as an escape hatch for this kind of decision. The plain and simple fact of the matter is that these contracts take care of the surplus provision by definition. There is no question that the future uses of royalty gas in these contracts are protected by the terms of the contract itself. Any future use -- and those future uses are unknown -- is protected by the terms of the contract. So that the analysis itself, while it's interesting and fulfills the terms of the statutes, is really not necessary to appreciate the fact that we don't sell any future gas that's not surplus.

REP. GRUENING: Mr. Martin, I don't think it was the intention of that question or any of the Legislators here in raising that, to find an escape. I think we're looking

to see whether you and the Board have complied with the law.

COMMISSIONER MARTIN: I understand.

REP. GRUENING: We have to examine, you know, it's our role to examine that.

COMMISSIONER MARTIN: I understand, and I wasn't suggesting that. I'm saying that -- I wasn't suggesting that motive. I was suggesting that I think that it's not an appropriate one, either in terms of being fulfilled or in reading the contract fairly. I might say that I've asked Mr. Boness, as well, to look at the material that was submitted and to consider whether or not he thinks it's reasonable in terms of fulfilling the law, that the procedure might not have been fulfilled, and I'd ask him to talk to that.

REP. GRUENING: No, let me just mention, you stated that the take-back provisions in the contract -- the inference was that that made the subject irrelevant as far as surplus ---

COMMISSIONER MARTIN: No, I didn't say irrelevant.

REP. GRUENING: The inference was that the take-back provisions had something to do with the compliance with the statute, and it's just my reading that whether or not there are take-back provisions in the contract wouldn't have any effect on whether we find, in fact,

that you complied with the need to find a surplus.

COMMISSIONER MARTIN: I'm in agreement with you on that. I didn't mean to suggest that they avoid the need for fulfilling the requirement. I don't think they do. But I think, to a large extent, the relationship between those two ought to be understood in terms of the objective of the statute, which is to protect us from contracting away anything that is not surplus.

REP. GRUENING: These two reports, these are the documents in which you place your reliance for compliance with the statute?

COMMISSIONER MARTIN: That's right.

MR. BONESS: Representative Gruening ---

SENATOR CROFT: Could I ask?

SENATOR RADER: Senator Croft.

SENATOR CROFT: That particular statute, 38.05.184(d), that's what we're referring to; right?

It says, "The Commissioner shall make public, in writing, the specific findings and reasons on which his determination is based and shall, within 10 days of the convening of a regular session ..." -- I must have missed that in my copy. Did you, yourself, Commissioner, make specific findings?

MR. BONESS: Senator Croft, that refers to specific findings in writing, I believe, for waiving of the competitive

bid provision; is that not correct?

SENATOR CROFT: That's not correct. "...within 10 days of the convening of a regular session of the legislature, submit a report showing the immediate and long-range domestic and industrial needs of the state for oil and gas and an analysis of how these needs are to be met."

MR. BONESS: That's right, that's the statute.

SENATOR CROFT: My question is, where are the specific findings by the Commissioner?

MR. BONESS: These documents.

SENATOR CROFT: I thought those were done by the staff.

COMMISSIONER MARTIN: They were submitted as a part of the information submitted from my office to the Legislature, and by the Governor.

MR. BONESS: Senator Croft, you're not suggesting that the Commissioner, himself, personally has to perform the economic analysis, are you?

SENATOR CROFT: Yes. It seems to me that the Supreme Court in the Kachemak Bay decision would probably read that statute the same way.

MR. BONESS: Well, I would not recommend that. If you look at the ---

SENATOR CROFT: That was the argument the State was making in the Kachemak Bay case, wasn't it, that the Director of the Division of Lands didn't actually have to do it?

MR. BONESS: Senator, I'd prefer not to debate that point. I would point out that almost all of the statutes dealing with the responsibilities of the Department of Natural Resources refer only to two persons, the Commissioner of Natural Resources and the Director of the Division of Lands. As a legal matter, I would not render an opinion that said that those two individuals had to perform all of the tasks now being performed by however many people are employed in that agency.

SENATOR CROFT: But isn't that the question we're talking about with regard to whether 38.05.184(d) has been complied with?

MR. BONESS: Yes, it is, and I believe these documents do comply with that.

SENATOR CROFT: Then you are rendering a legal opinion that that statute has been complied with?

MR. BONESS: That's right.

SENATOR RADER: Any further questions?

SENATOR CROFT: I had some additional questions. Commissioner, with regard to your statement that, "We have gotten the best price we could reasonably expect to get under the circumstances," one of the things that Mr. Moody said was that we are conceding by these contracts that the State sale price is limited to the amount which the Commission will permit the buyers to retain in their

jurisdictional rates. Do you mean by saying that we've got the best price reasonably possible that we had no chance of making the argument before the FPC and won't be able to make the argument successfully before the FPC that we are not a person within the meaning of the Natural Gas Act?

MR. BONESS: No, Senator, it does not mean that at all.

SENATOR CROFT: Are we going to concede the point before the FPC that we are a person?

MR. BONESS: No, we are not. We definitely are not going to concede that point.

SENATOR CROFT: Do you think we have a reasonable chance of prevailing on that?

MR. BONESS: Yes, I do.

SENATOR CROFT: And if we do prevail on that point then our rates are not limited by the FPC?

MR. BONESS: No, I can't agree with that.

SENATOR CROFT: Isn't that what Mr. Moody said?

MR. BONESS: No. Let me tell you what I believe Mr. Moody had in mind. Mr. Moody and Mr. Swanson both addressed the question to the effect that the State might argue in the rate setting proceeding which will occur sometime in the future before the Federal Power Commission, that the State might have a special argument to the effect

that royalty gas should receive a higher price than working interest gas because the State is a state, and the money received by the State will go to public purposes. I'm afraid I don't recall what Mr. Swanson and Mr. Moody's assessment of that is. I believe their assessment was that that's pretty unlikely, although I'm afraid I don't know whether they told the committee that or I just recollect that from conversations with them. But I am willing to state that it's my opinion that that outcome is extremely unlikely, and there are two reasons for it. First of all, in effect, what you're doing is, you're saying that the working interest owners have put money in at risk and have incurred certain costs, they should receive a price less than the State, where the State hasn't incurred any costs, hasn't put any money at risk in terms of the development or exploration of the field, and yet should receive a higher price simply because it's going to put its money to a public purpose presumably, and the oil companies are not.

Furthermore, when you analyze that through, what you're really saying is the purchasers of gas are going to be paying a higher price for that gas which is sold by the State of Alaska. I think when you carry that argument through, what you're really saying is consumers

in New York and in the East are transferring money to the treasury of the State of Alaska, and I think when the argument is cast in those terms it's unlikely to be persuasive at the Federal Power Commission. There is no obligation on the Federal Power Commission to so find that State owned royalty gas should receive a higher price, and I just personally do not believe that there are many compelling arguments that can be made to cause the FPC to associate a higher price with respect to State royalty gas than other gas.

SENATOR CROFT: I had thought that the position of the State, Mr. Chairman, was that sales of royalty gas are not to be regulated by the Federal Power Commission.

MR. BONESS: That's right.

SENATOR CROFT: And that was what Mr. Moody was also suggesting.

MR. BONESS: That's right.

SENATOR CROFT: And if they're not regulated, then a price higher than what they allow could be obtained?

MR. BONESS: Only if you can find somebody to pay it.

SENATOR CROFT: That's correct, and what you're saying is you think that there may well be -- we may well win with regard to this point before the Federal Power Commission if we don't execute these contracts, but that we can't find anybody to pay the higher price?

MR. BONESS: I think that's a part of the problem.

SENATOR CROFT: And who did we negotiate with to determine if they would pay a higher price?

COMMISSIONER MARTIN: We didn't negotiate with anybody, Senator Croft, but we've solicited nation-wide two times to attempt to find buyers who would come and negotiate with us on those or any other terms to provide for in-State use or for other purchases of our gas, and we haven't found people who will do it. So the answer is, we didn't negotiate with anybody, but we didn't find anybody to negotiate with.

MR. BONESS: I would go beyond that, Senator. We still confront another legal problem, and Mr. Moody did concur on this, and that is the problem of sales to people who are not regulated by the Federal Power Commission and whom you seem to be suggesting might be willing to pay a higher price.

SENATOR CROFT: No, no. What I'm talking about is because this sale is not regulated. That's the State's position, isn't it?

MR. BONESS: That's correct.

SENATOR CROFT: Do you agree with Mr. Moody that we are now conceding that the FPC does regulate the price?

MR. BONESS: No, I certainly do not. In fact, Mr. Byrd pointed out that the contracts were drafted to make sure that there was no argument available to the Federal

Power Commission that the State was placing itself in a position identical to that of the producer. We tie ourselves to the price the pipeline companies are allowed to include in their jurisdictional rate base. We do not, although as a matter of convenience it's easy to think of us as tying ourselves to the producers, and indeed in many ways we do, as a legal matter I believe we protected ourselves from an argument that these contracts constitute an admission that we're subject to the Federal Power Commission's jurisdiction because of the way it's drafted.

SENATOR CROFT: So that you disagree with his statement that we are conceding the point of FPC regulation?

MR. BONESS: Senator, I never understood Mr. Moody to say that we were conceding we were subject to jurisdiction. I understood him to say that we would find ourselves being indirectly regulated by the Federal Power Commission with respect to price. I agree with that, I believe it's inescapable for us. But if you're talking about a technical, legal matter, I do not believe we have conceded it.

SENATOR CROFT: We've conceded that the only price that these buyers can pay is what can be built into their rate base?

MR. BONESS: That's correct.

SENATOR CROFT: And so that we have, in effect, given any authority that we have to try and determine a rate.

MR. BONESS: That's correct.

SENATOR CROFT: And you'd agree with his point on that?

MR. BONESS: Yes, I do.

SENATOR CROFT: That whatever authority we had to try and get the highest rate with regard to future sales is given up and our sole rate determination is based upon what third parties agree to?

MR. BONESS: The rate will be determined by outside parties, yes.

SENATOR CROFT: Do you also agree with his point that there is no price at this time and that if the status quo remains that you will have to go back and renegotiate these contracts in order to get a price?

MR. BONESS: No. If the status quo remains, there will be no gas produced in Prudhoe Bay. The producers haven't entered into contracts.

SENATOR CROFT: If the status quo with regard to no deregulation, his point in item number three ---

MR. BONESS: If gas continues to be regulated the price that Prudhoe Bay gas may be sold in interstate commerce for resale will be set by the Federal Power Commission. It will not be necessary to renegotiate the contracts. We will accept the price that the pipeline companies are

allowed to include in their jurisdictional rate base. That price will be determined by the Federal Power Commission. I believe what Mr. Moody said was the State ought to be prepared to participate in that rate setting proceeding.

SENATOR CROFT: Maybe I'm missing something. What I'm referring to, so there is no question, if I could, Mr. Chairman, is on his page seven of his report, Item Number Three.

MR. BONESS: Neither Section 6.3 nor 6.4 yields a present price for their conditions precedent deregulation has not occurred. Now, it's your suggestion that deregulation does occur.

SENATOR CROFT: No, I'm saying if it doesn't. Isn't that what he says, "I am at a loss, therefore, to advise the committee on the sale price which will be applicable at the time of first delivery."

MR. BONESS: If the status quo prevails.

SENATOR CROFT: Which means no deregulation, I assume?

MR. BONESS: All right, and the reason he's at a loss is because -- it relates to the first sentence in that paragraph, which says, "At this time the State cannot determine its sale price because no rates have been set for Alaska gas at this time." That's why he's at a loss to tell you whether you're going to get Twenty Cents

or Two Dollars an mcf, because that rate making proceeding has not occurred yet. It will occur before gas flows.

SENATOR CROFT: Then what does he mean by, " if the status quo prevails through the time of first delivery"?

MR. BONESS: Meaning if no rate making hearing occurs before the time of first delivery there will be no rate established. I believe Mr. Moody went at some length to indicate how the various ways of rate making proceeding could come up. As you recall, he indicated there were a number of ways. The FPC could adopt a rule making proceeding and just decide to establish an Alaska rate as it did for the National rate. The producers could enter into contracts and file those contracts with the Federal Power Commission, and a rate could be established that way. And the third way a rate could be established is, gas would start to flow and the pipeline company would file a tariff, and the purchasers, or the producers' gas would file tariffs for sales of it, and the FPC would then investigate those tariffs and decide whether it is. One of those three ways of rate making will come about. It is most likely that will occur before the gas begins to flow. It's conceivable it will not.

SENATOR CROFT: And that's what he's referring to?

MR. BONESS: That's right.

SENATOR CROFT: When he says the status quo?

MR. BONESS: That's right.

SENATOR CROFT: And if it doesn't occur, if none of those three things occur, then there will have to be an addendum to the contracts or modification

MR. BONESS: There will have to be a rate established at that time, yes.

SENATOR CROFT: So as I understand it, with regard to point three, you agree that there is no price in these contracts but you think that by the time the gas is produced there likely will be.

MR. BONESS: That's correct.

SENATOR RADER: Let me ask a question here. As I understood it -- I think maybe you've answered the question and maybe you haven't, I don't know. These contracts, as I understand it, do not for a moment admit that the State is under the regulation or jurisdiction for purposes of sale of our gas, but what it does recognize is the purchasers are under regulation, because it has to go in a pipeline which is under regulation and that, therefore, we indirectly, because our purchasers are under regulation, that the price that we can get on an interstate commerce carrier here will be regulated because the purchaser is regulated; not because we're regulated; is that correct?

MR. BONESS: Yes, it is.

SENATOR RADER: There is no way to avoid that for any gas that goes into interstate commerce, is there?

MR. BONESS: Any gas that goes into interstate commerce for resale would be the problem with respect to the provisions we're now talking about, the regulation of natural gas companies. Even if we made a sale of gas into interstate commerce which was not for resale, the problem would still exist because of the Federal Power Commission's jurisdiction over the transportation aspects of the pipeline. They could, in effect, veto a sale of gas over which they did not have any direct jurisdiction by vetoing transportation authority, and they have done that in many cases. In fact, I was advised over the weekend that last week the Federal Power Commission, with respect to emergency sales in Tennessee Natural, which is not related in any way to the pipeline we're selling gas to, but in that proceeding they have a special procedure called emergency sales which allows gas to be sold for sixty days in an essentially unregulated fashion. The FPC routinely grants certificates. Nevertheless, Tennessee Natural negotiated a contract for Two Dollars and Seventy-Five Cents per mcf, which the FPC felt was too high and denied that certificate. They can apply the same kind of approach to the State. If we were to negotiate a contract for the sale of gas, for example, for boiler

fuel, which would be a direct use and the FPC wouldn't have jurisdiction over that sale, even assuming we were a person, they could veto and probably would veto the transportation aspects of that arrangement.

SENATOR RADER: Senator Croft.

SENATOR CROFT: I had a couple more. With regard, Commissioner Martin, to these people that you had asked to bid, as I understand it, competitive bidding and public bidding, you asked for competitive bids?

COMMISSIONER MARTIN: No, sir. We went though, two times, by national publication to express interest in having buyers for Alaska royalty oil or gas. In each case we indicated we wanted to have all expressions of interest but that we favored expressions of interest which leaned toward in-State use. I've expressed to this committee and others before that, at least at this time, not a great deal of interest has been expressed. I've given the committee my findings with respect to competitive sales in this situation and I've told them my view that competitive sales are going to be difficult, even though they're desirable, so long as we have fixed stated objectives, and some people would be better than others at fulfilling them.

SENATOR CROFT: Is competitive bidding, in your mind, the same as public bidding?

COMMISSIONER MARTIN: No, I think that you could make distinctions between the two.

SENATOR CROFT: I don't want to be overly technical, but I noticed that the approval of the request of Commissioner of Natural Resources to waive requirements of competitive bidding, that it actually says that, "Now, therefor, the Alaska Royalty Oil and Gas Development Advisory Board hereby grants to the Commissioner of Natural Resources its approval of his request to waive public bidding." What's actually meant was competitive bidding?

COMMISSIONER MARTIN: I would think so in that context, yes.

SENATOR CROFT: I assume, Mr. Boness, you'd say legally that there is no problem with that?

MR. BONESS: Senator, I haven't been involved in the drafting of those. I apologize for the error, but I assure you that it was not my intent and, I suspect, the intent of the Royalty Board to draw any distinction between public and competitive bidding.

SENATOR CROFT: But there is a difference between the two?

COMMISSONER MARTIN: There could be in some context; I don't think there is one intended there.

SENATOR CROFT: One final question, if I could. Commissioner Martin, before the Royalty Gas Advisory Board, I think you made some apologies to the Governor and said that what you had thought we had done here was harness a team

of powerful horses to plow a very rocky field. I'm curious with regard to, say, the Tenneco provision, or the switching provision and Tenneco, who said basically that they didn't think they would be able to switch; do you really believe that with that switching provision you're going to be able to take all of these powerful horses with you if you decide to go in some other direction?

COMMISSIONER MARTIN: I've always regretted that statement, right from the time I wrote it, Senator. First of all, we don't intend to switch. I've said that on many occasions.

Secondly, it seems to me the situation that would have to exist at the time any switch were desirable would be really quite an extraordinary one. But my point has been continually that I think that it's an important benefit for the State to preserve, simply because of the kind of flexibility that's afforded may turn out to be in our interest at a later time.

For political purposes, I think it would clearly be a greater expression of political faith for the Governor, for the Legislature or for others to say, "We're going all or none for one route." Quite frankly, that's the position I take. I think that's where we are going. But it does seem to me that it is at least

possible in the future that circumstances could change and that El Paso could be shown to be and concluded to be, by all the important decision-makers in this State, a loser in the process, and it could be at that time that Alcan, which is a second choice, far superior to Arctic, could be at some future time our only remaining alternative. If that situation existed it would not be any lack of credibility that would confront us, because our first choice would simply be out of the field and we would not be saying that it's a worse possibility; we'd simply be saying that that is no longer a possibility and then we could switch the support.

SENATOR CROFT: I understand that that wouldn't cause you a credibility problem, but Tenneco said it would cause them a problem. My question is, do you believe that if you switched you'd take Tenneco and El Paso with you?

COMMISSIONER MARTIN: My belief is yes, and I haven't read the transcript of their response. But I recall talking at length with our buyers on this issue really to ascertain their level of commitment to the route that the State favored. My feeling was that the buyers that we eventually sold to do have a deep commitment to the El Paso route. I never have heard them address the question that you just said and the context I just did, "What if it were only a choice between Alcan and Arctic, and

could you then with credibility switch and support another route?" I would think that their answer would be pretty much the same as mine, and that is, "If those are your two alternatives, yes." You could make a credible argument as between the two alternatives, so I don't even agree with their assessment and I don't think they answered in that context. I may be wrong.

SENATOR CROFT: Well, I guess the hearings will show whether they did or not. Let me ask one final question in that regard, with regard to this team of powerful horses, and if it makes you uncomfortable I don't want to belabor it, but I am curious as to exactly why you feel that way with regard to El Paso. I mean, it seems to me, and as Professor Tussing pointed out, that El Paso's primary sales area is California, and yet one of the areas of the country where most resistance to the El Paso project exists, if not the area in which the greatest opposition exists is in the primary market area of one of the three companies with whom you contracted; how can you really say El Paso brings to these contracts a tremendous ability when their track record of two years, more than two years now in California indicates just the opposite?

COMMISSIONER MARTIN: Well, I think I tried to address this question with you before, Senator Croft. I'll say two

things. One is, that's a subjective judgment I think a number of people are going to have to make on their own. In trying to assess that I've tried to do what I have with the others, and that is to get the broadest consensus as to which companies can help. Our Delegation is unanimous in feeling, to the contrary of what you've just suggested, that El Paso can be of help and should get gas under this contract, and that it will help.

It seems to me that in spite of whatever difficulties exist in California, their argument is enhanced by sale of the gas because they then can say that they will not only win the route but will have a gas supply to bring to their constituency, and that's the difference. The difference is that they are put in a position of being able to give gas to their consumers as opposed to simply having a pipeline certificated in their name but with no gas to go through it to their consumers, and that, I suppose, is a very important difference.

SENATOR RADER: Representative Parr:

REP. PARR: One final question, Mr. Chairman. Mr. Martin, in talking about what went on last week there's one point you went over in kind of a hurry and yet to me it is one of the rather difficult points. The reason that we're talking about going into contracts at this time is

very simple; we want to get some political clout, national constituency, call it what you will, right, to help us get the Trans-Alaska route ---

COMMISSIONER MARTIN: Mr. Parr ---

REP. PARR: Let me finish my question.

COMMISSIONER MARTIN: I'm sorry. You asked me "right" and I thought that was the question.

REP. PARR: I'm sorry, I'm leading up to it; beg your pardon. That was the reason that we were going into these contracts at all, as I understood it. So we thought, "Well, now, what kind of assistance are these companies going to give us?" The contract, I think, just says actively support; without looking back at it, that's my recollection of what it says. And we tried to get that made a little more specific, and we never got it last week. At least I never heard it. In fact, I think I phrased the question to the gentleman from Tenneco who had told us they had Seven Billion Dollars in assets and did a Five Hundred Million Dollar business. You know, I couldn't quite believe they weren't going to budget something for this effort. They weren't, or at least they haven't.

So would you mind commenting on that whole area, please?

COMMISSIONER MARTIN: Yes, Mr. Parr. I wish I could somehow communicate to you, in spite of your characterization of the issue, make it clear that my feeling is that that's

not the only reason. I tried very hard in my opening statement to lay out a number of areas that I thought were of equal importance in these contracts. So I'm going to lay it on you squarely, that in rejecting these contracts, should you choose to do so -- I want you to know that my view is that regardless of your own characterization, my feeling is that you would not just be rejecting whatever political clout you choose to assign to these contracts, but one of the best opportunities we have to accomplish all of the other objectives I laid out. Now, in terms of the political issue itself, which is one of many, let me say again, I don't think that you are going to get a quantifiable idea of what these companies will do.

Let me try to give you an idea of what I think will happen. First, they've already intervened in the FPC, as I discussed with Senator Croft. I don't think they were the difference, pro or con, in that fight.

Secondly, I think each of them will mount substantial efforts in support of the Trans-Alaska pipeline in Congress. Those efforts will consist of the retention of lobbyists, assignment of company personnel, and the development of information within their companies in support of that route, information which, quite frankly, would be very difficult to produce

in the volumes and to disseminate in the way that would be useful, without additional parties in the fight. In addition to that I expect that they'll do substantial work in their constituent areas to attempt to indicate to people the benefits of the Trans-Alaska line as a way to bring gas into their areas and will try to mobilize those people at a local level to deal with their Congressmen and Senators on the issue.

I also think that they'll participate with El Paso as the design, and the details of any El Paso route through Alaska that are put together. Both Tenneco and Southern have substantial offshore capability and substantial LNG experience. In my view, and I think in the view of others, they have an opportunity to substantially and materially improve the quality of the overall project once it's funded and to prove to Members of Congress and the Administration that they're capable of doing so as it's developed.

One of the problems with El Paso that's been pointed out in the past has been that El Paso has not done as well or as complete a job in its homework in terms of design in proposing this route as they could have. I think that both Tenneco and Southern have the capability to substantially improve that.

I think that generally categorizes the sorts of

things that they're expected to do. My guess is that overall the expenditures, while I can't give you a budget figure either, will be in the over Hundred Thousand Dollar category, and I also believe, it's my personal belief -- and I also believe that this view can only be made subjectively. In trying to deal with my own subjective judgment, I feel compelled not to try to rely on an individual judgment, but to check it with others.

I've consulted with the Congressional Delegation from beginning to end on this and they share, generally speaking, the advantages that I outlined. But I don't think that even the Congressional Delegation will be able to give you a dollar for dollar quantification of what will happen. They only know that it's very valuable.

REP. PARR: Mr. Chairman.

SENATOR RADER: I'm quite certain that we're not going to be able to conclude with the witnesses here. It's 12:00 o'clock now. The Senate goes in at 2:00 o'clock and we should be through at 3:00 o'clock. I know that Representative Chatterton has a series of questions that he wants answered, and I think there's still a number of unanswered questions that other members want to depose. It would be my suggestion that we recess until

3:00 o'clock. I don't think there's any point in coming back here at 1:30 for twenty minutes to try to put anything together between 1:30 and the time the Senate goes into session, although I think that we could have a good two-hour shot at it between 3:00 and 5:00, or if we want to go we can go beyond that.

Does that sound appropriate to the committee?

Now, unless I'm interrupting you right in the middle of a series of questions.

REP. PARR: No, a very short thing, Mr. Chairman, since I won't be able to be back at 3:00. I've cancelled committee meetings all last week for this and I can't keep on doing it. I'd like to ask one very brief one.

SENATOR RADER: Go ahead.

REP. PARR: The first thing I'd like to say is to summarize what Mr. Martin just said as I understand it, and I guess this is where we have subjective judgment disagreeing. First, I do think that perhaps my characterization is accurate. If it weren't for the chance to get a political clout we would be in no hurry to enter into any contracts, number one.

Secondly, that what Mr. Martin has just said, and if you listened to it carefully, he kept saying, "I think," "I believe," and "the Congressional Delegation believes," and he admitted, he said at the end -- not

admitted, he said at the end, "This is a subjective judgment." So what we're really face down to is, are we willing to subjectively have faith in these companies to really make a significant effort. They have been unwilling to quantify in any way the number of people they will assign, the number of dollars they will spend, or anything else at all. So we simply either have to have faith in them or not.

I'm sorry, Mr. Chairman, to take so long but that's the end of my statement, and I won't be here this afternoon.

SENATOR RADER: Do we have any further questions that cannot wait until 3:00 o'clock? We will stand in recess until 3:00 o'clock.

(Whereupon the hearing recessed at 12:05 p.m. and reconvened at 3:00 p.m.)

SENATOR RADER: The joint hearing will come to order. We have clean copies of two documents which should be made exhibits. The first would be the Federal Power Commission News Release No. 22868. It will be Exhibit 28.

(Whereupon Exhibit 28 was duly marked.)

SENATOR RADER: That one is entitled "FPC Judge Recommends Approval of Arctic Gas' $8.5 Billion Alaskan Gas Project." It consists of eleven pages. And Exhibit 29 will be Federal Power Commission News Release No. 22869, entitled

"Alaskan Natural Gas Fact Sheet," consisting of four numbered pages and three unnumbered attachments. Give those to the reporter.

(Whereupon Exhibit 29 was duly marked.)

SENATOR RADER: Exhibit No. 30 is a letter from Ruth A. M. Schmidt, Ph.D. of Anchorage, Alaska, dated January 30, 1977, consisting of two pages, addressed to the House Special Committee on Royalty Gas Sale, Attention Representative Clark Gruening. That will be introduced then as Exhibit 30.

(Whereupon Exhibit 30 was duly marked.)

SENATOR RADER: Did you want this read or just introduced as an exhibit?

REP. GRUENING: Introduced as an exhibit. Why don't we make copies for everybody?

SENATOR RADER: Besides, I hate to keep our witnesses longer. Senator Poland, why don't you join us up here? It would be more convenient, I think, for participation, and if Colletta or Senator Butrovich come we can make some other arrangements.

SENATOR CROFT: Mr. Chairman, I might indicate that at 3:30 I'm going to have to go to a Judiciary Committee meeting. When that's over I'll return here.

SENATOR RADER: Fine. Under those circumstances, Senator Croft, do you have any particular further questions of

these witnesses?

SENATOR CROFT: I do, but I think Mr. Chatterton and Mr. Hayes do.

REP. CHATTERTON: I'll yield to you.

SENATOR CROFT: Let me ask, in light of the fact, Mr. Chairman, that we've now been furnished pages two and three of the Power Commission news release that summarized in ten pages Judge Litt's decision in that regard, (or eleven pages) and the two and three that we had were a part of another press release of the same date from the Federal Power Commission, and the two and three that we now have have some information that refer to prices, which is what my questions were about, Commissioner Martin and Mr. Boness. On page two there's some obviously different language. Instead of describing the El Paso and the Alcan projects he talked about rolled in prices and city gate. But on page three in the next to the last full paragraph of that page and in the last full paragraph, he makes two comments.

In the middle of the next to the last full paragraph he says, "The important missing ingredient was sales contracts by any of the thirteen producers who hold interest in Prudhoe Bay reserves." Then at the last of the last full paragraph he says, "The producers, like G. B. Shaw's dinnertime companion, have a price at which

they would sell their 'service,' and all their protestations to the contrary cannot hide that they are mainly dickering over price. Then on page ten, it seemed to me, he made another reference to the fact that the producers' failure to sign sales contracts indicates where their concern lies.

I understand your feeling that the State got the best possible price under the circumstances, but isn't that a pretty clear indication that Judge Litt believes that it's the producers' opinion that if they wait until a later date that they can get the highest price, and his feeling that the reason they are waiting is solely to get a higher price?

COMMISSIONER MARTIN: Yes, sir, we think they're dickering with the FPC over price. Let me put that in some perspective in terms of what that means to us. They definitely are trying to deal with the FPC and to maximize their advantage. But let me point out that it may or may not be the case at a later time that they get a better price. For instance, it may be they don't or, on the other hand, it may be that some get a very good price under a deregulated situation and others get a worse price. But whatever that price is, under the contracts we have we're going to get the benefit of the best deal that anybody makes. So we basically tied ourselves to the

very best that anyone can do.

The second factor is simply to, I think, look just very briefly at the fact that the significance that he attaches to it beyond that is simply not to regard it as an important influence on the decision, but simply his irritation in not having information in regard to who the buyers will be for financing purposes. So I think that the State still stands in a better situation by having sold and created some kind of an incentive in favor of the route we support, as opposed to these guys who, you know, are going to sell -- just like Columbia -- to people who believe that they'll get the gas whichever way the pipeline goes. Let me ask Mr. Boness to respond a little further.

MR. BONESS: Yes. There's a basic difference between the producers and the State that has to be faced up to, and that is, the producers get to decide whether the gas is ever produced or not. The State does not find itself in that position.

The producers are telling the Federal Power Commission, "If you don't set a high enough price for us we're not going to sell the gas, we're never going to commit it to the interstate market; we're not going to produce it; we'll continue to reinject it as long as we're allowed to do so." And in that context, they are

dickering with the FPC.

As you recall, both Rush Moody and Dr. Swanson indicated that the range of the price that could be set for this gas is very wide. That gas could be set as low as Twenty Cents because of the problems associated with establishing gas prices for a reservoir which has both oil and gas in it, or it could be as high as the national price, which is now a Dollar Forty-Two, and conceivably it could be higher. That's the dickering that's going on between the Federal Power Commission and the producers. But the State does not participate in that threshold decision with respect to whether the gas is produced, except for the conservation statute, but you have to realize that's a limited powers kind of statute.

If I may, Senator Croft, I would quote to you from a statement made by an attorney for Exxon to the Federal Power Commission at the time the Judge was asking why they wouldn't enter into contracts. I think it really offers a great deal of insight into where the producers are at. And with the committee's indulgence I would do that, if I may.

Mr. Erck, (who is the attorney for Exxon) said, "First of all, Exxon's position with respect to the negotiation of definitive gas purchase and sales contracts

concerning the North Slope of Alaska has not changed. If a favorable regulatory climate exists and the State of Alaska has approved a unitization agreement and operating plan at the time the Commission certificates a viable transportation system, Exxon will enter into negotiations leading to the sale of gas from the North Slope pending the resolution of other uncertainties of the Commission. The Commission's removal of such disincentives as Order No. 53 and Opinion 740-B would improve the regulatory environment for gas purchase and sales contracts. Apparently the Commission is not totally unaware of these impediments since it has issued Opinion No. 766 and 767 in Dockets No. (and I won't burden you with those). These are progressive opinions, and hopefully indicate a trend towards improvement of the regulatory climate.

"Now, the pervading attitude of the Commission at the time one of the competing projects in this proceeding is certificated is inextricably connected to Exxon's willingness to negotiate definitive gas purchase and sale contracts.

"So let me hasten to reaffirm that we do not want to delay this pipeline. It is in our interest that the gas pipeline proceed as fast as possible. And as far as we know -- as far as our willingness to proceed

in light of what I have indicated, we would foresee that gas should be deliverable into the line when it is laid."

Senator, as I read that, and other statements of a similar nature have been made, I think the producers are telling the Commision that they want a favorable regulatory climate, and what they are really doing is tying their ability to withhold Prudhoe Bay gas to the overall position that the Federal Power Commission has taken on any number of issues of a regulatory nature, which are not necessarily related at all to Prudhoe Bay gas. They realize that they have the upper hand at this time, and I think they are making the most of it.

The State doesn't participate in that kind of dealings with the Federal Power Commission. I think that's what Judge Litt is really referring to. Judge Litt believes it is in the national interest for the producers to commit their gas at this time, and maybe it is; but the producers are taking the position that they want to do everything they can to "create a favorable climate," regulatory climate.

SENATOR CROFT: One further question in that regard. Your statement is that we're going to get whatever the comparable private sales will produce, even if the companies are correct in their efforts, that we'll benefit from them. In that regard, what would be your

response to Mr. Moody's comment on page eight at the top, number five, when he says by these contracts you have limited yourself to whatever private sales produce and you've given up your capacity to insist on a higher rate?

MR. BONESS: That again goes to the question of whether the State can make any separate arguments that it, as a State and owner of royalty gas, should be treated better than the producers. As I indicated this morning, there is certainly no compulsion and legal requirement that the FPC find that because the State will dedicate its share of the revenues to public purposes that the State thereby is automatically entitled to higher revenues. As I indicated, I believe that argument ultimately comes down to requiring consumers in Midwestern and Eastern States and the Lower 48 States generally, to pay a higher price which, in effect, is transferred into the State treasury and I think when cast in those terms, it's an argument very likely not to succeed before the Federal Power Commission.

SENATOR CROFT: You do agree with him that through these contracts we're giving up our right to make that argument?

MR. BONESS: No, I wouldn't even agree with that, Senator, and here's why -- if, indeed, the argument is a valid argument, then it can be made that our gas purchasers

should be allowed to pass that through. Our contract says they can pay us whatever they're allowed to include in the jurisdictional rate base. To the extent that that argument can be made, we can make it and say they should be allowed to include it in their jurisdictional rate base. If the argument has any validity, I believe that would be as valid in that context as in the context of simply establishing a higher price for State royalty gas.

SENATOR CROFT: Even if we've tied ourselves to whatever they agreed to privately?

MR. BONESS: Well now, you see, that's the point I made this morning. As a general matter, people are saying we are tying ourselves to the producers, and in practice that's usually the case. But as a technical, legal matter, the contract is drafted to allow us to receive whatever price our purchasers are allowed to include in their jurisdictional rate base. If the argument has validity that the State should receive a higher price because of its royalty gas, then that argument can be put forward before the FPC with respect to the price we charge our purchasers, wholly independent of the question of whether or not the FPC can regulate the producers and whether or not they can regulate us.

SENATOR CROFT: So your position is that we've not given up on it, even if he feels that we have.

MR. BONESS: Well, I haven't discussed that point with Mr. Moody, but I believe what I have said is correct, that we could make that argument and if it does have validity then the purchasers would be allowed to include the rate in their jurisdictional ---

SENATOR CROFT: You don't question that he doesn't take that point of view?

MR. BONESS: Well, if I had time I would read it, and could I respond to that and say what I think he's saying there?

SENATOR CROFT: You haven't had a chance to go through this before?

MR. BONESS: I have read it, but I would like to read that again if you're asking me to interpret what Mr. Moody's position is.

COMMISSIONER MARTIN: I might also say, Senator, he doesn't address here, but I understood that he addressed, at least in some of his testimony, the probability of that argument, aside from the technical ability of it to ever be made, the probability of it ever succeeding, which, at least in my understanding, he feels is extremely low.

MR. BONESS: I have read it and to the extent that I do disagree with him, I believe we can still make the argument in the context of the present contracts, and I believe we have not tied ourselves exactly to the price

the producers are allowed to receive. We have tied ourselves to the price the pipeline companies are allowed to include in their jurisdictional rate base. Therefore, I believe we could make the argument that we, as a State, ought to be treated separate and differently.

I would also point out that even as a legal matter I am not convinced we would want to make that argument. As Mr. Moody, himself, pointed out, or perhaps it was Dr. Swanson, pointed out the other side of that argument is the State should receive less because the State has incurred no risk and, therefore, it would have to be a well researched and carefully thought out decision to pursue that line of argument, recognizing that if we did pursue it somebody would take the other side of it.

SENATOR CROFT: Thank you.

SENATOR HUBER: Mr. Chairman, I have something that came up.

SENATOR RADER: Senator Huber, go ahead.

SENATOR HUBER: I just wanted to get something clear that came up out of Senator Croft's questioning. I believe I understood you to say the companies could withhold the production to gas, and this is the context I wanted to ask it in. Doesn't the State still have the right under lease terms to cancel leases for failure to produce when the ability to do so is possible but not exercised by the lessee? Don't we have that right?

MR. BONESS: I believe that's correct, Senator. But if there's no pipeline in which they can deliver the gas then I doubt that we can cancel the lease.

SENATOR HUBER: Well, if there's no way to use the gas, let's put it that way.

COMMISSIONER MARTIN: That's right.

SENATOR HUBER: If there is no way to sell the gas. I hate to see them keep tying this to an FPC controlled pipeline. I wanted to make sure that there wasn't something that was cancelling or changing the provisions that are in the lease that the State has the right to force them to produce.

MR. BONESS: You're correct, Senator.

SENATOR HUBER: Thank you.

SENATOR RADER: Mr. Chatterton.

REP. CHATTERTON: Mr. Chairman, thank you. Mr. Commissioner, I have a series of questions that you will have to accept me on faith are not meant to be controversial, argumentative or in any way entrapment questions. Please accept me on faith. The reason for the series of questions will be to put into the record something that I believe should be put into the record from a document that is too much, too voluminous, in the interest of efficiency, to make an exhibit. So I will attempt to get the salient points of that document into the record

through the question and answer route.

So, I'll start my questions: are you aware of a report that was prepared and presented by H. K. Van Poollen to your Department dated January 1976?

COMMISSIONER MARTIN: Yes.

REP. CHATTERTON: You also are aware that that report, in effect, includes the comparison of some twenty-nine separate forecasts based on various operating programs and production schedules for the Prudhoe Bay field?

COMMISSIONER MARTIN: Yes.

REP. CHATTERTON: Are you aware of this section on page five, and I will quote, and I will quote in context. It's on page five of that report entitled "Prediction of Reservoir Fluid Recovery Sadlerochit Formation Prudhoe Bay Field", and again dated January 1976. On page five and under "Qualifications" that the authors placed before here, before you, it says, "The numbers in this report should be considered relative rather than absolute. Reservoir performance predictions on a field without production history are approximate at best. Absolute values should be used with caution, but relative values can be used to compare production schedules with confidence", relative to one another, absolute number not. Do you concur with that premise?

COMMISSIONER MARTIN: Yes, I concur with that statement.

REP. CHATTERTON: I would now like to ask you if you would concur with this statement which appears on page three of the aforementioned report, and I will quote in context. It's under "Summary" of the report, and it's item two under that summary. It says, "The highest oil recoveries were obtained under conditions of an aquifer supplemented by water injection and no gas sales." I'll get the numbers later. Do you concur with that?

COMMISSIONER MARTIN: Mr. Chatterton, let me say before I agree to this, I don't have the document before me. I've studied it and ---

REP. CHATTERTON: I'm not trying to trip you up.

COMMISSIONER MARTIN: I understand you're not and I'm not trying to be defensive against that. I just want to say as a preface to all my answers, I'll give you the best answers I can, but within the context of being the Commissioner and not a technical expert with regard to this study. I believe that that conclusion is right and that sounds accurate from the study, as I recall.

REP. CHATTERTON: Maybe we can get it this way. You, as Commissioner for the Department, did accept the report?

COMMISSIONER MARTIN: I've accepted the report, and let me say that there is still work being done on that report. As a matter of fact, as you may know, one of the reasons we brought Mr. Hamilton here last week was to update the

committee on the new work. The trend of the new work is similar to the work in the report you have in your hands.

REP. CHATTERTON: I believe his testimony, or an answer to a question was that trend of the new work that had been accomplished to date indicates that's there is no substantive change to the findings of this report.

COMMISSIONER MARTIN: That is accurate.

SENATOR HUBER: He didn't testify; isn't that clear? He did not testify, he went back without testifying.

REP. CHATTERTON: He answered a question to our Chairman from the floor.

SENATOR RADER: I think that's correct. We asked him if the updating material would substantially change the material previously submitted to the committee, and he said that he did not feel that it would make a substantial difference.

COMMISSIONER MARTIN: The answer is yes, it generally tends to bear out the work already done.

SENATOR RADER: Although he did not take a seat and testify, he stated that from the floor.

COMMISSIONER MARTIN: In any event, the answer to your last question is yes, I recall that statement.

SENATOR RADER: I'd like to ask the reporter, did the reporter take down that dialogue between me and Mr.

Hamilton when I asked him about his testimony, and I think Senator Huber also at the same time suggested that he would be the best judge of whether or not he should testify.

MRS. SANDERS: I've taken down everything, but that notebook is not here; it's at my office.

SENATOR RADER: If it's important, I'm sure we can get Mr. Hamilton back.

REP. CHATTERTON: I do not think it's important as far as I'm concerned, Mr. Chairman. Thank you, I will continue. I would now like to read to you off of page seven of the aforementioned report and under "Recommendations" there are three, and this is half of recommendation number three. In the interest of time I'll read half. I'll read it all if you like. It says, "Although the prediction runs made in this study indicate that early gas sales will generally result in reduced oil recoveries, it should be recognized that important economic factors were not included in any of the boundary conditions." And I again, Mr. Commissioner, call your attention to the "early gas sales will generally result in reduced oil recoveries." Realizing you're not testifying expertly, you do accept that part of the recommendation of the report?

COMMISSIONER MARTIN: Yes, that there were not economic parameters set on the various variables.

REP. CHATTERTON: Thank you. Now, just to get into the record some numbers, I would now like to go to Table Number One of that report, which is a tabulation of the twenty-nine runs of various operating conditions and production schedules forecast for the field, to give this committee and the record some ideas of the importance of gas sales versus no gas sales.

There's actually four different conditions here as far as operating conditions and production schedules. I'll take condition one first for a comparison. Keeping common will be no aquifer activity. Production will be at the rate, black oil production at the rate of 1.2 million barrels per day. All other conditions will be the same with the exception of gas sales.

Run number one gives an estimated cumulative oil recovery from the Prudhoe Bay field of 7.38 billion barrels. That run, there is no gas sales.

Run number four is an ultimate economic recovery of 610 billion, that is 1.28 billion barrels less where again all conditions are the same excepting after two and three-quarter years following the commencement of oil production gas production will start at the rate of two billion cubic feet per day. Will you accept this as I've read it correctly?

COMMISSIONER MARTIN: I think so, Mr. Chatterton. It sounds like one of the scenarios.

REP. PARR: In the interest of time I will not carry this on other than to say that anyone referring to runs seven as compared to runs thirteen will see the same type of difference between ultimate recovery of gas sales versus no gas sales. They will see the same results between runs number ten and number sixteen, no gas sales and gas sales; again the recovery will be lower in this case by the amount of 1.24 billion barrels -- not million, billion. And again you'll see the same thing between runs twenty and runs twenty-five. If you'll accept that I will go to the next question, and this ceases to be necessarily non-argumentative or non-controversial or non-entrapping. So it's varied there.

My question is one where we have to hypothesize. If we had had gas cap producibility at Prudhoe Bay last week and a transmission system from Prudhoe Bay to the South 48, do you believe that possibly, because of quasi-emergency situations, the South 48 might have called upon Prudhoe Bay gas production even though it might well have been in the disinterest of Alaskans?

COMMISSIONER MARTIN: Rather than speculate on what they might have done last week, let me just say that it's clear to me (I consulted with Mr. Boness) the Federal

Government certainly has the power in time of national emergency to do that. It seems to me that that is a power limited to extraordinary circumstances which could well exist under certain circumstances. Whether last week's would have qualified, I really don't know.

REP. CHATTERTON: Thank you. The last question, Mr. Chairman, Mr. Commissioner. As Commissioner of your Department, would you be fairly certain that you would support the findings of your Oil and Gas Conservation Committee even though their findings might strongly recommend that there not be any export of associated gas from the Prudhoe Bay field?

COMMISSIONER MARTIN: I've been on the record pretty clearly on this, in the FPC, and in this committee, and publicly, Representative Chatterton, saying that I believe the decisions of the committee, so long as they are legitimately guided by the confines of the State Conservation Statute, will be a controlling factor in this matter and not overturned by other political factors. So in that regard, I have advised, under some pressure by the FPC Hearing Judge, advised the Federal Government that they could not have an absolute guarantee or absolute predictability with regard to rates of production from the Prudhoe Bay field.

REP. CHATTERTON: Thank you, Commissioner and Mr. Chairman.

SENATOR RADER: Any further questions? Representative Gruening.

REP. GRUENING: There is one provision that concerns me and I'm wondering whether the three purchasers, any one of the three purchasers insisted on its inclusion. That has to do with the replacement of gas taken back at one and one half times the rate. Was Tenneco one of the purchasers, or the purchaser to insist on that provision?

COMMISSIONER MARTIN: They were the major purchaser to insist on it. The others asked for it and indicated that they wanted it, and we included it in all the contracts to make them uniform. I should point out that this was clearly a term that allowed us to come to an agreement with Tenneco and without it we would have been unable to do so. If they had not been in we might have been able to negotiate the others out of that.

I should also indicate, if it's of interest to you, Mr. Chairman, that I assume you appreciate the limitations of that additional fifty percent recovery term.

MR. BONESS: No, the first recovery, everybody demanded that.

COMMISSIONER MARTIN: Yes, the first recovery, everybody demanded. It's the additional fifty percent that was primarily demanded by Tenneco, was asked by the others,

and we included it to make the terms uniform.

SENATOR RADER: Any further question of any members, or Senator Poland?

COMMISSIONER MARTIN: Senator Rader.

SENATOR RADER: Yes, did you wish to sum up?

COMMISSIONER MARTIN: Senator, I don't want to make a lengthy summary. I just want to go back a little bit, and I'm not going to review all the points I made this morning but I don't want to leave the committee without trying to stress again that there's no question that the centerpiece, or the most important aspect, or the most important aspect of these contracts now relates to the fact that we can get whatever support, political or substantive or otherwise comes to us on the gas line route issue. This is the only time it's important. It may have been important somewhat earlier. It won't be important again.

But I do want to add to that that the other provisions in this contract, whether they come from the 13-B argument, or Mr. Moody's theory of last year, or the fact that we've negotiated a very good price term, or the fact that we've negotiated good terms for take-back, are extremely important aspects of this contract, and I think the committee must take very seriously the possibility that certain of these terms cannot be renegotiated and put in a new contract. I do not think that, as your

negotiator you can act with absolute certainty that those terms are going to come our way every time we sit down to negotiate gas contracts. I'm not saying we can't accomplish them again; we'll certainly try to. But I do not want to leave the committee with the impression that they are automatically to be included in any contract, or that they can be protected in any subsequent contract at a later time. They came hard and we had some very difficult negotiations to get there.

Let me indicate just very briefly, at least on a couple of those points, just to give you an idea of why I think that it may be difficult in the future. If you consider the situation that we'll be in later, there are several factors that deal with the issue of price. One is, of course, the fact that I tried to bring up of the institutional constraints that we have on royalty gas contracting.

If we are caught in a crunch where the State does not have a position and does not have a contract, yet we get caught in a situation where perhaps Arctic is certified, if we lose support and if this is a fact, we're losing support and Arctic is certified, we are then under a time pressure that we are not now under and our buyers will know that. They will know that our alternatives are limited and they will know that they

have us much more at their mercy than they do at the present time. I'm not saying that will happen, but it could put us in a bargaining position we're not in now.

At the same time, if the State is the last one-eighth to sell, if the producers go ahead and sell, consider the alternatives that we face. By selling now and including the term that gives us the best price, we automatically benefit by the very best deal that any producer makes.

If we wait and we are one of the last eighths, or we're the last eighth or the last percentage to sell it could very well be the case that one of the producers has made an extraordinarily good deal. It will then be our job to try to make a better deal than they made, and I should point out that that will be a good deal more difficult to equal or surpass than it would be by simply taking advantage of it right now.

At the same time, I think that once in-State uses are developed and the present period of uncertainty is past, so that we know what it is we're going to use our royalty gas for, we can offer less to buyers. Under the present circumstances, our buyers think they're going to get most of our gas and we think we're going to use most of it. But as we continue to develop in-State uses they're going to know that they're going to get less.

And in the case of a company like Tenneco, they're interested in fairly substantial volumes of gas. They have other alternatives, as to other gas companies such as Algerian projects, Russian projects or other large fields, and as the amount that they know they will get from us diminishes, I think our field of negotiation diminishes somewhat also.

I might also indicate, if there is any action -- we've been dealing in these hearings on many occasions with possible but unlikely situations and I've been, I think, fairly frank in admitting what is possible in trying to give you an idea of what is probable. One of the things that may well happen if we wait, and this goes to the idea of future negotiations, is that if Congress is likely to take any action with regard to controlling gas in the future, my guess is that they will take it with respect to uncommitted gas. There is no reason that Congress should reward people who are presently withholding their gas from the market. If I were a Congressman, I would not lean heavily toward the position of favoring the producers who are now dickering with the FPC. I would lean toward favoring the individuals who have committed their gas and attempted to make it known how they're going to put it into the national consumer supply.

So I think that all of these factors added up provide extremely cogent reasons for considering that some of these terms may be difficult to immediately recapture. As I say, I'm not saying it can't be done, but I'm saying that it's difficult and we ought to acknowledge those factors. It's a calculated risk that has to be considered. I think the Legislature has to consider it as it considers these contracts.

SENATOR RADER: Representative Gruening.

REP. GRUENING: That raises a question. You mentioned the disadvantage we might be at in terms of just selling it for the price, for a certain price if the Arctic route is certified. Rush Moody's testimony was that our one-eighth is very crucial to the financing of that line. He, frankly, didn't see under present economics how it could be financed without the eight-eighths. Wouldn't that make you conclude that our one-eighth share would have some leverage in dealing with somebody in selling our gas?

COMMISSIONER MARTIN: Yes, but we'll have exactly the same leverage in that regard whether or not we've gone into these contracts. If Arctic is certified it will have to be with the knowledge that it will not have state royalty gas. Whether or not we sign these contracts, that will be the case. There will be, of course, the strong feeling

that they will get our gas one way or the other, but as I see it that argument doesn't go to whether or not these contracts should be approved.

REP. GRUENING: And conversely, if El Paso is selected and we don't go into these contracts, do you see any reason to believe that we would be at any disadvantage in dealing with El Paso or anybody else that is building an all Alaska line?

COMMISSIONER MARTIN: For some of the reasons I just explained, yes, I think we would be at a greater disadvantage than we are now, particularly if all of the other buyers have sold or are in the process of selling and that one or more of them have driven a particularly excellent bargain. Under these contracts we have the benefit of that bargain. Without these contracts we would have the duty of trying to come up to it or surpass it and, depending on what that is, it might be a very difficult task.

REP. GRUENING: Given the fact that we might know better what our in-State uses are, we may only wish to sell a portion of it; isn't a spot sale, or a sale of a smaller amount, sometimes not able to bring a higher price?

COMMISSIONER MARTIN: Mr. Gruening, that's one of the reasons that I've focused on something that I don't think people are too interested in, and that is the institutional

constraints under which we operate. To be very frank with you, I don't think our system is set up to do a good job of spot selling of royalty oil or gas and I don't think it will be so long as we have to negotiate with somebody and then go through a Royalty Board and the Legislature. It simply asks the buyer to do too much. It asks them to have the State assess its position, negotiate with them, and then wait for a period of months while economic conditions change, to have it approved. So I think that spot selling, while it's a possibility, represents a dim possibility for ever being a major policy of the State.

REP. GRUENING: I might suggest, Commissioner, that one of the reasons this hearing process has been maybe a little longer than it might be is because the contracts are being offered for other than for money return; they're being offered for political purposes.

COMMISSIONER MARTIN: Absolutely.

REP. GRUENING: They are, as you admit, quite unique, probably very unique.

COMMISSIONER MARTIN: That's right.

REP. GRUENING: But anyway, I do want to nail down exactly what was behind this report. Could you identify for the record exactly -- this is the report upon which you feel that you're in compliance with this 38.05.184(d), I guess.

COMMISSIONER MARTIN: Yes, in the document cited therein. But also we filed, Mr. Gruening, this report here, which is the more formidable statement. The blue document is actually a summary of this one. But it also references all the other documents that are a part of the analysis.

REP. GRUENING: So you're saying that all the references on page eleven of this January 7, 1977, report are included as constituting a report showing the immediate and long-range gas needs?

COMMISSIONER MARTIN: That's right.

REP. GRUENING: This morning it was just the one report, and now it's the whole ---

COMMISSIONER MARTIN: No, I think I mentioned the reference reports, Mr. Chairman.

REP. GRUENING: Oh, the entire list of references would be included?

COMMISSIONER MARTIN: Yes.

SENATOR RADER: Do you have anything further? Any further questions of the Commissioner or Mr. Boness? Thank you, gentlemen, both very much.

We have the Lt. Governor with us, who said that he would like to make a very, very brief statement.

COMMISSIONER MARTIN: Mr. Chairman, I take it the committee is aware of the relative schedules of Mr. Boness and myself; that's been communicated to the committee?

SENATOR RADER: I have a schedule and I believe Mr. Gruening has a schedule. Yes, we both have your schedules. I don't know whether Senator Poland has a schedule.

SENATOR POLAND: I do.

SENATOR RADER: You do.

SENATOR POLAND: Yes.

SENATOR RADER: And I assume Senator Sackett. Commissioner, I did not give Mr. Sackett a schedule.

COMMISSIONER MARTIN: I sent him one.

SENATOR RADER: All right, fine.

LT. GOVERNOR THOMAS: Mr. Chairman.

SENATOR RADER: Lt. Governor.

LT. GOVERNOR THOMAS: Thank you very much. I'll be very brief, Members of the Joint Committee. I wanted to just say a word or two regarding the other than monetary aspects of this contract, going to the political, public information, generally gaining support in the rest of the nation for the route, that most of us, I think eighty-five percent of Alaskans, wish to see win out.

I just received a copy of a Resolution that has been passed by both Houses of the State of Alabama, and I'd like to turn that over to you, Mr. Chairman. I'll read only the last Whereas and the first Resolve clause.

"WHEREAS, this contract must be approved by the legislature of the State of Alaska; now therefore

"BE IT RESOLVED BY THE LEGISLATURE OF ALABAMA, BOTH HOUSES THEREOF CONCURRING, That the State of Alabama urges the Legislature of our sister state, the State of Alaska, to lend its approval to this contract and to take the necessary steps to the end that the contract will be ratified and the natural gas can be expeditiously transported for use by our citizens and industries."

Mr. Chairman, that I think, in conjunction with a letter that you all have received a copy of, the letter from Jerry Beasley, Lt. Governor of Alabama, indicates the kind of friends and allies and support that this contract we're dealing with, our surplus royalty gas, can engender.

I have one other point I would like to make, and this is from the point of view of one who expects to go out and do a selling job, radio and television, wherever possible, as I've done before, and that is to say that with the passage of this contract, your endorsement of this contract, we will have an awful lot more horsepower, the ground will be well laid for us to go on.

I would say that it's probably not so important that it pass as that it would be very detrimental if it did not pass because our opponents would quickly get the word around the country that the Legislature of Alaska saw fit not to endorse this proposal, and it would be

interpreted, I'm sure, and I see really no easy way or any way at all overcome the interpretation that this would show "Alaskans really don't care which way the gas flows." So from that point of view, I would urge you to be as hasty as possible, while at the same time taking plenty of time to deliberate, and having sat where you are I understand that you're moving as rapidly as you possibly can right now; but I think it would be a great assist to all of us who will be out, and our allies such as the people in these other states, in trying to gain approval in Washington of the all-American delivery system.

That's all I have to say, Mr. Chairman.

SENATOR RADER: Mr. Lt. Governor, can we enter Exhibit 31, the Resolution to which you just made reference?

LT. GOVERNOR THOMAS: Yes, sir. I'll leave it right here.

SENATOR RADER: That will be Exhibit No. 31 according to my numbering system. Is that correct?

MRS. SANDERS: Yes.

(Whereupon Exhibit 31 was duly marked.)

SENATOR RADER: Just a second. Do you have any questions of the Lt. Governor, or did you wish to submit to questions here?

LT. GOVERNOR THOMAS: I'd be happy to, but I'm not the technician regarding the contract.

SENATOR RADER: Does anybody have any questions of the Lt. Governor? Thank you very much, sir.

LT. GOVERNOR THOMAS: Thank you.

SENATOR RADER: Are there any other persons who desire to be heard on the subject that we've been discussing and hearing so much about the last three or four days?

Under the circumstances, these joint hearings are adjourned with no intention to reconvene.

(Whereupon the hearing was concluded at 4:00 p.m.)

SENATOR RADER: The committee will take that up at a later date. Commissioner Martin called me and asked if he might take the stand for a few moments this morning to clarify testimony given yesterday or make additional points. Commissioner, glad to have you back.

COMMISSIONER MARTIN: Senator, thank you. Then I will be very brief. I know the schedule you have. I really had two purposes. The first I see has been taken care of after coming down. I was concerned -- as you said yesterday, I don't think -- notwithstanding some remarks that were in an adversary proceeding, we want to share everything with the committee. I wanted to bring down the press release from the Federal Power Commission but I see that the committee got it about the same time we did. It was probably a bonanza for the telephone company

this morning, as I think it was telecopied about three different ways. In any case, I have several extra copies of it here and I also have one copy, Senator Rader, of something we're doing now, and that is we're telecopying up what we think at least are pages that have something to do with the State in the four hundred and thirty-three page or four hundred and thirty page decision. We're making arrangements to have the opinion itself flown up, but it looks like the best we're going to be able to do, even with good weather, is to get it up here on the first plane tomorrow morning from Seattle, which means 9:00 or 10:00 o'clock, as I understand it. We'll take a look at it immediately and try to give you the best summary we can late in your hearings tomorrow afternoon, if that's acceptable to the committee, and try to duplicate copies for everyone as a part of that.

I might just say that in looking through the decision, just very briefly, Senator, for those -- has it been distributed? Well, I'll be glad to make these copies available to the committee. I didn't bring enough for everyone, but let me pass them around. I understood that the committee had been distributed copies but ---

SENATOR RADER: I don't know whether all the committee has. I see that this area here though all has copies.

COMMISSIONER MARTIN: Just very briefly and I don't intend to summarize this at all, Senator Rader. The decision is extremely heavily weighted in favor of Arctic Gas, substantially more weighted than we had expected or I think most had expected. It takes up most of the opinion really dealing with the benefits of Arctic Natural Gas' proposal which is regarded by the judge as superior on most -- on every ground for the permit.

And then on page nine near the bottom there is a short summary paragraph dealing with El Paso, which the judge says that, "if Arctic Gas is unable to accept a certificate, El Paso's proposal, with modifications, would also meet the public convenience and necessity." He goes on to call it a "viable" proposal and then criticizes it on a number of grounds following. A short summary of the Alcan route follows on page ten of the lengthy memorandum in which he says, "As to Alcan, Judge Litt said the record does not support even the possibility that a certificate could be granted it. Its design is clearly neither efficient nor economic since the pipeline is undersized." And then goes on to criticize it on a number of other grounds, putting it sort of in a third position in his release. So, I think at the very minimum we can regard both of the choices that we favor as possibilities for Alaska taking a very substantial blow

in this Hearing Judge's opinion this morning, probably Alcan slightly more than El Paso.

I also will give you the first five pages of approximately twenty pages we hoped to telecopy yesterday. I don't have copies of these, Senator, which seem to affect the State. And there is some good news and some bad news. I might say in view of the recent letter that you just read from Farmland that there is at least some disagreement on that because, contrary to their assertions that the State is opposed to the economic development, Judge Litt finds that we are so much in favor of it that he finds it irresponsible. So, it's a can't win situation. He thinks we are going too far and Farmland, apparently, not far enough.

With very quick reference to that, let me say that so far as I'm aware, we have opened our files one hundred percent to the committee and that communication that Senator Huber talked to has been, so far as I know, either forwarded to the committee or made available to it along with all the other information. I don't want to take the time of other witnesses now to respond to that, but I assure you I'll be more than pleased to do so at an appropriate time.

Two very quick points, Senator. First -- and they both relate to what I think were factual misrepresentations

based on testimony given yesterday that may have been either members' misunderstandings or my failure to explain myself properly. First, I understand that it was indicated last night in some news reports that people couldn't understand how the state would oppose the treaty. I specifically said yesterday, that without actually seeing the treaty I couldn't take a final position on it, but the state in no way intends to oppose the treaty and in fact supports the enhanced relationship with Canada on all matters including energy matters. And, I want to be very clear about that now. We simply -- I'm not going to say we absolutely won't until I read the words and I don't think you'd expect me to. But I see no chance that we would and we don't want to and we don't intend to. So let that be well understood.

Secondly, there apparently was some substantial misunderstanding about whether or not the state could take the gas off under this contract in the state, use it for a petrochemical plant and then export the results of that process. The answer to that is unquestionably "yes". There is no qualification at all that the state must then subsequently utilize all the products from such a process in the state. We have the total right to take the gas off under this contract so long as it is used in the state for some process except liquefaction for export.

And there is no limitation on that in terms of utilization of the product.

One final very quick matter and that is on the matter of price. We do disagree with some of the characterizations about the state not getting the best price. We do believe that we have gotten the best price under the circumstances and tomorrow, as I indicated, after hearing the testimony of some of your consultants, Senator, we'll be prepared to respond to that at the end of the hearings as the committee sees fit.

SENATOR RADER: Are there any questions of the Commissioner?

SENATOR HUBER: One quick one.

SENATOR RADER: Senator Huber?

SENATOR HUBER: Mr. Commissioner, you might ask the judge there when he is finished with his crystal ball, knowing what's in the structure down there, to send it up to you so you can give it to your Department of Oil and Gas so we can get on with determining what we should be taking up there.

COMMISSIONER MARTIN: We'll ask them that, Senator.

SENATOR RADER: Representative Chatterton?

REP. CHATTERTON: Mr. Chairman, Mr. Commissioner, in view of this much stronger position of Judge Litt than what you anticipated yesterday, are you now possibily willing to give reconsideration in exchanging taxpayer's gas for

lobbying rights?

COMMISSIONER MARTIN: No, sir. We believe the contracts are still a viable and important alternative. This morning I made the comment after seeing the opinion that maybe those yesterday who leaned toward the Alcan route and wanted us to regard the decision as very, very crucial, and we said we think this decision is only a part of the process may now change and say this decision is determinative. We still think this decision is an important part but hardly determinative in the final outcome and that the contracts we're advancing may be possibly a little more important by virtue of it, rather than less.

REP. CHATTERTON: Thank you.

SENATOR RADER: Any further questions of the Commissioner? Senator Croft?

SENATOR CROFT: Commissioner, just so I understand it, because I heard your testimony yesterday, did I understand you to say that you testified yesterday that the unequivocal answer is "yes" that we can export those products after they are used in a pretrochemical facility? Because I understood you yesterday to say --

COMMISSIONER MARTIN: Apparently that was misunderstood and I talked to several people. Most people understood it the way I expressed it a second ago rather than your way, Senator Croft, but I wanted to clear it up today. There

is no question under the contract, in my view, that we have the right to take the gas off, to utilize it in Alaska for any purpose except liquefaction for export and then to export the products that are made therefrom.

SENATOR CROFT: And can we then export the LNG under the contract?

COMMISSIONER MARTIN: No, sir. If we take it --

SENATOR CROFT: Does it all have to be used in the state?

COMMISSIONER MARTIN: That's what I made clear yesterday. But we can liquefy gas so long as the LNG is being used in the state, so we even have the flexibility to go through liquefaction and then tanker that around and use it in other communities on the coast.

SENATOR CROFT: One final question. If -- and this didn't originate with me but somebody else asked me to ask it. If the primary purpose of these contracts is to gain additional support for the El Paso route, why did the state contract with El Paso to give them twenty-five percent of the Prudhoe Bay --

COMMISSIONER MARTIN: That is a very good question and I think the answer to it goes very much to the reason that these contracts are a little misleading in terms of totally construing them as pure political support. The fact is that El Paso can benefit just as much from telling its citizens that it has an opportunity to own gas pursuant

to its success as any other company. As it was before, El Paso was a sponsor of the gas line which was very much in the state's interest but without any ownership of gas and only a prospective chance of getting it. But under these contracts they too could say that they have an opportunity to supply gas to their constituents where they couldn't have said that before.

SENATOR RADER: Any further questions of the Commissioner? Mr. Swanson?

REP. SWANSON: Yes. If we lose both these battles, both the El Paso and the Alcan will you switch your support now to Arctic or Tenneco?

COMMISSIONER MARTIN: No, sir. The state's position, I think, on that by all its findings is very clear. We believe that the Arctic offers very little benefit to the state and would be a last choice. We have testified to that extensively in the FPC.

SENATOR RADER: Any further questions, Mr. Swanson? Mr. Gruening?

REP. GRUENING: Yesterday I think a questions was asked by Representative Meekins if a commitment of royalty gas prior to construction, let's say the petrochemical facility in Alaska would not be considered an in-state use. It's a commitment on an arrangement where the gas went out of the state but that was part of the contract

under which this construction --

COMMISSIONER MARTIN: Yes, sir. I responded to Mr. Meekins that that is the item that we have committed, the export of gas -- of surplus gas is the thing that we have sold under this contract and that kind of a negotiated deal would not be possible.

REP. GRUENING: Regardless of whether it was part of a contract to build a petrochemical facility?

COMMISSIONER MARTIN: That's right, because that gas would not be used in Alaska. It would be used as an enticement to come. That in fact is the sort of deal that Farmland International offered and it's one of the reasons why it was unacceptable.

SENATOR RADER: Representative Chatterton?

REP. CHATTERTON: Mr. Chairman, I'm sorry. Commissioner, in answer to a question that you gave here just a moment ago, I think I have got to ask you another question. You answered a question as to whether you would switch your support in any way, in any shape or form to the Arctic Gas proposal and you answered that "no", I believe.

COMMISSIONER MARTIN: Yes.

REP. CHATTERTON: So, in effect you're really saying -- or reconfirming that the only reason for these gas sales contracts are to gain or buy additional lobbying effort for one or two choices. There is no other advantage to

the contracts, is that right?

COMMISSIONER MARTIN: No. I think I made it clear yesterday in great detail that I thought there were several advantages to the contract of which that one may very well be the principal one. But the contracts would be, I think, valuable under any circumstances. I think Mr. Swanson's question, does the state intend to switch its support to Arctic in certain circumstances, my answer was "no". The present Arctic proposal would be of very little benefit to the state.

REP. CHATTERTON: Thank you, Commissioner.

SENATOR RADER: Senator Huber? Incidentally, I want to invite legislators in the audience to seat themselves at vacant places at the table if you desire, with the understanding that if committee members come in that you will relinquish your seat to them. But if you wish to participate, it's a little bit easier and more convenient, you are certainly welcome. There are two seats here and there is one over here to take advantage of that. Senator Huber?

SENATOR HUBER: Mr. Chairman, Commissioner, I want to clear up something that looked like, from press reports and so forth last night, it kind of sounded like from the meeting the amendment that was gotten in Congress by our delegation to allow us to withdraw our gas, it seemed like the testimony was such to make one believe that we had no

choice other than that and I think that's what is causing part of the confusion about the Arctic Gas. And would you reaffirm if we never --

COMMISSIONER MARTIN: Oh, I understand.

SENATOR HUBER: If we never commit our gas, say the Arctic route is chosen and the State of Alaska never commits any of its gas thereby not allowing any of it to flow -- to start flowing to the South 48, that it is still our gas under current laws in Congress -- previous laws or current laws, we can't have it confiscated on us until --

COMMISSIONER MARTIN: I understand the question now, Senator. I think that is a good question if that is the way you are going. I think that the committee could very well conclude, based on the utilization of Section 13(b) or the theory that Mr. Moody advanced last year, that there might be enough benefits in these contracts to consider going ahead with them or something very much like them under any circumstances. But, as I understood Mr. Swanson's question, he asked if we would switch our support to Arctic and I took it in terms of just an evaluation of the route, my answer would be "no". But yes, I think that it would be a legitimate consideration, given the other benefits of this contract, to at least consider utilizing either the contracts or the format to try to gain the same kinds of protection.

I might add that Judge Litt's decision is apparently going to be very sobering in that regard because he specifically recommends the repeal of 13(b) and makes it plenty clear that as far as he is concerned, unless there is something like that, the FPC will have no intention whatever of approving any state off take. It's a decision highly influenced by strong national interest.

SENATOR HUBER: And, Mr. Chairman, even if 13(b) is repealed, the State of Alaska if it wants to ever use any of this gas, the only choice we would have would be never to commit it in the first place thereby depriving the people of the Southern 48 states of having any portion of it because there is no law that says they can confiscate our gas.

COMMISSIONER MARTIN: Well, Senator, that's not the only alternative we would have because as you know, the terms of this contract provide that should the arrangement for off take not be approved by the federal government, the contracts fail. In other words, we are then back to ground zero and have whatever alternatives we might have minus the loss of time which is inherent in attempting to get that approval.

SENATOR HUBER: I wanted it clear that the FPC can't just assert our royalty share of gas. It requires us to have

committed it in the first place and allowed it to flow before they can assert it even without 13(b)?

COMMISSIONER MARTIN: Yes, but not through the contract. It means allowing it to flow, it is different from committing it. It is the first flow of the gas which we believe is the most substantial problem. And so, in the event that these contracts were approved, but not subsequently approved to the federal level in terms of the off-take provisions, we would then be back in the situation where we would have to act before the gas first started to flow to look at our other alternatives. The other alternatives being in-state pipelines or other alternatives.

SENATOR HUBER: That's why it would seem that the judge's strong decision for Arctic Gas, as he made it, didn't take into consideration the fact that if he allows Alaska no use of their gas and you may very well get to the point where Alaska says "you don't get our gas then." We certainly haven't taken that stance.

COMMISSIONER MARTIN: We haven't taken that position. We think that is not a good position to take in the national decision process at this time, Senator Huber, although I can understand your sentiment in perhaps wanting to get there. We have not taken that tack, attempting to carve out a way to utilize the gas on a cooperative way rather than doing it through confrontation.

SENATOR HUBER: That is why I'm disappointed in his determination.

COMMISSIONER MARTIN: He incidentally has searched, as you'll see from the release and then later from the decision, substantial state jurisdiction, including the ability for the FPC to allocate and take the gas. So I think that while this doesn't speak to the FPC or to the federal decision making process, there are a number of things of great concern to the state in this contract -- or in this decision.

SENATOR HUBER: Thank you, Mr. Commissioner.

SENATOR RADER: Any further questions?

REP. CHATTERTON: Yes, Mr. Chairman.

SENATOR RADER: Mr. Chatterton?

REP. CHATTERTON: Mr. Commissioner, if we initially take our royalty gas in value instead of in-kind, do we keep all options open for intrastate usage?

COMMISSIONER MARTIN: Mr. Chatterton, rather than whether it is taken in value or kind, the point you must operate from is the point that gas first flows through the pipeline and if at the time it first flows through the pipeline and is merged in the interstate stream, we are allowing our gas to flow without any arrangement to take it off -- any approved federal arrangement to take it off. That is the risk of loss of the gas,if at that time we

have not taken in-kind and protected it, then the problem would attach.

SENATOR RADER: Mr. Parr?

REP. PARR: Mr. Commissioner, in this press release on page four, the second paragraph, Judge Litt finds that "The Commission clearly has full jurisdiction over producer wellhead sales in interstate commerce, transport of the gas within Alaska, and transport and sale within the lower 48 states". Now at that second clause, does that mean in the judge's opinion that if we built our own pipeline, let's say from Prudhoe Bay to Anchorage, that the FPC would still have jurisdiction?

COMMISSIONER MARTIN: Yes, sir.

REP. PARR: Even if it never got into the interstate pipeline? Intrastate pipelines are not regulated by the FPC.

COMMISSIONER MARTIN: We're giving you the present state of the law. The judge is apparently making a somewhat extended statement regarding it.

REP. PARR: Under existing law, as far as you know, intrastate pipelines are not regulated by FPC?

COMMISSIONER MARTIN: Yes.

REP. PARR: Is that correct?

COMMISSIONER MARTIN: That's right.

REP. PARR: And so what the judge is doing is either trying to change it by his statement or interpreting it different

than you?

COMMISSIONER MARTIN: He has made a number of very extreme statements, obviously taking a very strong position in the case, Mr. Parr.

REP. PARR: Thank you.

SENATOR RADER: Any further questions of the Commissioner? Thank you very much, Commissioner.

COMMISSIONER MARTIN: Thank you for your courtesy. I thought it would be helpful, Mr. Chairman.

SENATOR RADER: We appreciate it.

COMMISSIONER MARTIN: We will give you additional copies of this today as they come in that are out of the decision. Those are just miscellaneous pages.

SENATOR RADER: Well, I think that we will probably rely upon your analysis of this tomorrow rather than our hour by hour report here.

COMMISSIONER MARTIN: Those are all out of context.

AGO 546520

SCOMM

#16:3

PUC Regulation Inevitable

Oil Daily Mon Aug 29, 1977

By BILL GREGG

CALIFORNIA Public Utilities Commission regulation of most intrastate crude oil and petroleum product pipelines now appears inevitable.

The PUC, for the past two years, has been conducting a non-publicized investigation into the operations of crude and product lines in California owned by Atlantic Richfield, Exxon, Gulf Oil, Mobil Oil, Shell Oil, Superior Oil, Chevron USA, Texaco and Union Oil Co. of California.

The purpose of the investigation has been to determine whether the pipelines should be classified as common carriers and as such regulated by the state agency.

Undeterred by the fact that only last year the state Senate Public Utilties Committee rejected (by an 8 to 0 vote) lower house bill authored by Assemblyman Terry Goggin (D.-San Bernardino) which would have classified all privately owned oil pipelines in the state as common carriers, the PUC continued it probe.

Then, last week, it was disclosed that Arco had negotiated a settlement with the PUC staff which is subject to commission approval.

UNDER TERMS of the tentative settlement Arco would submit most of its pipelines to PUC jurisdiction and transfer all these assets to a subsidiary which would then file tariffs with the commission.

The proposed rate base (approximately $9.5 million) would result in widely varying rates, ranging in the case of crude lines as low as 2 cents per barrel for very short hauls, to as high as 41 cents a barrel for shipments from Cuyama station to Los Angeles basin refiners (approximately 150 miles).

All of Arco's 23 major trunk lines are included in the proposed deal.

The PUC is currently inviting reactions of shippers—especially independent producers and refiners—to the terms of the tentative settlement with Arco. Specific details have been supplied to many and are available to others on request.

The commission staff urges that the response of these shippers be sent early enough (at least by Sept. 21) to allow time for analysis.

The PUC, incidentally, dismissed Exxon from its proceedings upon discovering early in the investigation that the company operates only a 3.4-mile crude line—a "stub" line to take deliveries from a Getty Oil Petroleum line to Connenecia refinery in northern California.

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COMPROMISE legislation relating to the siting of liquefied natural gas marine terminals and processing plants (heavily revised S.B. 1081) sailed through the California lower house Resources, Land Use and Energy Committee with a 10 to 2 vote and is expected to be approved by the Assembly's Ways and Means Committee this week.

There even some who privately predict the measure will be approved by the lower house and sent to the Senate before the end of the week.

After all, the compromise was hammered out earlier this month (Aug. 15 Oil Daily, p. 8) at a four-hour conference between key state solons, gas companies, and organized labor and is known to have Gov. Edmund G. Brown Jr.'s approval.

IN ITS revised form S.B. 1081 states that the first LNG terminal and processing plant can only handle LNG now under contract from Indonesia and south Alaska; that it must be located in an area where the population density within one mile of the site may not exceed 10 persons per square mile; that beyond this there must be a four-mile zone with a population density not more than 60 persons per square mile. The state Public Utilities Commission is named the lead government siting agency and its decision could be appealed only to the state Supreme Court.

In Los Angeles, Keith McKinney, president of Western LNG Terminal Associates, which will build and operate the facilities, said he was "encouraged" by the assembly committee's action.

As this column noted earlier this month, enactment of the compromise legislation makes it probable that the state's first LNG marine terminal and processing plant will be located at Point Conception.

If S.B. 1031 clears both legislative houses by Sept. 15, and there seems little doubt that it will, and is then signed by the governor who has made his approval of the revised measure abundantly clear, it will become effective Jan. 1, 1978.

Oceaneering Settles Suit Over Submersible

HOUSTON—An injunction hearing concerning the WASP, a one-man submersible with articulating arms, has been settled out of court, Oceaneering International Inc. announced.

The action was brought by Oceaneering and two U.K. affiliates, D.H.B. Construction Ltd. and U.M.E.L. Ltd., to stop Graham Hawkes from selling ideas that had been developed while Hawkes worked for D.H.B. Hawkes formed Osel Offshore Submersibles Ltd. to develop and market the WASP for underwater exploration.

The terms of the settlement require Osel to sell WASP units exclusively to Oceaneering for the next several years. Other firms desiring to use WASP will buy it from Oceaneering.

The WASP unit, designed for midwater work, complements the JIM suit which is used for work on the sea bottom at depths up to 1,000 feet. The WASP offers the diver mobility at midwater by a rotary engine.

CORRES.

M E M O R A N D U M

April 27, 1977

SUBJECT: Policy Considerations in North Cook Inlet Royalty Gas Sale (W.O. #4105, Supplemental)

TO: The Honorable John Rader

FROM: Gregg K. Erickson
Director of Research

Summary

As you requested, we have provided you, in the form of Ms. Kallab's memorandum of April 26, a review of the history and issues raised by the proposed North Cook Inlet royalty gas sale. After review of Ms. Kallab's findings (in which we concur), we believe that approval of this contract will tend to create far-reaching precedents with respect to the terms and conditions under which the state may make royalty gas available for in-state use, both elsewhere in the Cook Inlet field and in the northern part of the state. In addition, we believe that a brief technical analysis of the charges established by Phillips for transportation of the state's royalty gas is in order.

Precedents That Would Be Established By The Proposed Sale

As a matter of public policy, there will be no regulatory review of the transportation costs charged against royalty gas. In general, it makes no economic or technical sense to have a multiplicity of oil or gas pipelines running from point A to point B. Because of the fact that the efficiency of pipeline transportation increases very rapidly as one goes from smaller to larger pipelines, it minimizes the real economic costs of transportation to have a single line of the largest possible diameter. The owner of such a line has a monopoly, but it is a "natural monopoly" in the same sense that an electrical distribution or telephone system is a natural monopoly, i.e., to have more than one system would simply raise costs to the consumer. In the absence of regulatory restraint, however, the natural monopolist will have every incentive to charge "what the market will bear". Ratification of the current proposal may establish an important precedent with respect to the means by which

charges are assessed against gas taken in kind for in-state use elsewhere in Alaska. We may reasonably expect to see many other situations in the future where industrial facilities are served by private carrier lines similar to the Phillips line in Cook Inlet. Use of these lines may be the only reasonable way for the state to bring its royalty gas to local markets. Ratification of the current contract would tend to establish the precedent that the owners of these lines should be permitted to charge for the transportation of the state's royalty gas on the basis of what the market will bear rather than on the basis of the cost to them of providing the transportation service.

Whenever the state takes its royalty gas (or oil) it will be obligated to bear the cost of increasing production by the amount necessary to maintain the original flow level. In the instant case, these costs are the 10¢ per Mcf which would be charged by Phillips to cover their costs of additional compression facilities.

The legislature (and the Alaska Public Utilities Commission) will acquiesce in an arrangement which proposes the construction of a $4 million gas transmission facility which is, by any standard of technical and economic efficiency, totally unnecessary. Because of the lack of regulatory jurisdiction or the unwillingness of Alaska Pipeline Company (APC) and the Alaska Public Utilities Commission (APUC) to pursue regulatory solutions which may be available under existing law, APC has not been able to negotiate an exchange agreement with Union-Marathon (U-M) which would, as Ms. Kallab's memorandum points out, make the $4 million "royalty gas line" unnecessary. Although the negotiation of such an agreement would not appear to increase costs to U-M by one iota (they may even reduce them) there are commercial advantages to U-M in refusing to negotiate, since blocking such an agreement limits the alternative supply options of Alaska Pipeline Company and thus enhances the value of U-M's gas reserves in the Kenai field. Of course, Phillips has its own reasons for not wishing to enter into such an agreement; i.e., to retain the royalty gas share.

By ratifying this agreement the legislature (and the APUC) encourage the cross subsidization of one group of rate payers by another group. The commission has, as noted in Ms. Kallab's memorandum, stated that the higher costs of royalty gas shall be allocated proportionately among all rate payers served by Alaska Pipeline Company. Until and unless the proposed royalty gas line is built (or an exchange agreement is developed) this will result in those rate payers located in the North Kenai Road Service Area (who consume the relatively high cost gas) being subsidized by the rate payers elsewhere in APC's system. If, as expected, the wellhead price of gas in Cook Inlet rises, it will almost certainly result in the Bernice Lake power plant paying less for its gas than Alaska Pipeline Company is paying for it. Apart from the questions of

fairness involved, this is certainly an invitation to a rate-payer action in which it would be asserted that the rates charged by APC are noncompensatory and thus not "just and reasonable" as required under existing law.

Technical Considerations With Respect to the Proposed Rates

As Ms. Kallab has pointed out, Phillips has asserted that the 5.5¢/Mcf deduction used in calculating the wellhead value of natural gas for royalty and severance tax purposes is "not appropriate" for the calculation of transportation charges against royalty gas taken in kind. We are not aware of any rationalization of this statement. It seems fairly clear, however, that the difference between this figure and the 20¢/Mcf (escalating at 6%) which they propose to charge is greater than can be justified by any rationale we can conceive. It is possible that neither figure represents a fair and reasonable transportation cost, but it is impossible that both can simultaneously be "fair and reasonable" in the context of the purposes for which they are being used.

We do not assert that we can establish or even estimate what would be a "fair and reasonable" charge for transporting the royalty gas ashore, but we do concur with the sentiments expressed by Dr. Dave Knudson, petroleum economist with the Department of Revenue, who (writing as a private citizen) states that he can find "no justification that a pipeline costing $10 to $12 million perhaps nine years ago (which is most probably highly depreciated) should have a cost of service of 10¢ per Mcf". Mr. Knudson's letter, dated April 6, 1977, is a part of the royalty board's official file on this matter, and a copy of it is attached for your convenience. Although we believe fair and reasonable charges in this instance can only be determined by an appropriate regulatory proceeding, we do categorically assert that the calculations contained in "Table I" do not conform to any of the possible rate-making methodologies that are used by regulatory commissions in the United States.

GKE:jm
Attachment

STATE OF ALASKA
THE LEGISLATURE

LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

MEMORANDUM April 26, 1977

SUBJECT: North Cook Inlet Royalty Gas Sale (W.O. 4105)

TO: The Honorable John Rader

FROM: Elke Kallab
Research Analyst

This is in response to your request to look into matters relating to the proposed sale of state royalty gas from the North Cook Inlet gas field to Alaska Pipeline Company. You were particularly concerned with the gathering and compression charges Phillips Petroleum Company, the operator of the North Cook Inlet gas field, is planning to assess Alaska Pipeline Company for producing and transporting the royalty gas to Alaska Pipeline Company, and the question of whether Phillips Petroleum Company would come under the jurisdiction of the Alaska Public Utilities Commission or the Alaska Pipeline Commission as a result of transporting gas for Alaska Pipeline Company.

Summary

It would appear from the available records and all the information we have obtained that the added gathering and compression charges, negotiated between Phillips Petroleum Company and Alaska Pipeline Company will be allowed to be flowed through by virtue of Order No. 3, Docket U-75-68 issued by the Alaska Public Utilities Commission December 17, 1975, unless the APUC can be convinced to reopen the case in order to determine if the added charges are "reasonable and just". Furthermore, the Attorney General's office has issued legal opinions which exempt Phillips Petroleum Company from Alaska Public Utilities Commission or Alaska Pipeline Commission jurisdiction, since contracts, which have been submitted to the Legislature for approval, propose that Phillips Petroleum Company transport the royalty gas from the platform to a delivery point onshore for the State with Alaska Pipeline Company taking delivery onshore from the State and reimbursing the State for any costs incurred.

However, we believe sufficient grounds exist to question some of the propositions or assumptions which have been put forward to advance the argument that the royalty gas sale as presently proposed is in the best interests of the State and the public.

We submit the following information to provide you with an abbreviated history of what has transpired to date regarding the sale of royalty gas from the North Cook Inlet gas field to Alaska Pipeline Company, as well as to discuss in some detail the various issues which are involved in this matter.

After you have had an opportunity to read this memorandum, we would appreciate receiving your comments and instructions as to how you wish us to proceed. We would be happy to expand on any point or matter, or answer any questions you may have.

EK:mo
Enclosures

ATTACHMENT TO MEMORANDUM OF APRIL 26, 1977
CONCERNING NORTH COOK INLET ROYALTY GAS SALE

Background

In August of 1975 Alaska Pipeline Company (APC) first approached the State to purchase the State's royalty gas from the North Cook Inlet gas field. APC needs additional supplies of gas to assure continued service for its North Kenai Road customers, which includes the Bernice Lake power plant as the main customer, and some 285 other small customers. These customers are presently being supplied by gas APC has contracted for with Union-Marathon (U-M) from the Kenai gas field.* The original contract was for ten years, expiring April 30, 1977, for a total of 10 Bcf of gas. Due to unexpected heavy usage, APC used up its committed supply in August 1976. The contract has been extended by U-M using "Anchorage" reserves from a second contract APC has with Union-Marathon for gas from the Kenai field.

In addition to the immediate need to replace the exhausted gas supply on the North Kenai Road, APC also needs to build up its diminishing dedicated gas reserves, particularly in the Anchorage area. (The need for added dedicated reserves was apparently the major consideration for allowing flow through of higher priced royalty gas in APUC's Order No. 3, according to former Commissioner Richard D. Edwards, who heard the case.)

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* *A map showing location of the gas fields, pipelines and other pertinent information relating to this memorandum is enclosed for ready reference.*

The North Cook Inlet royalty gas for which APC made an offer is now being used by Phillips Petroleum Company, the producer/operator of the North Cook Inlet gas field, to meet 70 percent of its contractual requirements with Tokyo Gas and Tokyo Electric.

APC offered to pay the State the same price as the State is receiving from Phillips for royalty gas taken in value by the State from the North Cook Inlet field. At the time APC assumed this price to be 45¢/Mcf at the wellhead and 5.55¢/Mcf for transportation from the platform to Phillips' Kenai LNG plant. However, as discussions continued, it became quite clear that Phillips did not accept the 5.55¢/Mcf figure as an appropriate transportation cost. They indicated that the 5.55¢/Mcf charge was ". . . worked out and used as a deduction for computing wellhead value of the gas for purposes of paying royalty and taxes . . ." and that it was not the appropriate place differential for the kind of arrangement APC was contemplating.[1] As a result APC and Phillips entered into negotiations to arrive at a mutually agreeable charge for gathering and added compression costs. By negotiation the charges were agreed to be 10¢/Mcf for dehydration and delivery of the royalty gas to shore, and a 10¢/Mcf charge for added compression facilities required to deliver the State's royalty gas in-kind, to be increased by mutual agreement as further compression facilities were needed to maintain production. Table I and II, enclosed, were supplied by Phillips Petroleum Company at the request of the Alaska Royalty Oil and Gas

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[1] *Letter from Phillips Petroleum Company to Alaska Gas and Service Company, dated January 9, 1976.*

Development Advisory Board to "justify" the added gathering and compression charges.

The royalty gas which APC hopes to buy from the State is more expensive than gas APC receives and has under contract from other sources. APC expected that the Alaska Public Utilities Commission (APUC) would allow them to flow through the added costs entailed in purchasing the royalty gas, which then were thought to be 50.45¢/Mcf at the Kenai LNG plant gate, and also that the APUC would allow APC to "commingle" the higher priced royalty gas with lower priced gas APC purchases from other suppliers. (Apparently "commingling" is used by the parties involved to mean what is usually referred to as "rolled in" or average cost pricing).

The APUC did in fact permit the commingling of the higher priced royalty gas with lower priced gas available to APC in their Order No. 3, Docket U-75-68 issued December 17, 1975. The order provides that the differing costs would be averaged on a monthly basis to insure a "proper" price to consumers, since the North Cook Inlet royalty gas is available only as produced by Phillips in meeting their own needs, and thus a predictable and fixed daily volume cannot be assured. The APUC estimated that the commingling of royalty gas with lower priced gas would increase the costs to customers between 2¢-5¢/Mcf per month.

In addition, the APUC allowed APC to flow through the costs of royalty gas purchases from the North Cook Inlet gas field. In doing so they did

* Conversation with Bill Hickman 4/14/77

not mention any cost figures on which the flow through provision was allowed.

(The royalty clause in the commission's December 1975 order states that it was imperative for APC to build up its reserves. However, it also provided that if the royalty clause was not used to reflect an average cost of gas on or before August 1, 1976, the APUC would commence an investigation to determine the reasons for the non-use and to determine whether the royalty clause should be deleted from APC's tariff. APC did provide the APUC with information why they could not take delivery of the North Cook Inlet royalty gas. There is no indication that the APUC took any action as a result of this.)[2]

APC also proposed to build a "royalty" pipeline from the onshore delivery point to its Anchorage line, a distance of approximately 30 miles and at a cost of approximately $4,000,000, to absorb the excess gas over and above that required to meet the North Kenai Road demands, thereby hoping to reduce the rate at which the reserves dedicated to Anchorage in the Kenai field would decline. However, APC stressed that an "exchange" of gas using Union-Marathon's transmission line from the Kenai gas field to the North Kenai Road would be preferable to a literal transfer of excess North Cook Inlet royalty gas since such an "exchange" would reduce the need to construct the "royalty" line. Such an "exchange" agreement has not been worked out between the parties which would be affected.

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2 *Letter from Alaska Gas and Service Company to Alaska Public Utilities Commission, dated September 29, 1976.*

AGO 801211

Around December of 1975, Homer Electric Association (HEA) too made application for the North Cook Inlet royalty gas to provide electricity on the Kenai Peninsula. Much of the available royalty gas from the North Cook Inlet gas field would be used to supply the Bernice Lake power plant on the North Kenai Road, which HEA hopes to acquire from Chugach Electric Association, and which is now being supplied by APC with gas from the Kenai gas field. Additional generating facilities HEA is planning to construct would use up the remaining available royalty gas from the North Cook Inlet gas field. On March 30, 1976 HEA withdrew its application for the North Cook Inlet royalty gas since it had found another reliable supply source for its new generating facilities, and APC had assured HEA that they would supply the Bernice Lake power plant with gas.

Contract 76-1, selling the State's royalty gas from the North Cook Inlet gas field to APC, was executed June 4, 1976 and approved by the Legislature May 20, 1976. The records show that the House passed SCR 106 on voice vote, and the resolution passed the Senate 17-2. The major provisions of this contract were--

Quantity:	All royalty gas available from the North Cook Inlet gas field.
Delivery Point:	The wellhead. Phillips' platform.
Price:	55.5¢/Mcf to July 1, 1977 with subsequent annual price escalations based on the highest of three pricing alternatives.
Expiration Date:	July 1, 1984, the same time Phillips' contract with Tokyo Gas and Tokyo Electric expires.

Appendix "A", enclosed, sets out the key provisions of this contract together with those currently before the Legislature.

APC discovered that they could not take delivery of the gas under Contract 76-1 for a number of reasons, the most significant of which was that APC would have to take delivery of the gas at the platform, which would subject Phillips to regulatory jurisdiction of the APUC or Alaska Pipeline Commission as a utility. Phillips refuses to be subject to any regulatory jurisdiction. Their refusal to be regulated dates back to the very beginning of the negotiations when the State was first approached by APC to take its royalty gas in-kind rather than value, and has always presented a potential risk to the successful completion of negotiations. An attempt to exempt Phillips from regulatory jurisdiction by the APUC or Alaska Pipeline Commission by way of a waiver proved impossible since to do so Phillips would have had first to submit to the jursidiction of the APUC or the Alaska Pipeline Commission to be granted the waiver, a condition unacceptable to Phillips.

Another difficulty arose as the result of APC not being able to take all of the royalty gas available as provided for in Contract 76-1. The average daily royalty gas production from the North Cook Inlet field amounts to between 15-17 MMcf based on previous years' production. APC's estimated average daily needs to service their North Kenai Road customers is approximately 8 MMcf. Since APC has not constructed a

"royalty" pipeline from the delivery point on the North Kenai Road to their "Anchorage" line, and since they have not been able to work out an "exchange" agreement with Union-Marathon, APC is unable to utilize the excess amount of gas. The contract does not allow APC to resell the excess royalty gas to Phillips (although Phillips was agreeable to such an arrangement) since this would violate the contract provision which required that all of the royalty gas sold to APC be used within the State. Since Phillips exports its gas to Japan, selling any excess royalty gas back to Phillips would be in violation of Contract 76-1.

In conjunction with the excess volume which would have been used if a "royalty" pipeline had been in existence, APC told the APUC in September of 1976 that the short life of the contract (July 1, 1984) was one of the reasons for them not constructing a connecting line. Such a line would have allowed for APC to slow the decline of reserves dedicated to Anchorage, the main reason the APUC allowed the flow through tariff for royalty gas. In addition, such a line would also assure a stand-by gas supply for North Kenai Road customers in case production or supply from the North Cook Inlet field were to be interrupted for any reason.

By the end of January, 1977 APC petitioned the State to "re-draft" Contract 76-1 in order to make the contract operational.

To accomplish this it was suggested that the State have the royalty gas transported to shore thus avoiding APUC jurisdiction over Phillips' pipeline, since the State is not a utility. APC would take delivery at

or near the Kenai LNG plant and reimburse the State for any costs incurred. A legal opinion from the Attorney General's office was secured, at the insistence of Phillips, which holds that Phillips is not a utility subject to APUC jursidiction. Another legal opinion was issued exempting Phillips' pipeline from Alaska Pipeline Commission jursidiction on the basis that the pipeline is not used as a common carrier by Phillips, and that it is not subject to the common carrier provision of the current law, since the pipeline was constructed prior to the enactment of that law. (Exemption of Phillips' pipeline from APUC jursidiction had been supported by the Alaska Royalty Oil and Gas Development Advisory Board as early as December 1975 to facilitate the sale of royalty gas to APC.)

It was further suggested that APC would be required to take only such amounts of royalty gas as they had need for. Any gas APC was unable to take delivery of as it became available was to be sold to Phillips as if the State had continued to take its royalty gas in value.

These changes and other provisions were incorporated into agreements between Phillips and the State, and APC and the State. The contract between APC and the State is now awaiting legislative approval, with the agreement between Phillips and the State having been submitted to the Legislature as an exhibit to the APC contract. The key provisions of the two agreements are listed in Appendix "A", which is enclosed.

Issues

Gathering, Compression and other Charges or Costs

The amount charged APC by Phillips for dehydration and transportation is 10¢/Mcf. The amount charged APC by Phillips to add a compression unit to maintain capacity in the gathering system is set at 10¢/Mcf. (The agreement between Phillips and the State, and the contract between APC and the State provide that APC will make all payments for the State's account directly to Phillips.) Both of these charges increase at a compounded rate of 6 percent per year. As further compression facilities are installed in the future, additional charges are to be mutually agreed upon by the parties involved. In addition, APC must pay Phillips in proportion to its deliveries for any new or increased taxes and charges which are levied against Phillips with respect to the gathering of royalty gas.

Phillips has supplied data on the gathering and compression charges negotiated between themselves and APC for delivering the State's royalty gas. (See Table I and Table II enclosed.) These figures have not been scrutinized as to whether they are just and reasonable by the Alaska Royalty Oil and Gas Development Advisory Board or the APUC. However, it has been suggested that they are on the high side.

Perhaps one way to get a better handle on these charges would be to request the APUC to review the royalty gas clause of its December 1975 order as it applies to allowing flow through charges. At the time the

flow through provision was granted the transportation cost figures were thought to be considerably less than those proposed now. It is questionable whether the APUC would have allowed the currently proposed flow through charges, considering their comment in the order that the flow through provisions proposed by Alaska Gas and Service Company (AGAS), the distribution affiliate of APC, were ". . . so broad that nearly all increases in any . . . cost of purchased gas could be flowed through."[3] This tends to raise some doubts concerning APC's assertion that the APUC had intended to allow any and all flow through costs. The APUC order also states that the cost of royalty gas will be "somewhat higher" than the price of gas from other gas supplies now committed to APC. Other supplies are priced at 41.5¢/Mcf for gas from the Kenai gas field, compared to 84.65¢/Mcf for royalty gas from the North Cook Inlet field, i.e., 104% higher.

It is of particular interest to note that one of the reasons the APUC allowed the added costs was to provide APC with the opportunity to obtain additional gas to supplement their dwindling reserves, particularly in the Anchorage area. Since the "royalty" line to move North Cook Inlet gas to Anchorage has not been built, and APC is not required under the contract to deliver gas to Anchorage, the question arises as to whether the added flow through charges should be allowed by the APUC. It is difficult to ascertain from the written material we have reviewed how hard APC negotiated with Phillips for less than the agreed to

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[3] *Alaska Public Utilities Commission Docket U-75-68, Order No. 3, dated December 17, 1975, page 7.*

charges of 10¢/Mcf for transportation and 10¢/Mcf for compression. Records show that APC discouraged the APUC from developing " . . . 'a complete record' of the negotiations (between APC and Phillips) for the Commission's files . . ."[4]. The question arises as to what incentives, if any, existed for APC to negotiate for lower charges if APC assumes that any added costs can be passed on automatically to the consumer under U-75-68(3)?

The argument that the royalty gas from the North Cook Inlet gas field is cheaper, even with the added 20¢/Mcf cost for transportation and compression charged by Phillips, than any "new" gas available to APC in the Cook Inlet is debatable. APC cites a $1.45 price for similar gas in Cook Inlet being offered by Pacific Alaska LNG to support its contention. (We understand the above to be a "spot sale".) However, since the contract with APC provides that the State will receive the highest of three pricing options on the annual anniversary of the contract, one of which is the highest price paid within a 100 km radius from the Phillips platform, and since we have been advised that the gas for which Pacific Alaska LNG is making an offer is within the 100 km radius, it is unlikely that APC can escape paying the $1.45 (or even a higher) price within the next year. Therefore, the assertion that regardless of the added transportation and compression costs the royalty gas is still a bargain is not quite accurate, and APC is not entirely candid when using this argument to attempt to convince the Alaska Oil and Gas Development

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[4] *Letter from Alaska Gas and Service Company to Alaska Public Utilities Commission, dated September 29, 1976.*

Advisory Board, the APUC or the Legislature " . . . that it appears royalty gas will always be available . . . at less cost than any other likely 'new' gas."[5]

At the same time APC told us that the above situation could not happen since no comparable sale to that provided for in the current contract would occur, and they, therefore, would never be subject to the pricing provision which calls for the highest price to be paid

> ". . . by any purchaser in the upper Cook Inlet area for gas of similar conditions of delivery; with due regard to appropriate factors including, but not limited to, differences of BTU content, delivery pressure, terms of the contract and connection charges." (Current Gas Purchase Contract, page 10, lines 3-8)

Royalty Line

One of the reasons APC cannot make Contract 76-1 of last year operational is that the contract provides that APC take all of the royalty gas available from the North Cook Inlet gas field. To have use for all royalty gas APC needs to ship approximately 50 percent to its Anchorage consumers, since only approximately 8 MMcf/day can be utilized on the North Kenai Road.

APC has been "flirting" with the idea of building a connecting "royalty" line from the North Kenai Road area to its "Anchorage" line, which delivers gas to Anchorage from the Kenai gas field from the beginning of the negotiations. However, they also have indicated that they would

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[5] *Letter from Alaska Pipeline Company to Alaska Oil and Gas Development Advisory Board, dated April 15, 1977.*

prefer to enter into an "exchange" agreement with U-M and Phillips to exchange royalty gas from North Cook Inlet with U-M gas from the Kenai gas field. This would be technically feasible, and cost far less than the proposed royalty line, since U-M runs a transmission line from the Kenai gas field to the North Kenai Road area, with APC running a line from the Kenai gas field to Anchorage. An exchange agreement would thus avoid a literal transfer of gas and eliminating construction of a "royalty" line. (See enclosed map.)

When APC found it impossible to work out an "exchange", they decided to build their own line to connect with the Anchorage line. However, this decision brought with it the request for all of the State's royalty gas from the North Cook Inlet field for the life of production rather than for a limited term through June of 1984. This request was not accepted by the State and Contract 76-1 provides for a termination date of July 1, 1984.

The question a to whether APC would build a royalty line continued and as late as February 2, 1977 APC informed the Alaska Oil and Gas Development Advisory Board that they would take such quantities of royalty gas as they could readily resell to their North Kenai Road customers, and not be committed to installing a pipeline connecting to their existing pipeline to Anchorage, although they could do so at their option.[6] The

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[6] *Letter from Alaska Pipeline Company to Alaska Oil and Gas Development Advisory Board, dated February 2, 1977.*

most recent indications are that APC is inclined to build the connecting line upon approval of the contract by the Legislature, since " . . . it appears that there is sufficient benefit from the royalty line to justify the investment by APC."[7]

The physical absence of the royalty line not only prevents APC from providing Anchorage with much needed dedicated reserves, which was the APUC's reason for the royalty clause which allowed flow through of costs and commingling of lower priced Kenai field gas with North Cook Inlet royalty gas, but it also prevents APC from providing North Kenai Road customers with stand-by gas should the royalty gas ever be insufficient to meet demand.

APC has indicated that a royalty line would not be feasible if the present contract were not approved this year, because the contract only extends to June 1, 1984. We do not find this argument very persuasive. APC fully expects to get the royalty gas from the North Cook Inlet gas field for the life of production once the contract has been signed. Furthermore, it should be noted that the new contract provides that the contract can be extended prior to its termination, a provision absent from Contract 76-1.

The Legislature may wish to consider extracting a firm commitment from APC that they will build a royalty line immediately, making it a con-

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[7] *Letter from Alaska Pipeline Company to Alaska Oil and Gas Development Advisory Board, dated April 15, 1977.*

dition of contract approval. If this can be accomplished, then APC should be required to take all of the royalty gas which becomes available after completion of the line, and the 3 Bcf "best reasonable effort" provision should be deleted from and/or revised in the APC contract as well as the agreement between the State and Phillips to avoid delays in deliveries once the line is operational.

Jurisdiction

Present indications are that there is no possibility for APUC or APC jurisdiction over Phillips' pipeline, in as much as Phillips operates and maintains the line for its own purposes. Phillips has not violated any laws, and both agreements provide that should Phillips come under either FPC, APUC or Alaska Pipeline Commission jurisdiction, the agreements terminate. Short of revoking their right-of-way permit and substituting a right-of-way lease, which may be possible but almost certainly would entail litigation, there appears to be no way to make them submit to regulatory jurisdiction.

To avoid future problems, the Legislature may provide that

1. All pipelines not currently covered by our common carrier statute agree to common carrier status retroactively to retain their pipeline right-of-way permits (Right-of-Way Leasing Act-38.35.120).

2. Sec. 43.06.630(9) of the Alaska Pipeline Commission Act be amended so that gas processing plants are covered in the definition of what constitutes a pipeline or pipeline facility, and deleting the reference to transportation as a common carrier.

3. The possibility should be explored if producers/operators of oil and gas fields located in remote or inaccessible locations, such as a platform, should be required to enter into mandatory exchange agreements with more favorably located fields or transmission lines, which are regulated by the APUC, to avoid jurisdiction, while at the same time protecting the public interest.

These suggestions have not been thoroughly investigated nor checked with the Division of Legal Services, but are offered as a beginning to remedy the current jurisdictional problems with which the State is faced as it affects Phillips' pipeline.

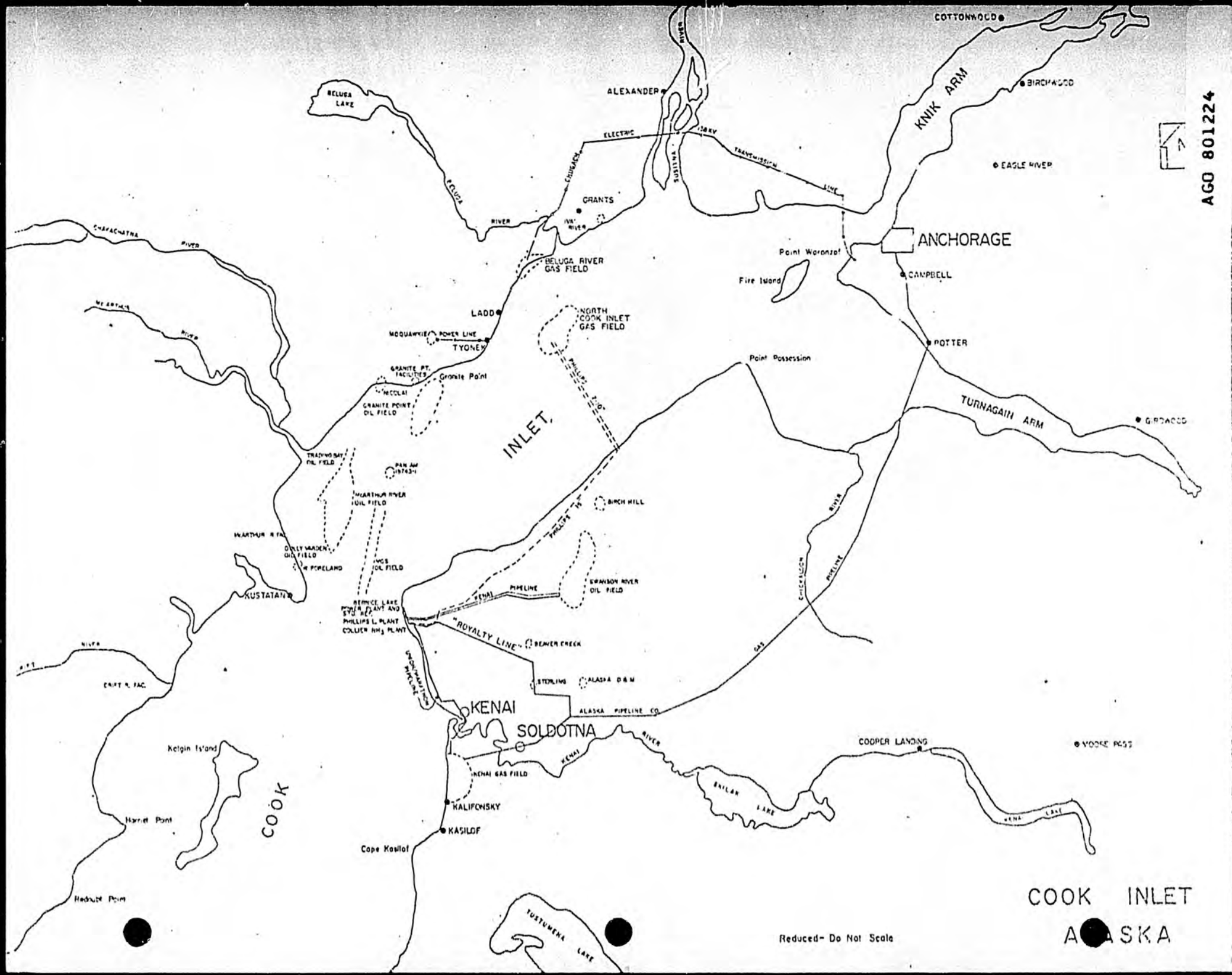
COTTONWOOD
BIRCHWOOD
KNIK ARM
EAGLE RIVER
ALEXANDER
BELUGA LAKE
ELECTRIC
TRANSMISSION
LINE
SUSITNA
CHUGACH
GRANTS
BELUGA
RIVER
CHAKACHATNA
RIVER
ANCHORAGE
Point Woronzof
Fire Island
CAMPBELL
BELUGA RIVER GAS FIELD
LADD
NORTH COOK INLET GAS FIELD
MOQUAWKIE POWER LINE
TYONEK
POTTER
Point Possession
GRANITE PT. FACILITIES
Granite Point
NICOLAI
GRANITE POINT OIL FIELD
INLET
TURNAGAIN ARM
TRADING BAY OIL FIELD
PAN AM
MCARTHUR RIVER OIL FIELD
BIRCH HILL
MCARTHUR R. FAC.
DOLLY VARDEN OIL FIELD
W. FORELAND
MGS OIL FIELD
KUSTATAN
SWANSON RIVER OIL FIELD
KENAI PIPELINE
BERNICE LAKE POWER PLANT AND STD. REF.
PHILLIPS L. PLANT
COLLIER NH3 PLANT
"ROYALTY LINE"
BEAVER CREEK
STERLING
ALASKA D & M
ALASKA PIPELINE CO.
CHICKALOON
GAS
PIPELINE
RIVER
KENAI
SOLDOTNA
KENAI GAS FIELD
KALIFONSKY
KASILOF
Cape Kasilof
Kalgin Island
COOK
Harriet Point
Redoubt Point
COOPER LANDING
MOOSE PASS
SKILAK LAKE
KENAI LAKE
TUSTUMENA LAKE
Reduced- Do Not Scale
COOK INLET
ALASKA

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TABLE I

PIPELINE

Estimated Present-Day Replacement Cost	at least	$25,000,000
Estimated Present-Day Replacement Cost Depreciated to 1977		17,300,000

ESTIMATED COSTS

	$/Year
Depreciation (20 Years)	$1,100,000
Rate of Return 15% on Depreciated Investment	1,520,000
Income Tax @ 52.9% (State & Federal)	1,700,000
Operating Expense	2,750,000
TOTAL	$7,070,000

Cost/Mcf @ 43 Bcf/Year = 16.4¢

Cost/Mcf @ 55 Bcf/Year = 12.9¢

TABLE II

COMPRESSORS
(FIRST UNIT)

To maintain capacity in the gathering system and compressors to handle the full 12.5% royalty gas volume, it will be necessary to install compressors at an earlier date. Also, it is estimated that to maintain this capacity it will be necessary to install an additional compressor unit over and above that required for maintaining deliveries without the State taking its royalty gas in kind. Estimated differential in compressor investment is $5,000,000.

Cost of Compression

	$/Year
Depreciation (10 Years)	$ 500,000
Rate of Return 15% on Average Investment	375,000
Income Taxes @ 52.9% (State & Federal)	420,000
Operating Expense	715,000
TOTAL	$2,010,000

Minimum Annual Payment	= $2,010,000
Royalty Gas Volume @ 43 Bcf/Year	= 5.4 Bcf
Royalty Gas Volume @ 55 Bcf/Year	= 6.9 Bcf
Cost/Mcf @ 5.4 Bcf	= 37.2¢
Cost/Mcf @ 6.9 Bcf	= 29.1¢

Phillips agreed with Alaska Pipeline Company's request to a compressor charge of 10¢/Mcf on a space-available basis and no minimum annual charge.

APPENDIX "A"

KEY PROVISIONS

	CONTRACT 76-1	PROPOSED REVISED CONTRACT CONTRACT BETWEEN STATE AND PHILLIPS (with APC being a signatory)	CONTRACT BETWEEN STATE AND APC
Quantity:	ARTICLE II All royalty gas available, when and as available.	ARTICLE IV 1. Phillips shall use its "best reasonable efforts" to deliver not less than 3 Bcf of royalty gas annually (without requiring installation or operation of added pipeline and compression facilities), and subject to a. availability of capacity in Phillips' facilities to handle volumes in excess of Phillips' own requirements; b. availability of royalty gas at the platform; c. APC's requirements; and d. APC's ability to take the requirements. 2. Over or under deliveries of royalty gas shall be carried in an over and short account. In the event the takes by the State (APC) shall ever be 60 MMcf less than the amount of royalty gas available, Phillips shall purchase the excess undelivered quantities of royalty gas over 60 MMcf from the State, and pay the State a price equal to that amount which Phillips would have otherwise paid the State had the State taken its royalty gas in value.	ARTICLE III 1. Up to all royalty gas available, subject to a. APC's ability to take the entire amount of royalty gas available on any given day; b. APC's need and available delivery facilities. APC shall use its "best reasonable efforts" to take not less than 3 Bcf of royalty gas annually. 2. Over or under deliveries of royalty gas shall be carried in an over and short account. In the event the takes by APC shall ever be 60 Mmcf less than the amount of royalty gas available APC is not permitted to make up for any such underdelivery and the State may sell the undelivered quantity of royalty gas to Phillips.
Delivery Point:	ARTICLE III Delivery point shall be the same for APC as it has been for State, which is Phillips' platform.	ARTICLE III & V Delivery point shall be at or near the existing pipeline tap being presently used to deliver gas from Phillips' pipeline to the Tesoro refinery, which is located in the general vicinity of Phillips' Kenai LNG plant on the North Kenai Road.	ARTICLE V APC's connection into Phillips' pipeline system at or near Phillips' pipeline tap serving the Tesoro refinery. It shall be the same delivery point as that of the State and Phillips.
Price:	ARTICLE V 1. To July 1, 1977 55.5¢/Mcf 2. July 1, 1977-July 1, 1978 the higher of a. 60.36¢/Mcf or b. price State would have received had it continued to take its royalty gas in value or c. the highest price paid by any purchaser in the Upper Cook Inlet area (within a 100 km radius of Phillips' platform) for similar quality gas and similar conditions of delivery. 3. July 1, 1978 and each succeeding 12 month period the higher of a. the previous year's price plus 2¢/Mcf or b. price State would have received had it continued to take its royalty gas in value or c. the highest price paid by any purchaser in the Upper Cook Inlet area (within a 100 km radius of Phillips' platform) for similar quality gas and similar conditions of delivery.		ARTICLE VI 1. To July 1, 1978 64.55¢/Mcf 2. July 1, 1978-July 1, 1979 the higher of a. 66.65¢/Mcf or b. price State would have received had it continued to take its royalty gas in value or c. the highest price paid by any purchaser in the Upper Cook Inlet area (within a 100 km radius of Phillips' platform) for similar quality gas and similar conditions of delivery. 3. July 1, 1979 and each succeeding 12 month period the higher of a. the previous year's price plus 2¢/Mcf or b. price State would have received had it continued to take its royalty gas in value or c. the highest price paid by any purchaser in the Upper Cook Inlet area (within a 100 km radius of Phillips' platform) for similar quality gas and similar conditions of delivery.

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	CONTRACT 76-1	CONTRACT BETWEEN STATE AND PHILLIPS	CONTRACT BETWEEN STATE AND APC
Gathering and Compression Charges and Taxes; Other Charges		ARTICLE IX 1. 10¢/Mcf for gathering costs to delivery point to increase 6 percent per year compounded annually on the anniversary date of the contract. 2. 10¢/Mcf for added compression costs to delivery point to increase 6 percent per year compounded annually on the anniversary date when the facilities were first used. 3. Additional compression charges to be mutually agreed upon between the parties, which includes APC since they are signatories of this contract (see also 12.3). If no agreement is reached within 90 days after Phillips serves notice about such added costs, then this contract is terminated. 4. Additionally, the State must pay Phillips any new or increased fee, imposts, duty, charge, excise or tax in proportion to the amount of royalty gas delivered to the State as it relates to gathering and compression.	ARTICLE VI & VII 1. 10¢/Mcf for gathering costs to delivery point to increase 6 percent per year compounded annually on the anniversary date of the contract. 2. 10¢/Mcf for added compression costs to delivery point to increase 6 percent per year compounded annually on the anniversary date when such compression facilities are ready for use. (This is different from State/Phillips agreement.) This does not obligate Phillips to install any compression facilities or to operate any compression facilities already installed. 3. Additional compression charges to be mutually agreed upon between the State and APC. If no agreement is reached within 90 days after the State serves notice about such added costs, then this contract is terminated (7.5). 4. APC must pay the State any amount for which the State is obligated to reimburse Phillips for a proportion of new or increased fees, imposts, duties, charges or taxes. (This leaves out excise.) (The language is somewhat different from State/Phillips contract, but the effect would seem to be the same.) 5. APC must pay the State any additional costs not covered in the contract and incurred by State in transporting the gas to shore.
Term:	ARTICLE VI Effective: Upon approval by the Legislature 5/20/76 Expiration: July 1, 1984	ARTICLE XIV Effective: Upon approval by the Legislature of the contract between the State and APC. Expiration: June 1, 1984 unless terminated or extended prior to that date.	ARTICLE VII Effective: Upon approval by the Legislature. Expiration: June 1, 1984 unless terminated or extended prior to that date.
Termination Clause:	ARTICLE VII Allows APC to terminate the contract within 30 days of written notice to State if APC is unable to make satisfactory arrangements to take delivery of the royalty gas. APC may not exercise this right after January 31, 1978.	ARTICLE IX, XI & XIV 1. Will be terminated immediately if deliveries to State (APC) have not commenced by June 30, 1978. 2. If subjected to regulation as a utility (11.2). 3. If added compression cost cannot be agreed upon within 90 days (9.3). 4. If contract between State and APC is terminated. 5. If terminated the State's election to receive its royalty gas in-kind is revoked, and royalty gas available shall be sold to Phillips in value. 6.	ARTICLE VII 1. Contract shall terminate immediately if deliveries to APC have not commenced by June 30, 1978. 2. Either State or APC may terminate this contract by giving 30 days notice to the other if Phillips comes under regulation as a utility. 3. Contract may be terminated if added compression cost cannot be agreed upon within 90 days. 4. Contract may be terminated if contract between State and Phillips is terminated. 5. 6. State may terminate upon 30 days notice to APC if the State cannot arrange for satisfactory transportation of royalty gas to shore.

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CONTRACT 76-1	CONTRACT BETWEEN STATE AND PHILLIPS	CONTRACT BETWEEN STATE AND APC
Representation and Condition Precedent:	ARTICLE XI Phillips, by entering into this contract, shall not be subject to regulation by the FPC, APUC or APC. Should they become subject to regulation as a utility this contract may be terminated by either party upon 30 days' notice.	ARTICLE VIII Neither this contract nor APC's use or disposition of the royalty gas will subject Phillips to FPC, APUC or APC regulation.
Payments:	ARTICLE XII APC to make all payments for State's account directly to Phillips.	
Miscellaneous		ARTICLE IX 1. Assignments of interest by APC may be made "...to conform with...(APC's) various financing documents or as may be desirable to...(APC) as to...(APC's) commonly owned affiliate or subsidiary." 2. If APC does not receive or purchase all royalty gas available, then State can dispose of that portion not taken, provided no gathering and compression charges are incurred by APC as a result.

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Prepared by:
Legislative Affairs Agency
Research Division
April - 1977

Background

Alaska Pipeline Company (APC) currently has a contract (dated May 1, 1967) with Union-Marathon (U-M) (often referred to as the "Nikiski" contract) for 10 Bcf of natural gas over a ten year period from the Kenai gas field. The contract expires May 1977. The contract has been "extended" to May 1978 "...(B)y using reserves out of...(APC's) Anchorage contract rather than new reserves...(APC has) been able to contract for...". (APC letter 3/22/76).

*APC states that due to heavy unexpected usage of the Bernice Lake power plant its reserves under the Nikiski contract could be used up prior to the expiration date (May 1, 1977).

I do not know if this in fact happened or not, and if it has what APC has done to meet the needs of its customers on the North Kenai Road, which besides the Bernice Lake power plant (which consumes 90 percent of the total daily volume) involves some 285 other customers on the North Kenai Road.

The Bernice Lake power plant is owned by Chugach Electric, but Homer Electric Association is in the process of acquiring it.

The heavy unexpected usage referred to above occurred during the repair period of the Knik Arm submarine cable from the Beluga power plant to Anchorage. The Beluga power plant is also owned by Chugach Electric.

Among others, the Bernice Lake power plant provides power generation to the Phillips-Marathon LNG plant and the Collier ammonia plant.

The Bernice Lake power plant can and used to burn oil, and could do so again if gas supply was interrupted, albeit at a higher cost since oil today is higher priced than gas.

*Informational material

In a letter, dated August 20, 1975, APC first applied/offered to purchase the State's royalty gas from the North Cook Inlet gas field (Phillips is the producer and operator of the North Cook Inlet field) in order to provide for a continuous supply of gas to their customers on the North Kenai Road.

*However, a draft memo by Bill Fackler then Deputy Commissioner of DNR to Guy Martin, Commissioner, dated November 19, 1975, states that the royalty gas from the North Cook Inlet gas field desired by APC was being sought more to add to their reserves than to assure a continuous supply for their North Kenai Road customers. This was based on the assumption that APC wanted 75 Bcf over a 15 year period, which far exceeded the approximately 8MMcf/day used on the North Kenai Road. In subsequent communication (12/12/75) the amounts of gas desired and/or required by APC were revised to include up to 50 Bcf to June 1, 1984 with up to 15MMcf/day; take or pay at 10MMcf/day. North Cook Inlet royalty gas production amounts to approximately 15MMcf/day. The North Kenai Road requirements are 8MM cf/day. It is assumed that the rest would be used to build up APC's reserves.

The most current arrangements call for APC to purchase up to 100 percent of the State's royalty gas available from Phillips but only such amounts as APC can readily re-sell. The remaining royalty gas would be re-sold to Phillips as if it were royalty gas taken in value. (Revised contract with 2/2/77 cover letter from APC).

It appears from the above that when APC found it in their interest they did indeed attempt to do both--replace the diminished reserves of the Nikiski contract, while at the same time augmenting their gas reserves.

In their letter application of August 20, 1975 APC offered to pay the State the same price it received from Phillips for its royalty gas from the North Cook Inlet gas field, which then was the highest value for gas received by the State. (I do

know price
not if this is still the case). This amounted to 45¢/Mcf at the wellhead. An additional 5.45¢/Mcf was charged for transportation from the platform to the LNG plant for a total price of 50.45¢/Mcf at the plant gate. The revised draft for a proposed North Cook Inlet royalty gas sales agreement, dated 12/12/75 indicates a wellhead price of 50.25¢/Mcf and a transportation cost of 5.55¢/Mcf for a total of 55.80¢/Mcf.

*Fackler's November 19, 1975 memo indicates a 5.55¢ transportation charge; Tom Williams, Director of Petroleum Revenue Divison uses a 5.5¢ charge according to Gregg Erickson (4/1/77); and APC correspondence of 12/12/75 shows a transportation charge of 5.55¢.

Phillips in a letter to APC, dated January 9, 1976, states that the 5.55¢/Mcf is not an appropriate "place differential"; that it "...is a number that has been worked out and used as a deduction for computing wellhead value of the gas for purposes of paying royalty and taxes...." and that it does not " "...represent...the appropriate differential for the arrangement...contemplate(d) ...." by APC.

The above compares to 41.5¢/Mcf and "deliverability" costs APC is paying to U-M for gas from the Kenai gas field. They did not disclose what the "deliverability" cost was, but Fackler's November 19, 1975 draft memo states that "(I)f price is similar to that of Anchorage contract gas, Bernice Lake indicated cost of 65.7¢ per MMBTU allows a healthy margin for ANG (same as APC) for the short distance involved." (The APUC would probably have the "deliverability" cost available).

Currently, the negotiated price between Phillips and APC is 10¢/Mcf for gathering costs, which includes dehydration, plus 10¢/Mcf for compression with the latter charge to be raised to 20¢/Mcf when Phillips has installed additional compression facilities to accommodate the State's in kind royalty gas production. Further necessary compression facilities which will need to be installed to maintain delivery

rates will be charged on a pro-rated basis. (I have no idea what happens to the royalty gas which would be "re-sold" to Phillips; i.e., the gas APC was unable to accept. Would it be charged the 10¢/Mcf for transportation and 10¢/Mcf (20¢/Mcf) for compression, or would it be "charged" the lower 5.55¢/Mcf presently in effect while Phillips takes our royalty gas in value)?

APC expected that the Alaska Public Utility Commission (APUC) would allow them to "flow through" the increased cost of the royalty gas purchased from the North Cook Inlet field, as well as to "blend" the higher priced royalty gas from the North Cook Inlet gas field with the lower priced gas they have contracted for from U-M. (Their letter of August 20, 1975). The commingling of North Cook Inlet royalty gas and Kenai field gas was approved by the APUC as was APC's request to flow through the increased cost of the North Cook Inlet royalty gas to APC customers (U-75-68 (3), dated 12/17/75). It was estimated by the APUC that the increased cost to customers would amount to between 2¢ and 5¢ per Mcf per month. (I don't know if this included the 10¢/Mcf/10¢/Mcf (20¢/Mcf) charges or the previously used 5.55¢/Mcf charge. It would probably make a difference in allowing them to flow through these higher costs. Need to get answer from APUC).

APC in a memorandum to Guy Martin, dated September 24, 1975 reconfirmed its intent to purchase North Cook Inlet royalty gas. In addition, APC indicated that a pipeline could be built from the Phillips-Marathon LNG plant to APC's Anchorage pipeline, a distance of approximately 30 miles, but that literal transfer was not necessary since existing interconnecting pipeline systems of Phillips and U-M could be used to move the gas by exchange and/or displacement (provided everyone concerned would be agreeable to such an arrangement. "Everybody" would be the State, APC and the producers involved--Union, Marathon and Phillips. Apparently APC never was able to work out an exchange agreement with Union, the operator of the

Kenai gas field and the gas transmission line on the North Kenai Road (12/7/75). As a result, APC planned to build a pipeline to tie in with their Anchorage line. (This brought with it the request for a commitment of all royalty gas for the life of production for the North Cook Inlet field rather than a term to June 1, 1984 as provided for). (Letters 12/12/75 and 2/3/76).

At this point APC will only take such quantities of North Cook Inlet royalty gas as it can readily re-sell to its North Kenai Road customers "...and thus not be committed to install a pipeline connecting to...(their) existing pipeline to Anchorage, although...(they) could do so at...(their) option." (Letter dated 2/2/77).

Since there is no exchange agreement, nor a connecting pipeline to their Anchorage line, APC will have to work out some means to provide for "standby gas" in the eventuality that royalty gas were not available. This could happen since APC has agreed to receive North Cook Inlet royalty gas from Phillips on a "space-available basis", which means when Phillips has surplus capacity in their gathering system and compressors. (This was part of the 10¢/Mcf (20¢/Mcf) provision negotiated between APC and Phillips).

If an exchange agreement could be worked out APC could receive royalty gas at its Kenai gas field connections. Such an arrangement would be advantageous to APC since it would minimize construction of a new pipeline as well as compression facilities APC might otherwise have to provide to avail itself to all the royalty gas they would contractually be entitled to.

APC's letter of September 30, 1975 reiterates that they wish to purchase the State's royalty gas from the North Cook Inlet gas field at or near the Phillips-

Marathon LNG plant on the North Kenai Road. In his November 19, 1975 draft memo Fackler recognizes that in the event the State contracts with APC for the royalty gas from the North Cook Inlet field the point of taking and the transportation charges would become key issues.

Famous "last" words!!!!!!!

Comment by Dale Teel in a Memo to File dated March 10, 1977--

"It thus is clear that the State places the State's interest above the interests of our ratepayers to the extent we have to pay more than would result from export of this gas. It does not follow that the Lessee who has made the investment required for production, gathering, and compression of royalty gas can be or should be held responsible to deliver the royalty gas at less cost than the Lessee determines to be necessary, fair, and reasonable."

Comment by Dale Teel in a Letter to Don Wold dated April 15, 1977--

"...(I)t would be no more logical to require Phillips to accept less than their required price than for the State to accept less than it deems to be necessary for this gas."

Comment by Dale Teel during Briefing in Governor's Office by Don Wold with interested legislators, April 22, 1977--

"These costs are reasonable" when queried what his analysis of the Phillips' proposed charges for transportation and compression was.

U-75-68(3) states that

"(T)he cost of gas purchased from the State is greater than the cost of gas purchased from other suppliers." This statement talks about the purchase price from the State, it does not deal with transportation and added compression charges, as proposed by Phillips, since they weren't even part of the picture then

p. 5

"(T)he Commission has specifically allowed flow through of ... royalty gas purchases from the State...." (filed July 31, 1975)

p. 7

The order states that the flow/through provisions proposed by AGAS for added gas costs were "...so broad that nearly all increases in any... cost of purchased gas could be flowed through." (emphasis added)

p 7

This would indicate that the APUC was very much concerned with allowing automatic flow through

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of all added costs

The order states that if AG&AS is able to purchase royalty gas from the State it will be "somewhat higher" than the price

p8 of gas from other gas supplies now committed to AG&AS. Somewhat higher does not mean doubling the price!!! (41.5¢/Mcf vs. 84.65¢/Mcf).

p9 The order requires that a quarterly report be filed by AG&AS with APUC to allow the Commission to audit the fluctuation of rates charged which are the result of allowing the commingling of higher priced royalty gas with cheaper gas.

p10 The order states that the Commission estimates that the commingling of royalty gas with other gas will fall in the range of 2-5¢/Mcf/month. Does the

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Commission still believe these increases to be accurate in light of the added 20¢? Where are the figures and computations to arrive at the 2-5¢/Mcf/month charge?

p 10 The Order requires that if the royalty clause was not used to reflect an average cost on or before August 1, 1976 (as, of course, it wasn't), the Commission would commence an investigation to determine "... whether the (royalty) clause should be deleted from the tariff of AG&AS." This apparently never happened. The APUC was apprised by AG&AS of the "difficulties" they were having getting the gas to shore (Sept. 29, 1976) with Phillips asking that AG&AS fund the first phase of a compressor station on Phillips' platforms at a cost of $5MM as a condition

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to delivering the royalty gas to shore. AGAS countered with a pro-rated share of compression costs based on volume and a couple of other concessions (when and as available delivery, and "reselling" excess royalty gas back to Phillips). Since the APUC apparently did not pursue the matter it is not known to what an extent they were aware of the added costs which were required to get the gas to shore. AGAS discouraged the APUC "...to develop 'a complete record' of the negotiations (between AGAS and Phillips) for the Commission's files...", but was agreeable to informal discussions with the APUC. In that same context AGAS does state that they "...clearly ... need to preserve the flow through provision in order to continue ... negotiations (with Phillips)." It looks as if APUC dropped the ball somewhere along the line

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to stay on top of fluid as it developed.

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1 Phillips has a contract with Tokyo Gas and Tokyo Electric which expires 6/1/84 which is supplied from the North Cook Inlet gas field (including the State's 1/8 royalty share).

2 Fackler suggest in his November 19 draft memo that the contract term for the State should not exceed the Phillips contract terms above (which, I guess, means that the commitment of our royalty gas should not run beyond 6/1/84), and that contract terms for the State should also include a provision to protect the State if Phillips' production is terminated for any reason.

3 Fackler's memo of November 19 indicates that APC expected to pay its proportionate share of additional transportation or compression costs either in the form of con-contributing capital or paying higher transportation charges per Mcf or month (or terminating the taking of royalty gas within one year - draft of proposed sales agreement, dated 12/7/75).

4 November 19 memo mentions that Phillips had raised the issue of the APUC classifying their pipeline (from platform to LNG plant) as a utility (if it transports gas for a third party (APC), and that Phillips would not transport the gas if they came under APUC jurisdiction.

5 The draft for a proposed North Cook Inlet royalty gas sales agreement, dated 12/7/75, stipulates that neither Phillips (nor Union) shall come under APUC or any other regulatory authority as a result of the sale of royalty gas to APC. If regulatory jurisdiction were ever asserted or implemented the agreement would be terminated.

6 The "Memorandum of Understanding" draft (12/7/75) states that "APC will receive the State royalty gas only to the extent it may be available without additional investment for transmission (or compression) by Phillips..." This is subsequently qualified by providing that if any investments were necessary to allow for continued delivery of the State's royalty gas APC would have the option

a to participate equitably in such an investment, or

b to pay a mutually acceptable price per Mcf or per month, or

c. to terminate the agreement to take the State's royalty gas.

(See Fackler's November 19th memo which also covers this).

7 Phillips (John Horn) stated the following "complicating matters" in this letter of January 9, 1976 to APC.

a. That while a 5.55¢/Mcf figure has been used to establish the wellhead value for purposes of paying royalty and taxes, it did not represent the appropriate differential (transportation and compresion). They did not say what the appropriate figure was or should be.

b. That neither Phillips nor any of its facilities could be subjected to the possibility of being classified as a public utility by the APUC, and that without an assurance to that affect no agreement would be entered into.

c. That the "exchange" of gas from the North Cook Inlet field with gas from the Kenai gas field, suggested by APC, would have to be worked out between APC and Marathon, and Phillips would not be a party to such an arrangement.

8 APC advised Union, Marathon and Phillips on December 12, 1975 that the Royalty Board at their December 10 meeting had authorized the Commissioner of NR to negotiate the sale of North Cook Inlet gas field royalty gas to APC.

9 The December 10 Royalty Board vote on the above was unanimous, although Arlon Tussing raised the question whether APC had tried hard enough to get gas elsewhere. As a result APC then asked Union and Marathon (their December 12, 1975 letters) if they were willing to offer APC like "deals" as the royalty gas they were negotiating for; ie.,

50 Bcf to June 1, 1984

15 MMcf/day; take or pay at 10MMcf/day

55.8¢/Mcf (50.25¢/Mcf + 5.55¢/Mcf for transportation)

10 Marathon declined (December 19, 1975), but came up with a proposal for a short-term contract similar to their existing contract for an additional supply of gas (up to 5 Bcf) for one year/ or to May 1, 1978 whichever occurred first at a price

of 55.8¢/Mcf.

11 APC's letter of 2/3/76 indicates that they now felt that they would have to build their own pipeline from the LNG plant to their pipeline rather than to rely on "paper exchanges" as suggested earlier.

12 This they argued would required a longer term though (the Royalty Board had proposed a seven year period to June 1, 1984) since it would be impractical for APC to ammortize a pipeline over such a short time. They asked to receive a contract for royalty gas for the life of production from the North Cook Inlet gas field. (2/3/76).

13 Homer Electric Association also applied for the North Cook Inlet gas field royalty gas (February 23 Royalty Board meeting - APC letter to Homer Electric Association of 2/25/76, letters from APC to Guy Martin of 2/27/76 and 3/9/76 - Also see Homer Electric File on this). Phillips also applied for the North Cook Inlet field royalty gas, as did Pacific Alaska LNG. (Letter of Guy Martin to APC dated 3/17/76).

14 Homer Electric Association was subsequently made an offer by K.U.S.Co for needed gas at a considerably lower price than the royalty gas price being then considered. 48.24¢/Mcf vs. 55.8¢/Mcf. However, HEA did re-enter the picture later. (See File).

15 An undated memo entitled "Commissioner's Proposal in Concept" states that APC would be responsible for measurement costs, and any compression or dehydration costs if or when necessary.

16 As of APC's letter dated 4/9/76 they intended to build a pipeline from the P-M LNG plant to their existing Anchorage line.

17 A contract (76-1) was executed between the Royalty Board and APC on 6/4/76 with provisions shown in Appendix "A".

18 Since under the above contract APC would have to take the royalty gas at the wellhead, a suggested gas gathering agreement between APC and Phillips provides that unless the contract between the State and APC is amended to accommodate Phillips, the "agreement" between APC and Phillips could be terminated. (Page 11 of the Gas

Gathering Agreement between APC and Phillips; last paragraph).

19 The Gas Gathering Agreement between APC and Phillips provides for and states among other things that

a. APC will accept delivery of the royalty gas at or near the wellhead.

b. Phillips is willing to gather the royalty gas for APC and deliver it at a mutually agreeable point near the Kenai LNG plant.

c. Phillips will need to provide additional compression capacity to handle the added royalty gas in kind production through its gathering system.

d. Since APC can't justify participation in the installation of additional compression capacity which is required to delivery the State's royalty gas, APC agrees to accept delivery of royalty gas as it becomes available from time to time.

e. The added supply of royalty gas would be used to service existing and potential new customers in the vicinity of the Kenai LNG plant only for the above stated reason (amount of gas not sufficient to allow for participation in adding additional compression capacity).

f. Point of delivery shall be at or near the existing pipeline tap now used to deliver gas from the Phillips pipeline to the Tesoro refinery in the general vicinity of the Kenai LNG plant on the North Kenai Road. (This would seem to indicate that Phillips sells gas to the Tesoro refinery from the North Cook Inlet field--I thought all that gas went to Japan--check this out). In a different portion of the "agreement" the point of delivery is to be "...at the juncture of APC's facilities and Phillips' facilities located near the pipeline tap service the Tesoro refinery..." (Check out if necessary. It is inconsistent it seems to me).

g. Odorization of gas shall be APC's responsibility, and Phillips shall be held harmless.

h. APC shall pay Phillips 10¢/Mcf for <u>delivery</u> from platform to delivery point

and for dehydration (what is involved in dehydration?). This 10¢ charge is to increase by 6 percent annually.

i. APC shall pay Phillips in addition to the above gathering charge a compression charge of 10¢/Mcf. This, too, would increase by 6 percent annually.

j. APC shall pay Phillips (in addition to the above) a mutually agreeable charge for added compression when and if it is necessary, based on APC's share of added volume.

k. In addition, APC shall reimburse Phillips in the proportion of deliveries made to APC by Phillips for any new or increased fees, charges, taxes, etc. applicable to gathering of the gas (including compression) which would be imposed on Phillips prior to delivery of royalty gas to APC.

l. Phillips by delivering royalty gas to APC does not "...render any service to or for the public;" ie., will not become a utility subject to regulation.

APC makes the material representation to Phillips that Phillips will not be subject to regulation by the FPC or APUC.

20 In a letter to Don Wold dated 2/2/77 APC first mentions the "desirability" to to have the State take deliverability of its royalty gas onshore so as to avoid the necessity for APC to negotiate a seperate agreement with Phillips.

21 The letter also indicates that they would not be committed to install a pipeline connecting to their Anchorage line; that they would accept only such gas as they can readily re-sell up to 100 percent of royalty gas which is available with the rest to be royalty gas in value to Phillips. (The reason for this is cited as the shortness of the contract; ie., July 1, 1984 vs. life of production, which is what APC wants).

22 The same letter also indicates that they would pay the proportionate share of additional compression facilities Phillips' were to install at a future time.

23 APC in a memo to file dated 3/10/77 made a very interesting point, I think, by stating that the 10¢ transportation/gathering charge Phillips would charge is still much cheaper than <u>any</u> alternative which exists to them or to the State for that matter, other than possibly bad publicity within the state for Phillips.

24 The APUC in its order No. 3, Docket U-75-68 (12/17/75) (p. 10) states that they believe the commingling of cheaper gas with more expensive North Cook Inlet royalty gas and averaging the cost will generally amount to 2 - 5¢/Mcf/month for the customers of APC.

25 The same order also states that if the provisions allowing flow through of costs was not used by August 1, 1976 the APUC would commence an investigation to determine the non-use and to determine whether the provision should be deleted from the tariff of APC. (See Sept. 29, 1976 letter to APUC).

26 A letter of APC to APUC dated September 29, 1976 states that the contract with the State (76-1) could not be carried out because --

a. APC would have to pay State the highest price within a 100 km/radius (62 miles) (they had hoped no more than the price of gas liquefied for export).

b. APC would have to take <u>100 percent</u> of royalty gas produced;

They do not have sufficient sales on the North Kenai Road for the full amount;

On the other hand, they do not have facilities to interconnect with their Anchorage line; and

They have been unable to work out an agreement for an exchange with Kenai gas.

c. The contract expires July 1, 1984 (instead of the life of production as APC would desire) which APC claims is too short to invest in the facilities which are required.

27 The September 29, 1976 letter also indicates that Phillips wanted to have APC fund the first phase of a compressor station on the platform (approximately

$5,000,000) in return for their delivering the royalty gas to shore. APC countered with an offer that they would

a. Pay a pro-rata share for compression (volume) with a right to discontinue after a year's notice; and

b. Resell any "excess" royalty gas back to Phillips for the same price they would have paid to the state; and

c. Forego taking royalty gas if and when the pipeline capacity throughput was limited (a standby gas supply to make the above possible had not been found, and it was mentioned that APC might have to build a pipeline from their Anchorage line to the delivery point on shore to guarantee such standby volumes as are necessary).

(This should be looked at more closely because (1) having APC pay for the compression facilities necessary to deliver royalty gas is an interesting idea since it could reasonably be expected that certainly those costs would be subject to APUC scrutiny in setting a rate for the APC royalty gas, and (2) because now APC talks about building a pipeline <u>from</u> their Anchorage line to the delivery point to provide for standby volumes when in the past they had talked of building the pipeline from the delivery point <u>to</u> the Anchorage line to take such royalty gas as could not be consumed on the North Kenai Road. It would seem to me that since a pipeline is being considered between the two points, then APC could take <u>all</u> royalty gas instead of reselling any "excess" gas back to Phillips as proposed in b. above).

(As it stands now APC does not even pay a pro-rata share for the added compression, but 10¢ (20¢) or 20¢/Mcf (depending on which document one looks at--Appendix "B", the "New" contract or Phillips' letter to Don Wold dated 3/3/77). The pro-rated cost/ would be applicable only after the initial installation of the first compression unit).

28 The AG (Will Condon) in a memo to Guy Martin, dated 3/7/77, determined that the APUC would not have jurisdiction over Phillips pipeline because Phillips does not fall into the category of "...a 'utility' nor 'public utility' within the meaning of the Public Utilities statute, because it will not be furnishing transmission service to the 'public' or the 'Alaska public' Phillips would be furnishing transmission service to the State." which is certainly not a utility
(That is not so, since the current contract provides for APC to take delivery at the platform. Check with Will Condon).
(Is language necessary to change the current law??)

29 The lease with the State provides that the royalty gas has to be taken in the field (Phillips March 3, 1977 letter to Don Wold).

30 The application for a right-of-way permit (2/15/68) to build two 10" gas pipelines and appurtenances from platform to shore could be "used" to demonstrate that the pipeline is for public use, since "public" was not crossed out in the application (although it could have been).

31 The Royalty Board authorized Commissioner of Natural Resources to negotiate a sale for the North Cook Inlet roaytly gas on December 10, 1975.

32 Contract 76-1--ALL OF THE ROYALTY GAS AVAILABLE. The exact amount of royalty gas available each day cannot be determined since volume depends on production, over which the State has not control. However, the daily production averages approximately 15MMcf/day as determined by previous years' production.

33 The amount of royalty gas being contract for or being sought by APC to meet their requirements range all the way from life of production to 75Bcf - 50Bcf - 40Bcf (4/2/76 letter from APC to Guy Martin).

34 In the context of this issue Union-Marathon)

Union) are the same
Marathon)

APC has contract with the above, and the above own transmission line from LNG plant to Nikiski. (see point 35).

35 Union is the operator of the Kenai gas field for the interest of both Union and Marathon, as well as the operator for the transmission line on the North Kenai Road.

36 16" line mentioned in "Gas Gathering Agreement" (p. 6) "...gas delivered... from the 16 inch pipeline service the North Cook Inlet Field...".

37 The initial contract, 76-1, would have provided for APC to take the royalty gas at the wellhead. This is evidenced by their "Gas Gathering Agreement" with Phillips.

38 To avoid APUC jurisdiction over Phillips APC proposed that they take delivery of the gas on shore from the State. To affect this change proposed the "new" contract.

39 Homer Electric Association (HEA) enters into the picutre again as the proposed new owner of the Bernice Lake power plant hoping to buy gas for electric power generation from APC. APC has supplied this gas up to now--in fact it represents 90 percent of its volume under the U-M contract-- to Chugach Electric from which HEA hopes to buy the Bernice Lake power plant. It seems [illegible] that gas fuel supply is not certain at the Bernice Lake power plant after April 30, 1977, after the expiration of APC's 10Bcf contract with U-M although that contract was extended for one year (check this out).

40 They need approximately 8MMcf/day at the Bernice Lake power plant according to a note by Don Wold dated 11/30/76, and a letter dated 2/11/77 from HEA which shows present need for 5,700 Mcf (with winter peak loads as high as 9,000 Mcf) for up to 8,000+Mcf (with winter peak oads of up to 17,000Mcf) per day after January 1, 1979.

41 In a letter to Don Wold, dated 11/30/76, HEA again ask for the North Cook Inlet royalty gas because

1. of APC's inability to guarantee uninterrupted and continuous supply to the Bernice Lake power plant (and unwillingness to give HEA permission to obtain

needed gas from other sources since APC claims that the Bernice Lake power plant is in APC's certificated service area); and

2. APC's proposal to return that part of the royalty gas they cannot readily use to Phillips.

HEA's reasoning--quite logically--is that

1. They are essentially the only customer APC would supply with the royalty gas (ie., who needs APC??); and
2. That while they cannot use 100% of the royalty gas either they will negotiate a sale for the surplus so as to assure the State a market for all its royalty gas from the North Cook Inlet gas field instead of returning part of it to Phillips. The only trouble is that in the 2/16/76 letter they offer to take the royalty gas in the amounts outlined in their 2/11/77 letter (see point 40 above) which would not constitute 100% of the royalty gas.

42 HEA, too, is seeking APUC assurance that the state's royalty gas they would purchase would not come under APUC jurisdiction since their use of the gas "...will be for purposes of manufacturing electrical energy for resale under tariffs directly under the control of the Commission." (Their letter 12/9/76 to APUC).

43 HEA offers to pay the State 60¢/Mcf delivered to the Bernice Lake power plant (Their letter dated 2/16/77). (The power plant is a stone's throw away from the LNG plant, probably no more than a 1/4 mile).

44 In his letter to Guy Martin (dated 2/15/77) Don Wold states that if the "new" contract were accepted (and the APUC not exercise jurisdiction over the Phillips pipeline as per Will Condon's opinion dated 3/7/77) then "...it seems that the Department of Natural Resources will in fact assume a portion of the responsibilities of the APUC in determining whether or not the pipeline tariff and compression charges are in the interest of the State." What has the DNR decided about the charges? Are they fair? What is the justification over and above the costs furnished by Phillips in their 3/3/77 letter?

APPENDIX "A"

KEY PROVISIONS

	CONTRACT 76-1	"NEW" CONTRACT
Quantity:	All royalty gas available, when and as available.	APC would take UP TO all of the royalty gas available. This means APC would not be required to purchase all royalty gas. How does this jive with their previous argument that they needed new reserves and supplies to service their existing customers: The the royalty gas amount (15MM - 17MMcf/day APC "Proposal" p. 4. and 5 and "Commissioner's Proposal in Concept") available from the North Cook Inlet field was just the right amount needed to supplant their loss of Kenai gas field supplies?
Delivery Point:	Delivery point shall be the same for APC as it has been for State. This appears to be the platform since a proposed gas gathering agreement between APC and Phillips states that the contract between the State and APC provides that "...APC will accept said royalty gas at or near wellhead in the North Cook Inlet Field...". Gregg's memo of May 8, 1976 to Fred Brown (p. 2) confirms this. However, a memo from Don Wold to Guy Martin dated 2/14/77 states that APC "...must take delivery from Phillips near the terminus of the Phillips terminus of the Phillips pipeline located near the North Kenai Road...." according to the 76-1 contract. (I don't think he is correct in light of the above).	Delivery point would be on shore at or near Phillips' pipeline tap which delivers gas to the Tesoro refinery.
Price:	A. 1. To July 1, 1977 — 55.5¢/Mcf 2. July 1, 1977 - July 1, 1978 the higher of a. — 60.36¢/Mcf or b. price State would have received had it continued to take its royalty gas in value — or c. the highest price paid by any purchaser in the Upper Cook Inlet area (within a 100 km radius of Phillips' platform) for similar quality gas and similar conditions of delivery. 3. July 1, 1978 and each succeeding 12 month period the higher of a. the previous year's price plus 2¢/Mcf — or b. above — or c. above.	A. 1. To July 1, 1978 — 64.65¢/Mcf 2. July 1, 1978 - July 1, 1979 the higher of a. — 66.65¢/Mcf or b. price State would have received had it continued to take its royalty gas in value — or c. the highest price paid by any purchaser in the Upper Cook Inlet (within a 100 km radius of Phillips' platform) for gas of similar quality gas and similar conditions of delivery. 3. July 1, 1979 and each succeeding 12 month period the higher of a. the previous year's price plus 2¢/Mcf — or b. above — or c. above

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		B. 1. 10¢/Mcf for gathering costs to point of delivery to increase 6 percent per year on the anniversary date. 2. An additional 20¢/Mcf after Phillips has the first unit of added compression facilities (approximately 3500 hp) to increase 6 percent per year on anniversary date. 3. Additional charges for future compression facilities which may be required and installed in proportion to gas received. (Interestingly, the proposed contract calls for such additional costs under 8. 3. to be verified by the State, which would seem to indicate that in this instance Phillips would agree to "jurisdiction" by the State). (To be consistent with Sec. 7.2 of the "new"contract should this be removed?)
Term:	Effective: Upon approval by the Legislature 5/20/76 Expiration: July 1, 1984	Effective: Upon approval by the Legislature Expiration: July 1, 1984
Termination Clause:	Allows APC to terminate the contract within 30 days of written notice to State if APC is unable to make satisfactory arrangements to take delivery of the royalty gas.	Allows APC to terminate the contract within 30 days of written notice to State if APC is unable to make satisfactory arrangements to take delivery of the royalty gas. This seems absurd since APC would now take delivery on shore! What is meant by "...unable to make satisfactory arrangements to take delivery of the gas."?
Conditions Precendent:	Not covered.	Provision providing that Phillips would not come under the jurisdiction of the FPC or APUC or APC (Section 7.2 of Article VII).
Miscellaneous:	Not covered.	Assignments of interest by APC may be made "...to conform with...(APC's) various financing documents or as may be desirable to...(APC) as to...(APC's) commonly owned affiliate or subsidiary." (Who are they?)

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QUESTIONS

1. What is "Rate PI"? (Power Interruptable--no longer in existence) (See letter 12/2/75 to APUC by ANG).

2. What was or where is a copy of the "special contract" with Chugach and ANG? No applicable to our inquiry according to Russ Staley of the APUC (See letter 12/2/75).

3. Was Section708 of ANG's tariffs ever reinstated? No. If yes, what does the flow through provision provide for? Sec. 708 and 709 would have allowed AGAS to flow through--by means of a billing surcharge--any increase in its wellhead cost of gas above 41.5¢/Mcf occurring after July 1, 1975 as well as any new or increased taxes imposed by Federal, State, Borough, or local taxing authority upon production, etc.--reserves taxes--above the amounts established on January 1, 1975. (See Order No. 3, U-75-68. Also see Enclosure A and B to letter dated 4/2/76.

4. Who is Pacific Alaska LNG Company? Have they dropped out of the game trying to contract for the State's royalty share from the North Cook Inlet field? Yes. (See "Findings and Conclusions for Non-Competitive Sale", dated April 26, 1976, bottom p. 2).

5. What, if any dehydration or compression charges were assessed the State when it took its royalty gas in value? None. How can these by justified over and above the added compression necessary to produce additonal quantities to make up for the royalty gas loss!?

6. The right-of-way permit application specifies two 10" pipelines; the "Gas Gathering Agreement" states one 16" pipeline. Which is correct? Does it make a difference? 2-10" from platform to shore; 1-16" on shore to LNG plant.

7. Did the APUC ever approve the flow through charges which would include the 10¢ for transportation and dehydration and the additonal 10¢ (20¢) for added compression? and if so, how were these charges justified by APC to APUC? See Order No. 3, U-75-68, 12/75/75. Call APUC to see if it was applicable! Commissioner Zerbetz (4/18/77) informed me over the telephone that "it would appear that the flow through charges of 10¢ and 10¢ for gathering and compression are valid under U-75-68 (3). See Don Wold's letter to Guy Martin (p. 2 last paragraph) which suggests that APC does not have to justify these increased costs to the APUC.

   Check with APUC if their Order No. 3, U-75-68 (12/17/75) ever intended to allow flow through of costs regarding gathering costs (transportation, dehydration, including compression) or whether they merely meant the price the State was receiving from its royalty gas. APC treat it as if these added costs were included in the order.

   At the time the order was issued--12/17/75--the price APC was using was 45¢/Mcf price at wellhead and 5.45¢/Mcf delivery to LNG plant for a total

of 54.45¢/Mcf for the royalty gas. (It is not clear to me if the APUC is working with the 50.45¢/Mcf figure, or a figure of 74.65¢ (84.65¢) considering the added transportation (and compression charges) Phillips wants to charge for delivering the State's royalty gas to shore.

APUC was apparently apprised of some of the difficulties encountered by APC taking delivery of the royalty gas and the costs which would be involved by APC in their letter to the APUC dated September 29, 1976, but there is no indication that they ever acted or commented on these potential charges.

8. Why the difference in price of transportation and dehydration for the State and APC 5.55¢ (5.45¢) vs. 10¢/Mcf? Need a reasonable justification from Phillips, APUC, Don Wold--anyone? Don Wold explained that 5.55¢ charge is a charge Phillips assessed to arrive at the wellhead value of the gas for tax and royalty purposes (it is anyone's guess why they prefer to keep it at that rate*-- depletion allowance was mentioned). The 10¢ which Phillips plans to charge APC for transporting the gas to shore is what Phillips decided it is worth to them as a business venture, earning a return.

   See Memo to File by APC in which Dale Teel writes that it is not reasonable to expect that "...the Lessee who has made the investment required for production, gathering, and compression of royalty gas can or should be held responsible to deliver the royalty gas at less cost than the Lessee determines to be necessary, fair, and reasonable." In a later letter to Don Wold Teel says that "...it would be no more logical to require Phillips to accept less than their required price than for the State to accept less than it deems to be necessary for this gas." (4/15/77).

   *Why were they willing before to settle for less? Why would they give the State a break?

9. Why was the price for royalty gas raised from 60.36¢ (76-1) to 64.65¢ in the "new" contract, which is a 4.21¢ difference inless than a year? This is the new wellhead value established by Phillips. The current contract provide for 64.65¢ with various increase options annually, accepting that which is the higher of these options. Those options are favorable to the state, but not necessarily to APC, since one of them calls for APC to pay the highest price paid by any purchaser in the Upper Cook Inlet (within a 100 km radius of Phillips' platform) for gas of similar quality gas and similar conditions of delivery. In their April 15, 1977 letter to Don Wold APC mentions that Pacific Alaska LNG is paying $1.45 in the Cook Inlet. I do not know if they would fall into the 100 km radius of Phillips' platform.

10. What led to the decision not to dispose of the North Cook Inlet royalty gas by competitive bid, but rather negotiate the sale with APC? Guy's letter of 3/17/76 sates that "...the Commissioner must publish the specific findings and conclusions supporting that decision." (See Commissioner's Proposal in Concept and attachments).

11. Get deliverability cost to APC under the U-M contract for the North Kenai Road. Dale Teel advises in his 4/15/77 letter that U-M charged them 1.5¢ above the Anchorage contracts basic price (24¢), but that this did not constitute a deliverability charge! This is not the way I understood it from Bill Hickman of APC. According to Teel there is

no transportation charge charged APC by U-M on their transmission line from the Kenai gas field to the North Kenai Road.

12. What is Rate "SK-5" mentioned in APC's letter to HEA dated 11/16/76?

    Rate Schedule of APC (according to Russ Staley of the APUC)

a	Schedule A	Residential
	AA	Residential with APC furnishing Equipment
	B	General Service (small commercial)
	BB	Gen. Serv. with APC furnishing Equipment
	C	Large General Service (Apartments & Industrial)
	CC	Lg. Gen. Serv. with APC furnishing Equipment
	I	Interruptible Rate
	SK	Soldotna/Kenai Rate

13. Is the Bernice Lake power plant in APC's certificated service area? Yes (Russ Staley-APUC) According to Russ Staley a certificated service area is not exclusive but normally the APUC do not allow more than one utility in one SA. This seems to be a bone of contention in the instance where HEA wants to secure gas for the Bernice Lake power plant which they hope to buy from Chugach from other sources in APC's SA if APC will not or cannot guarantee them a continuous supply of gas. See 11/30/76 letter.

14. Has any action been taken on HEA request for a waiver of jurisdiction by APUC over royalty gas? How sound is their reasoning that the gas ought to be exempted since it is used to manufacture electricity which is under APUC jurisdiction?

15. What has DNR done to ascertain whether the proposed transportation costs (10¢) and compression charges (10¢) are fair? Don Wold informed me that this was not the Royalty Board's responsbility.

16. What is "just and reasonable" in terms of a flow through provision? Commissioner Zerbetz advised me on 4/18/77 that under current statutes it would be very difficult to disallow flow through charges, which were bonafide costs incurred by the utility.

17. Under 9.1, 9.2 and 9.3 of the Phillips/State contract the state is a party to the gathering and compression charges. If we "allow" this what are the implications for setting a precedent for future similar situations?

    How can the State "agree" to charges without being sure they are "just and reasonable"?

    As written now State is agreeable to the 20¢ + for gathering and compression being charged by Phillips. How can we do this and be assured these charges are not excessive?

    Don Wold suggested in a conversation with Gregg and myself 4/18/77 that he finally had determined why APC wanted to get the royalty gas so badly. He said it was for the purpose of setting a precedent for other situations similar to the current one; ie., where the gas is offshore, avoiding APUC or APC jurisdiction of gathering and compression costs).

18. Why should State/APC pay added taxes, fees, imposts, etc. (9.4 ( ) and 6.1(f) imposed on Phillips? This seems unreasonable! I was told that Phillips was adament about this provision. It has been suggested that Phillips is using this to discourage oil and gas tax hikes.

Pete Froehlich suggested that if any taxes, etc. be paid by State/APC such taxes should only be on <u>new facilities</u>. However, he said his suggestion was not accepted.

Telephone conversation with 4/1/77

Russ Staley - Chief - Eng. Section - APUC

Answers to questions —

+ SK-5

✓ 1.) Rate PI ^ probably refer to inter-
✓ 15.) ruptable power rate, but Russ will check on it.

2.) He will furnish me with copy of special contract with Chugach Electric Association if it is applicable in any way to the business at hand, i.e., North Cook Inlet royalty gas to APC

3.) Yes. The "wellhead cost" referred to in Order No 3, U-75-68 applies to all of the Kenai gas field gas APC receives from U-M ^ according to Russ Staley, since that is the only contract APC has for gas. He stated that he believed that the flow through provision would, however, also apply to the North Cook Inlet royalty

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gas — that the APUC would consider this flow through tariff provision for added well head and reserves tax costs as a "multiple position"; i.e., not just applying to one case. However, he really did not know, and will check with Susan Knowles who was the commissioner who handled this order.

(an accurate answer to this is very important, it appears to me, since the intent of what added costs would be allowed to be flowed through has major significance now that Phillips wants to charge up to 30¢ for transportation and compression costs).

4) Pacific Alaska LNG Co is a California based outfit which has been trying to build a liquefaction plant at Kenai. They are still seeking FPC approval to build the plant.

7. Will get back to me. Does not know.

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8. Does not really know. Believes that the APUC wasn't aware of the cost differentials. Will check and advise.

12. See 8. above

14. Russ Staley will send me a copy of contract between APC and U-M (which has <u>deliverability cost</u> in it).

The Kenai gas field is produced <u>on shore</u>

APUC waived jurisdiction on the "North Kenai Road" transmission line of Union's because only appx. <u>2%</u> of the gas goes to the public. The rest goes to industry, mostly to Collier (a wholly owned subsidiary of Union) and the Swanson River field. Russ Staley referred to it as "in-house" gas.

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16.) Yes. The certificated service area, which Russ Staley called a "franchise" is not exclusive he said, but normally, APUC does not allow more than one utility in one SA.

17.) Does not know. Is only familiar with the AG's opinion which waives jurisdiction over Phillips; not aware of the apparent different reasoning applied by HEA.
Will need further info on this!!

18.) Does not know. Will attempt to find out.

General: The individuals most familiar with this matter, both among the staff and the commissioners, are no longer here. Thus, nobody is really up on this. It may be necessary to go up to Anchorage and sit

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down with Commission staff to get all the answers and an idea of their thinking, which we don't know what it is.

Russ Staley said he would call back 4/12 or 4/13 with answers to my questions.

My overall questions were

1.) How is the APUC viewing flow through of the Arp to 30¢/Mcf charges for transportation and compression of North Cook Inlet royalty gas to APC; and

2.) What attitude are they taking regarding jurisdiction over the Phillips line.

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Meeting with Will Condon
Fred Boness +
Pete Froehlich

4/13/77

① If the pipeline is not under APUC or APC jurisdiction (as proposed under the revised contract) how can the State "control" the high price charged for transportation + compression

Transportation / gathering chgs were previously assessed the State at 5.45¢ (5.55¢)

last year - 12¢ - 65¢ range for taxes on royalties

② - Do we have a def of common carrier? Yes!

- Does it subject itself to regulation by virtue of being a common carrier? Yes!

//

Subject to APC jurisdiction by virtue of CC status accdg to Will Condon

Fred Boness said that the purchase of the North Cook Inlet royalty gas by APC constitutes their "buying less rapid depletion of reserves already committed to anchorage"

AGO 801263

* This could, of course, also be read that they are adding to their reserves for Anchorage now at a more reasonable cost than would be available later.

Supposedly, APC is experiencing a shortage of dedicated reserves. ready to Fred Boness.

AGO 801264

Sec. 42.06.600. Regulation by municipality. The commission's jurisdiction and authority extend to an oil or gas pipeline facility operating in a city or borough, whether home rule or otherwise. If a conflict between a certificate, order, decision or regulation of the commission and a charter, permit, franchise, ordinance, rule or regulation of such a local governmental entity occurs, the certificate, order, decision or regulation of the commission prevails. (§ 1 ch 139 SLA 1972)

Sec. 42.06.610. Expenses of investigation or hearing. After completion of a hearing or investigation held under this chapter, the commission shall allocate the costs of the hearing or investigation among the parties, including the commission, as is just under the circumstances. The costs allocated may include the costs of any time devoted to the investigation or hearing by hired consultants, whether or not the consultants appear as witnesses or participants. The commission shall provide an opportunity for any person objecting to an allocation to be heard before the allocation becomes final. (§ 1 ch 139 SLA 1972)

Sec. 42.06.620. Classification. The commission may by regulation provide for the classification of oil or gas pipeline facilities based upon differences in annual revenue, assets, nature of ownership and other appropriate distinctions and as between these classifications, by regulation, provide for different reporting, accounting and other regulatory requirements. (§ 1 ch 139 SLA 1972)

Sec. 42.06.630. Definitions. In this chapter

(1) "commission" means the Alaska Pipeline Commission;

(2) "commissioner" means a member of the commission;

(3) "duties" means duties, powers, obligations and functions;

(4) "gas" includes all natural gas and hydrocarbons produced at the wellhead and not defined as oil;

(5) "Interstate Commerce Act" means the Interstate Commerce Act of 1906, 34 Stat. 584, as amended;

(6) "municipality" means an organized borough or incorporated city;

(7) "Natural Gas Act" means the Natural Gas Act of 1938, 52 Stat. 821, as amended;

(8) "oil" includes crude oil, and other hydrocarbons regardless of gravity which are produced at the wellhead in liquid form, its products and liquid hydrocarbons, including the liquid hydrocarbons known as distillate or condensate recovered or extracted from gas, other than gas produced in association with oil and commonly known as casinghead gas;

(9) "pipeline" or "pipeline facility" means all the facilities of a total system of pipe (whether owned or operated by a pipeline carrier under a contract, agreement, or lease) in this state used by a pipeline carrier for transportation, for hire and as a common carrier, of oil or gas for delivery, storage, or further transportation, and including all pipe, pump and compressor stations, station equipment, and all other facilities used

See 38.35.120

or necessary for an integral line of pipe to effectuate the transportation from point to point, excluding, however, gas processing plants, treaters and separators;

(10) "pipeline carrier" means the owner, including corporations organized under the laws of the United States or of other states, of any pipeline, as the term is defined in this section, or any interest in it;

(11) "regulation" includes rules;

(12) "tariff" means a rate, charge, toll, rule or regulation of an oil or gas pipeline facility relating to services furnished by the facility to the general public or other users for compensation. (§ 1 ch 139 SLA 1972; am §§ 7, 8 ch 6 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote paragraphs (4) and (8).

Sec. 42.06.640. Short title. This chapter may be cited as the Alaska Pipeline Commission Act. (§ 1 ch 139 SLA 1972)

Chapter 07. Alaska Transportation Commission Act.

Article
1. Establishment of Transportation Commission (§§ 42.07.011 — 42.07.111)
2. Powers and Duties of Commission (§§ 42.07.121 — 42.07.161)

Repeal of former chapter. — Section 1, ch. 104, SLA 1969, repealed former Chapter 07, entitled "Alaska Transportation Commission." The former chapter consisted of §§ 42.07.010 — 42.07.150, and derived from § 1, ch. 139, SLA 1966.

Article 1. Establishment of Transportation Commission.

Section
11. Creation and composition
21. Term of office; vacancy
31. Quorum
41. Qualifications
51. Oath of office
61. Restrictions
71. Compensation of members of the Alaska Transportation Commission
81. Principal office and seal
91. Legal counsel
101. Employment and compensation of personnel
111. Annual report

Sec. 42.07.011. Creation and composition. (a) There is created the Alaska Transportation Commission within the Department of Commerce and Economic Development. The commission consists of three members appointed by the governor and confirmed by the legislature in joint session.

(b) The governor shall designate one member of the commission as chairman of the commission. This member shall serve as chairman for

to comply with its terms, conditions, and obligations. Only upon proper acceptance of offered lease by the applicant within 30 days after its having been presented is the grant of the application consummated. (§ 1 ch 72 SLA 1972; am § 9 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.110. Term of lease. Each lease of state land for pipeline right-of-way purposes shall contain a provision that the lease shall run for a specified term of not greater than 30 years, and shall be renewable for additional periods of up to 10 years each, so long as the lessee is in commercial operation and is in full compliance with all state law, including but not limited to state law pertaining to regulation and taxation of the pipeline facility, and is in compliance with all terms of the lease. In making this determination he shall take into consideration the cost of the proposed pipeline, its useful life, and the probable financing requirement for the proposed pipeline. (§ 1 ch 72 SLA 1972; am § 10 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment substituted "30 years" for "25 years" and inserted "is in commercial operation and" in the first sentence and added the second sentence.

Sec. 38.35.120. Covenants required to be included in lease. (a) A noncompetitive lease of state land for a right-of-way for an oil or natural gas pipeline valued at $1,000,000 or more may be granted only upon the condition that the lessee expressly covenants in the lease, in consideration of the rights acquired by it under the lease, that

(1) it assumes the status of and will perform all of its functions undertaken under the lease as a common carrier and will accept, convey, and transport without discrimination crude oil or natural gas, depending on the kind of pipeline involved, delivered to it for transportation from fields in the vicinity of the pipeline subject to the lease throughout its route both on state land obtained under the lease and on other land; however, a lessee who owns or operates a natural gas pipeline subject to regulation either (A) under the Natural Gas Act (15 U.S.C. 717 et seq.) of the United States, or (B) by the state or political subdivisions with respect to rates and charges for the sale of natural gas, is, to the extent of that regulation, exempt from the common carrier requirement in this paragraph; it will accept, convey, and transport crude oil or natural gas without unjust or unreasonable discrimination in favor of one producer or person, including itself, as against another but will take the crude oil or natural gas, depending on the kind of pipeline involved, delivered or offered, without unreasonable discrimination, that the Alaska Pipeline Commission shall, after a full hearing with due notice to the interested parties and a proper finding of facts, determine to be reasonable in the performance of its duties as a common carrier;

(4) restore and revegetate during the term and at termination of the lease; and

(5) protect the interests of individuals living in the general area of the right-of-way who rely on the fish, wildlife, and biotic resources of the area for subsistence purposes.

(e) In the event the commissioner proposes to offer a lease or leases to two or more lessees for the same pipeline, the commissioner may include terms in the lease or leases which establish the limit of the obligations and liabilities of each lessee arising under this chapter or under the lease or leases.

(f) The commissioner may, at his discretion, include any or all of the terms set out in this section in leases of state land for products pipeline right-of-way purposes. (§ 1 ch 72 SLA 1972; am § 11 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.130. Right-of-way easements or leases acquired from others. (a) The lessee may, if the commissioner delegates the function to it, condemn, by declaration of taking, under AS 09.55.420 — 09.55.450, real property and acquire leases of or easements or rights-of-way on lands in the state required for right-of-way purposes for a pipeline subject to the lease on behalf of and as agent for the state in which title to or interest in the land shall vest.

(b) The lease shall contain a covenant that the land, right-of-way, or easement acquired under this section is or will form part of the land leased to the lessee. (§ 1 ch 72 SLA 1972; am § 12 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote subsection (a), deleting the paragraph designations and deleting the provisions of former paragraphs (1) and (2). The amendment also, in subsection (b), substituted "The lease shall contain a covenant" for "The lease covenant required by this section shall be accompanied by a provision" and deleted "carrier" following "lessee."

Quoted in Arco Pipeline Co. v. 3.60 Acres, More or Less, Sup. Ct. Op. No. 1177 (File No. 2419), 539 P.2d 64 (1975).

Sec. 38.35.140. Payment of rental and costs. (a) The lease price for a right-of-way lease shall be the annual fair market rental of the state lands included in the right-of-way based on the appraised fair market value of the land. The lease price is payable annually in advance on or before the anniversary of the lease. The appraised fair market rental value shall be adjusted periodically under the provisions of AS 38.05.015. Rental may not be charged for any land acquired by the lessee under § 130(b) of this chapter and conveyed without cost to the state.

(b) The lessee shall reimburse the state for all reasonable costs incurred in monitoring the construction of the pipeline on the right-of-way. (§ 1 ch 72 SLA 1972; am § 13 ch 3 FSSLA 1973)

re pressurize Swanson Field

Talk with Dale Teel and Paul Robinson

4/14/77

(1) ✓ Need for gas
- Kenai area
- Anchorage
- to ~~commit additional~~ reserves for Anchorage

(2) Price charged by Phillips for transportation + compression
- File for new tariff with APUC?
Will it be approved?

(3) ✓ Copy of map to show

(4) ✓ What are details of Kenai Gas Field? Other contracts APC has for gas over + above the 10 Bcf contract for North Kenai.

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✓ (c) Customers – BLPP + 285 cust?

Used up in 1976

10 Bcf

(1) 550 Bcf — Jan 1 '72 — Kenai A V-M — Gas Field

400 — Remaining presently

Committed to Anchorage

(2) 10 Bcf — for 10 yrs. — May 1, 1967 — Kenai Gas Field V-M

-0- — Used up committed supply June/July 1976

— Extended contract for 1 yr by being supplied out of Kenai Anchorage committed reserves.

4/14/77

Tel conversation with

Bill Hickman / Treasurer
AGIAS
277-8551

① BH felt that if they don't get their royalty gas at the 75¢ (which is apparently the current price for gas to Tokyo) they would have to buy reserves at a higher price elsewhere

② The Bd of Directors of APC did approve the building of a "royalty line" but only after there was no chance that an "exchange" of Kenai / North Cook Inlet gas could be worked out.

③ Such a pipeline would apparently cost $4,000,000

④ Union "charges" APC 1½¢ / Mcf to carry APC's gas in it's

AGO 801272

transmission line from the Kenai gas field to the North Kenai Road area. APUC has waived jurisdiction, but to "make sure" that it continues to do so apparently Union charges this extremely low token transportation charge of APC as a public utility.

(5) Bill Hickman states that it was apparently (at least he thought so) Phillips rather than Union which did not want to see the paper "exchange" of gas from the two fields as proposed by APC, since Phillips would stand to benefit from having APC sell back to it that portion of North Cook Inlet royalty gas they (APC) did not have a market for.

(6) Said he would send me one or more maps tomorrow.

4/14/77

called Sue Knowles at APUC. She was out! talked to Gordon Zerbetz instead.

① He will look at Order 3, U-75-68 to re-familiarize himself with the matter.

② He will send me a complete copy of the Order

③ Asked that I send him cost breakdowns for transportation and compression ~~costs~~ charges Phillips is assessing APC.

④ Gold-streaked Dale Teal's whole packet dated 3/10/77 this pm.

⑤ Will advise me tomorrow about initial reaction. Indicated they would very possibly like to comment on the charges; and

— I asked that we need advice if APUC planned to allow flow through of 10¢ + 10¢ at the time Order No 3, U-75-68 was issued when everyone was still talking about 5.65¢/Mcf for transportation

Question | What is "just and reasonable" in terms of a flow through provision

Board 4-5-76 DK

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 Anchorage, Alaska 99502 / Phone (907) 277-5551
Telex 25-187

April 2, 1976

RECEIVED APR 05 1975
RECEIVED APR - 5 1976
ALASKA ROYALTY OIL & GAS BOARD
Department of Natural Resources

Mr. Bill Fackler, Executive Director
State of Alaska Oil and Gas Royalty Board
Department of Natural Resources
Pouch M
Juneau, AK 99811

Dear Bill:

This is written to furnish you with some background information relating to our past and present "flow through" situations and why we feel that the APUC actions have served to "inhibit" our search for new and probably higher priced non-royalty reserves.

Enclosure A contains our previous "flow through" provision while Enclosure B contains the one presently in effect.

A brief description of the sequence of events leading to the change is as follows:

December 15, 1974 - AGAS agreed to a gas price increase (19.5¢/MCF) to become effective July 1, 1975 in order to obtain gas in the quantities required by its customers. The APUC and major customers were notified in advance of completion of negotiations.

December 20, 1974 - The APUC ordered an investigation and public hearing on the tariff flow through provisions.

March 21, 1975 - AGAS filed new rates giving effect to the increased cost.

April 24, 1975 - The APUC rejected AGAS newly filed rates.

May 2, 1975 - AGAS notified suppliers to not proceed with any investment in workover and/or new wells required to meet its contractual commitments.

May 6, 1975 - The APUC ordered an investigation of the anticipatory breach of contract indicating that it might for good cause shown revoke AGAS certificate of public convenience and necessity.

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P.O. Box 6288 / Anchorage, Alaska 99502

May 8, 1975 - AGAS agreed to withdraw its tariff flow through provisions.

May 12, 1975 - The APUC accepted AGAS tariff filing of March 21, 1975 as an interim request for rate relief and set hearing date of June 19, 1975.

July 1, 1975 - The APUC granted an increase of 12.78¢/MCF.

July 9, 1975 - AGAS requested reconsideration of the July 1, 1975 order.

July 31, 1975 - The APUC denied AGAS request of July 9, 1975.

July 31, 1975 - AGAS filed proposed new cost of gas flow through tariff provisions to replace those withdrawn May 12, 1975.

August 28, 1975 - The APUC suspended the filing of July 31, 1975 and set hearing date of October 30, 1975.

December 17, 1975 - The APUC issued its order modifying the flow through provisions filed July 31, 1975.

AGAS subsequently petitioned for reconsideration of the order of December 17, 1975 and the APUC denied the petition. In addition to the above mentioned actions there have been a series of requests, hearings, and orders relating to AGAS further attempts to recoup its increased costs.

In concept, the idea that a full rate hearing for each fuel cost change is an appropriate means of consumer protection, appears valid. Our actual experience with the process indicates it is not. The following experiences have led us to this conclusion:

(1) Rate cases are expensive and time consuming processes. We have devoted an inappropriate amount of internal time and talent in our year long battle that began with the negotiated gas cost increase. We have spent approximately $320,000 on attorneys and other specialists in regulatory matters in attempting to recover costs incurred by us in good faith for the benefit of our customers. The benefit of hindsight indicates we made a timely and appropriate

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business decision, yet one that has been costly to the owners of the Company. Common sense tells us that a similar occurrence in the future could result in a new management team.

(2) The uncertain outcome of hearings before an appointed regulatory agency with a recent history of rapid change in composition and philosophy makes long term commitments an extremely risky course of action.

A fuel cost flow through provision which would not require the company to assume the burden of proof in a full rate hearing for each fuel cost change would reduce the business risk to an acceptable level. Such provision would not prevent the Commission from ordering rate decreases in instances where the use of the provisions would result in an excessive profit to the utility.

Bill, I hope that this helps to explain our situation and to give you some insight into the constraints under which we labor as we strive to acquire additional reserves.

Very truly yours,

Harold

Harold F. Schmidt
Senior Vice President

HFS:jdh

Enclosures

ENCLOSURE A

PURCHASED GAS COST ADJUSTMENT CLAUSE
WITHDRAWN MAY 12, 1975

708 Purchased Gas Cost Adjustment - Company's rates are based on the current wellhead cost of a firm supply of natural gas at the gas field. In the event this price is increased or decreased, or taxes on such gas are increased or decreased, above the amount(s) payable on April 15, 1972, then the Company may, after appropriate notice to the Alaska Public Utilities Commission as required by AS 42.05.411, place into effect a like increase or decrease in the rate theretofore in effect. Such adjustment shall begin with bills rendered during the month subsequent to the effective date of the increase or decrease at wellhead.

PURCHASED GAS COST ADJUSTMENT CLAUSE
CURRENTLY IN EFFECT

708 Purchased Gas Cost Adjustment - The gas supply contracts existing on December 1, 1975, contain escalation clauses which result in periodic increases or decreases in the cost of purchased gas. Any increase in the cost of purchased gas to the Company under the escalation clauses that the Company becomes responsible for after July 1, 1976, may be passed on to the customers of the Company. Such an increase may be reflected in the rates paid by the customers for gas used by the customer after the date the Company is responsible for paying the increase. The increase, however, may not be charged to the customers of the Company unless the Company meets the conditions specified in Order No. 3 in Docket U-75-68. The Company may not flow through to its customers any increases in the cost of gas resulting from alterations, changes, or amendments of any part of the escalation clauses existing on December 1, 1975. The Company also may not flow through to its customers any other increase in the cost of gas except as specified in this Section and the Royalty Gas Section of this tariff. The increases flowed through to the customers pursuant to this section may not exceed 5¢/MCF per calendar year.

In the event the price which the Company must pay to purchase gas to serve the Company's customers is decreased the Company shall decrease its rates to its customers to fully reflect the entire decrease in the purchased gas cost.

Royalty Gas - The cost of gas purchased from the State is greater than the cost of gas purchased from other suppliers. The gas purchased from the State must be taken by the Company as produced. The Company must therefore distribute this gas to its customers when taken and it must be sold at a higher rate than the gas it now purchases from other suppliers. In order to insure a proper price of gas as a result of the commingling of the higher priced State gas and the lower priced gas from other suppliers the Company shall, month to month, increase or decrease the bills of customers to reflect the average cost per MCF of gas on an MCF basis which shall be computed as the product of the volume of gas purchased from the State each month multiplied by the price of that gas, plus the product of the volume of gas purchased from other suppliers during the month multiplied by the cost of this gas, and the sum of the products thus computed divided by the total volume of gas purchased. The flow through increases or decreases pursuant to this section of the tariff are subject to the conditions set forth in Order No. 3 of Docket U-75-68.

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 Anchorage, Alaska 99502 / Phone (907) 277-5551
Telex 25-187

March 9, 1977

Mr. Don Wold, Executive Director
Royalty Oil & Gas Development
Advisory Board
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Dear Don:

As requested at the meeting of the Board on March 7, I enclose the pertinent extract (pages 1,8,9,10) from Order No. 3 in Docket U-75-68 dated 17 December, 1975.

You will note on page 10 that we were expected to be taking royalty gas prior to August 1, 1976. We explained the status of this matter by letter of September 29, in response to their inquiry. I surely hope that now, nearly 6 months later, we will be able soon to conclude the negotiations and proceed to begin taking royalty gas this year. Clearly, the Commission is convinced of our imperative need to obtain more reserves and has approved flow through of the cost. Copy of the complete order was mailed to the Attorney General, and to each legislator, by the Commission. I believe we will have no difficulty getting approval of the amended contract.

Very truly yours,

Dale Teel

dh

Enclosures: Pages 1,8,9,10 and Mailing List of Order No. 3, U-75-68
Letter to APUC dated September 29, 1976

RECEIVED
MAR 1 1 1977
ALASKA ROYALTY
OIL & GAS BOARD

AGO 801281

STATE OF ALASKA

THE ALASKA PUBLIC UTILITIES COMMISSION

Before Commissioners: Gordon J. Zerbetz, Chairman
B. Richard Edwards
Marvin R. Weatherly
Carolyn S. Guess (not participating)
Susan M. Knowles

In the Matter of the Filing of a Tariff Revision, Designated as TA12-4, by ALASKA GAS AND SERVICE COMPANY to Adopt Purchased Gas and Tax Adjustment Clauses	U-75-68 ORDER NO. 3

ORDER MODIFYING PURCHASED GAS COST AND TAX FLOW THROUGH CLAUSES AND ACCEPTING MODIFIED CLAUSES

On July 31, 1975, ALASKA GAS AND SERVICE COMPANY (AGAS), a division of Alaska Interstate Company, filed a tariff revision to reinstate in its natural gas utility tariff its tariff rules Nos. 708 and 709. These sections would allow AGAS to flow through to its customers, by means of a billing surcharge, any increase in its wellhead cost of gas above 41.5¢ per MCF occurring after July 1, 1975, and any new or increased tax or excise imposed by Federal, State, Borough, Municipal or other local taxing authority upon the production, transmission, or sale of gas, or levies of special taxes, license fees, or street or right-of-way levies or fees, above the amounts established on January 1, 1975.

Order No. 1 in this proceeding suspended the tariff revision until March 1, 1976. In Order No. 1 the Commission also established a hearing date of October 30, 1975. AGAS was to bear the burden of proof that the tariff revision requested was reasonable and proper in all respects.

AGO 801282

will be tailored as much as possible to enable the gas cost increases based on the wholesale price index to be flowed through in a timely manner.

Where a flow through will not result in AGAS maintaining or receiving more than a reasonable rate of return on its investment it is the opinion of this Commission that the flow through should be permitted. The basic reason for flow through provisions is to insure that a short term windfall does not accrue to the customers of AGAS in rates which do not properly reflect the revenue requirements of AGAS. Such a windfall would result from short term regulatory lag. When designing flow through clauses or allowing the flow throughs pursuant to the clauses the Commission must insure that windfall profits do not accrue to AGAS. Each of the flow through clauses acceptable to the Commission should be applied by AGAS with this in mind. Conservative applications of these clauses should be the norm for AGAS. If the Commission determines that the flow through clauses set forth above in this order including the royalty gas clause are being applied to maintain or receive more than a reasonable rate of return or are otherwise being abused the Commission will commence an investigation to repeal these clauses and order appropriate refunds where applicable.

Royalty Gas

The evidence in this proceeding clearly demonstrates that if AGAS is able to purchase royalty gas from the State of Alaska it will be necessary that AGAS take the gas as it is produced and that the price of this royalty gas will be somewhat higher than the price of gas from other gas

AGO 801283

supplies now committed to AGAS. The volume of gas from the State will not meet the entire demand on the system which results in commingling of high and low priced gas. This commingling raises several problems. The initial problem is a month to month change in rates to the consumers of AGAS. The month to month billings would vary directly in accordance with the royalty gas portion of the total gas volume consumed by the customers of AGAS. A higher proportion of royalty gas consumed would result in an increased average cost of gas. In order to prevent a windfall for either AGAS or the customers of AGAS that would result by setting a constant average price, it is the Commission's opinion that the royalty gas may be commingled with the cheaper gas and that the month to month rates of customers of AGAS may vary in accordance with the amount of royalty gas distributed to the customers. Another problem raised with the royalty gas variation involves the conditions under which the royalty gas flow through clause may be used. It is apparent to the Commission that monthly filings of comparative balance sheets, operating expense statements, rate of return calculations and rate base calculations is not practical for the implementation of this clause. It is the Commission's opinion, however, that a report should be filed by AGAS in a form acceptable to the staff of the Commission, that would allow the staff of the Commission to audit the fluctuation of the rates charged for gas to the customers of AGAS. These reports will be due on January 15, April 15, July 15 and October 15 of each year. The information in the report should at least show the total volume of gas consumed for each of the months involved in the report, the volume of

AGO 801284

royalty gas purchased for each month, the price of the royalty gas at the point of purchase by AGAS, and the price and volume of the gas purchased by AGAS from other suppliers.

The method which should be used by AGAS to determine its average cost of gas per MCF is to multiply the amount of State royalty gas purchased in a month times the price of the State royalty gas and add to that product the product of the price and volume of gas purchased from other suppliers in the same month. The sum of the two products should then be divided by the total amount of gas purchased in the month to arrive at the average cost of gas per MCF. It is apparent to the Commission that by using this formula the additional cost of gas per MCF that the customers of AGAS will pay as a result of the commingling of royalty gas with other gas will fall generally in the range of 2 to 5¢ per MCF per month.

It is the Commission's opinion that it is imperative for AGAS to obtain additional reserves and gas supply to serve its customers. If the royalty clause is not used to reflect an average cost of gas on or before August 1, 1976, this Commission will commence an investigation to determine the reasons for the non-use and whether the clause should be deleted from the tariff of AGAS.

RESERVE TAX

The evidence in this proceeding shows that the gas company may become responsible for the payment to its suppliers of gas of the reserve tax that its suppliers are required to pay the State of Alaska pursuant to 159 SLA 1975. It is the opinion of the Commission that this tax should be treated as an expense of the utility recoupable

AGO 801285

Zorbetz - 4/18/77

"It would appear that the flow through charges would be valid."
To develop a new rate case it would require an order of APUC based on a complaint by consumer
citizen
APUC
state agency

AS 42.05 — APUC
almost bound to pass on any bona fide expense/cost a utility incurred

Adverse ruling if it could be shown that APC could have been more "reasonable or prudent"

Zorbetz said it was
— a reasonable price
— difficult to disallow flow through of added costs under present statutes, so long as the charges were bona fide costs.
— public hearing to justify the flow

AGO 801286

through Cts. In order the put the burden of proof on AGAS APUC could not call the hearing.

Mentioned that AGAS was "pretty smug" about the whole thing, but there was nothing improper as far as he could determine off hand.

He also mentioned that he thought the rate of return accdg to the figures submitted by Phillips seems a bit high compared to what APUC is allowing APC.

In response to question as to how something like this could be avoided in the future he mentioned that he had suggested to Dan Wold that Royalty gas Statutes might be revised to allow for a "molecule for molecule" exchange with fields which are more advantageously located to serve the public.

AGO 801287

Zerbetz called around 4/20/77
12:00

Suggested I call and talk to Richard (Dick) D. Edwards who was the author of U-75-68(3).

Zerbetz said he was the "most honest and sincere person" he knew, and that he would be an "impartial source"

Said Ted Smith could provide a reference for Edwards.

AGD 801288

Called Dick Edwards 4/20/77
276-5552

He stated that

- the royalty gas clause was written more to "force" Tul to get out and get committed reserves, rather than addressing itself to the flow through cuts.

- The intent of the order with respect of the royalty prov. was to "beef up APC's reserves which are dwindling, particularly in Anchorage.

- For the public's good - get reserves committed

If we need a legal opinion from him can this matter we can retain him at $80/hr (10-15 hrs preparation time + time in Juneau (8hrs) if nec + expenses -

AGO 801289

travel, hotel, reading, etc- probably a total of 25-30 hrs = $2,500 + expenses — don't use these figures though). He would need a lead time of 2 days

He felt he could give an impartial legal opinion on the matter as long as the Order was not reopened.

AGO 801290

4/22/77

Briefing - Doin N.W/ interested Legislators

— North Cook Inlet Field in the Gulf.

— Contract 76-1 did not become Operational.

— Need to figure out a way to get gas delivered.

— Reasons contract does not work

  — 17mm/day - royalty production/day
  — Must be used within State totally, thus could not resell excess to Phillips
  — Must be taken at wellhead

— By delivering to a utility PU would subject itself to PUC jurisdiction.

① Who did you talk to at the PUC regarding the above? GZ

— PUC is not involved which they should be (check and audit costs; whether they are proper; they did

AGO 801291

not have an opportunity to do so).

- Are the costs reasonable? They have not been looked at; they are negotiated numbers (10 + 10)

Teel: "These costs are reasonable"

analysis of Teel's re these charges

- The charges have not received the scrutiny they would have normally.

- Best Efforts
  - Cannot take all of the time (APC)
  - Cannot produce all of the time. (Pk)

(2) What will happen when APC has its own royalty line?

(3) Why is a 5 yr contract not feasible?

(4) Where is the gas for $1.45? Teel - Beluga; not comparable to NCI royalty sale contract. World - Kenai; Spot sale.

AGO 801292

(5) What did you say was the "average" increase which you mentioned to Rick Union?
Tell - 1¢/gallon/oil for transportion (10¢)

~

1¢/gallon/oil = 7.4¢/Mcf/gas

42 gallons = 1 bbl
1MM BTU/Mcf
5.8 MM BTU/bbl

~

Hugh Malone - 2/3 available to BLPP - Tell cost to BLPP? 86¢ - field to mkt.

AGO 801293

5/6/77

Senate Resources
SCR 56 - North Cook Inlet Royalty Sale

✓(1) charges - APUC
✓(2) Highest Price Argument
✓(3) Length of Contract - Royalty Share

5/7/77

Senate Resources
SCR 56 - NCI Royalty Sale

AGO 801294

5/7/77

BRIEFLY,

APC NEEDS NEW SUPPLIES OF GAS TO CONTINUE SERVICE TO ITS NORTH KENAI ROAD CUSTOMERS AND TO OBTAIN APDITIONAL RESERVES FOR ANCHORAGE.

APC MADE APPLICATION FOR ROYALTY GAS FROM THE NORTH COOK INLET FIELD IN AUGUST 1975, EXPECTING THAT THEY WOULD BE ALLOWED TO FLOW THROUGH THE HIGHER COST OF THE ROYALTY GAS FROM THE NORTH COOK INLET GAS FIELD VIS-A-VIS THEIR KENAI FIELD PRICE.

AT THAT TIME THE PRICE WAS THOUGHT TO BE 50.45¢--45¢ FOR THE GAS AND 5.45¢ FOR TRANSPORTING IT FROM THE PLATFORM TO PHILLIPS' LNG PLANT.

THE APUC ALLOWED FLOW THROUGH OF COST OF THIS HIGHER PRICE ROYALTY GAS IN DECEMBER 1975 WHEN THESE COSTS, TO THE BEST OF OUR KNOWLEDGE, WERE THOUGHT TO HAVE BEEN NO MORE THAN 55.80¢ (50.25¢ FOR THE GAS AND 5.55¢ FOR TRANSPORTATION). THIS COMPARES TO 41.5¢ FOR KENAI FIELD GAS APC HAS UNDER CONTRACT.

NOW, WE ARE TALKING ABOUT 84.65¢ FOR THIS GAS. MOST OF THE ADDED INCREASE IS TAKEN UP BY THE 20¢ FOR TRANSPORTATION AND COMPRESSION. IT IS MAYBE WORTH NOTING THAT THE APUC HAD DENIED APC THEIR TARIFF FLOW THROUGH REQUEST OF 19.5¢ IN APRIL OF 1975, BECAUSE IT WAS SO BROAD AS TO ALLOW ALL COSTS TO BE FLOWED THROUGH, A SITUATION NOT DESIRED BY THE APUC.

WE MENTION THIS ONLY TO POINT OUT THAT IT APPEARS THAT THE APUC WAS APPARENTLY THINKING OF MUCH LOWER COSTS WHEN THEY ALLOWED THESE FLOW THROUGH CHARGES THAN ARE BEING PROPOSED NOW.

AGO 801295

MR. WOLD INDICATED ON FRIDAY THAT APC WOULD GO TO THE APUC TO SEEK APPROVAL OF THESE ADDED TRANSPORTATION AND COMPRESSION COSTS. THIS IS NOT SO!!!!! APC ON TWO OCASSIONS INDICATED TO ME THAT THEY FELT THE DEC. '75 ORDER ALLOWING FLOW THROUGH OF ROYALTY GAS COSTS DID NOT REQUIRE THEM TO SEEK ADDITIONAL APPROVAL FROM THE APUC TO JUSTIFY THE 20¢ TRANSPORTATION AND COMPRESSION CHARGES, AND THAT THEY DID NOT PLAN TO SUBMIT THEM FOR APPROVAL TO THE APUC.

COMMISSIONER ZERBETZ OF THE APUC TOLD ME THAT A CURSORY REVIEW OF THE DECEMBER '75 ORDER WOULD CONFIRM APC'S CONTENTION.

THE CONTRACT BEFORE THE LEGISLATURE NOW SEEKS TO ACCOMMODATE APC SO AS TO ALLOW THEM TO TAKE THE ROYALTY GAS.

THE MAJOR DEVIATIONS ARE --

-- THE DELIVERY POINT

-- THE AMOUNT OF GAS APC IS REQUIRED TO TAKE OF THE ROYALTY PRODUCTION.

APPENDIX "A" ATTACHED TO THE PACKET YOU HAVE COMPARES THE KEY PROVISION OF THE CONTRACTS, AND IF YOU WANT ME TO I CAN QUICKLY GO THROUGH THESE PROVISIONS??????????????

ANOTHER POINT WORTH MENTIONING, I THINK, IS THAT THE APUC ALLOWED THE FLOW THROUGH PROVISIONS TO PROVIDE APC THE OPPORTUNITY FOR SECURING ADDITIONAL GAS RESERVES, PARTICULARLY IN ANCHORAGE. WITH THE ABSENCE OF A ROYALTY LINE AND NO EXCHANGE AGREEMENT BETWEEN APC AND PHILLIPS AND U-M, THE ANCHORAGE DEDICATED RESERVES WILL CONTINUE TO DWINDLE SINCE NO ROYALTY GAS FROM THE NORTH COOK INLET FIELD WOULD REACH ANCHORAGE. THE QUESTION IS WOULD THE APUC HAVE APPROVED THE FLOW THROUGH PROVISIONS AS THEY DID IF THEY HAD KNOWN THAT NO NORTH COOK INLET ROYALTY GAS WOULD REACH ANCHORAGE??????????

MR. WOLD ALSO INDICATED LAST FRIDAY THAT ONE OF THE REASONS THE SALE OF ROYALTY GAS FROM THE NORTH COOK INLET FIELD TO APC WAS IN THE BEST INTEREST OF THE STATE WAS THE PRICE OF THE ROYALTY GAS. THAT IF APC COULD NOT OBTAIN THIS GAS THEY WOULD HAVE TO PAY THE CURRENT GOING PRICE FOR COOK INLET GAS, WHICH IS SAID TO BE AS HIGH AS $1.45. THOSE COSTS, OF COURSE, WOULD BE PASSED ON TO THE CONSUMER AND WOULD BE MUCH MORE THAN ANYTHING PROPOSED BY THE CONTRACT UNDER CONSIDERATION. WHAT MR. WOLD DID NOT SAY WAS THAT THE CONTRACT PROVIDES THAT THE CONTRACT PROVIDES THAT THE CONTRACT PRICE IS RENEGOTIATED ANNUALLY, AND APC WILL HAVE TO PAY THE HIGHEST PRICE OF THREE PRICING OPTIONS. ONE OF THESE OPTIONS IS THE HIGHEST PRICE PAID BY ANY PURCHASER WITHIN A 100 KM RADIUS OF PHILLIPS' PLATFORM FOR SIMILAR QUALITY GAS AND UNDER SIMILAR CONDITIONS OF DELIVERY. THE $1.45 FIGURE INCIDENTALLY IS WITHIN THAT 100 KM RADIUS, WE ARE TOLD.

THEREFORE, IT APPEARS THAT IF PRICES REMAIN WERE THEY ARE AT NOW, OR RISE AS CAN BE EXPECTED, APC WOULDHAVE TO PAY THE HIGHEST PRICE PAID BY ANY PURCHASER WITHIN A YEAR, AND THUS ANY PRICE ADVANTAGE WOULD BE FOREGONE WITHIN ONE YEAR.

WHEN I RAISED THIS POINT WITH MR. TEEL OF APC HE INFORMED ME THAT THERE WOULD NEVER BE A SALE UNDER SIMILAR CONDITIONS AS THE ONE NOW BEING CONSIDERED, AND THUS THEY WOULD NEVER HAVE TO PAY THAT PRICE. IF THAT IS TRUE, I WONDER WHY THE PROVISION EXISTS IN THE CONTRACT?????????

HCR 58

Afternoon session
5/26/77

Rep. Lisa Rudd: Question re the term of the contract

Rep. Hugh Malone: (Speaking from the floor of the House)

"...We have been informed by Mr. Wold, the executive director of the State Royalty Oil and Gas Board, that before such an extension goes into effect the normal course of action would be to ask for that to be ratified by the legislature and so in answer to Rep. Rudd's question (is) initially 1984; following that any extensions are approved by the Administration and, hopefully, by the Legislature."

HCR 58

SCR 56

HB 461 Senator Colletta moved and asked unanimous consent that the Rules be suspended and HOUSE BILL NO. 461 be advanced to third reading and placed on final passage. Without objection, it was so ordered.

HOUSE BILL NO. 461 was read the third time.

The question being: "Shall HOUSE BILL NO. 461 (Extending term of Bristol Bay Regional Development Council) pass the Senate?" The roll was taken with the following result:

Yeas:	18	Bradley, Butrovich, Colletta, Croft, Ferguson, Hackney, Hohman, Kerttula, Meland, Poland, Rader, Ray, Rodey, Sackett, Sumner, Tillion, Willis, Ziegler
Nays:	1	Huber
Excused:	1	Orsini

and so HOUSE BILL NO. 461 passed the Senate.

Senator Colletta moved and asked unanimous consent that the roll call on the passage of the above bill be considered the roll call on the effective date clause. Without objection, it was so ordered.

HOUSE BILL NO. 461 was signed by the PPesident and Secretary and returned to the House.

SECOND READING OF HOUSE RESOLUTIONS

HCR 58 HOUSE CONCURRENT RESOLUTION NO. 58 (Approving disposal to Alaska Pipeline Company of royalty gas taken in-kind) was read the second time.

Senator Sackett moved and asked unanimous consent that the Letter of Intent (Senate Supplement No. 49) be adopted as the Letter of Intent of the Senate. Senator Croft objected.

The question being: "Shall the Finance Committee Letter of Intent be adopted as the Letter of Intent of the Senate?" The roll was taken with the following result:

Yeas:	12	Bradley, Butrovich, Colletta, Hackney, Huber, Meland, Poland, Rader, Sackett, Sumner, Willis, Ziegler
Nays:	4	Croft, Kerttula, Ray, Tillion
Absent:	3	Ferguson, Hohman, Rodey
Excused:	1	Orsini

and so, the Letter of Intent was adopted as the Letter of Intent of the Senate.

Letter of Intent of the Senate appears in Senate Supplement No. 50 to today's journal. HCR 58

Senator Colletta moved for the adoption of HOUSE CONCURRENT RESOLUTION NO. 58.

The question being: "Shall HOUSE CONCURRENT RESOLUTION NO. 58 (Approving disposal to Alaska Pipeline Company of royalty gas taken in-kind) pass the Senate?" The roll was taken with the following result:

Yeas:	12	Bradley, Butrovich, Colletta, Ferguson, Hackney, Meland, Rader, Sackett, Sumner, Tillion, Willis, Ziegler
Nays:	6	Croft, Huber, Kerttula, Poland, Ray, Rodey
Absent:	1	Hohman
Excused:	1	Orsini

and so, HOUSE CONCURRENT RESOLUTION NO. 58 passed the Senate was signed by the President and Secretary and returned to the House.

The President stated the Senate would recess to a call of the Chair. Without objection, the Senate recessed at 3:16 p.m.

AFTER RECESS

The Senate reconvened at 4:35 p.m.

The President stated engrossment on SENATE COMMITTEE SUBSTITUTE FOR COMMITTEE SUBSTITUTE FOR HOUSE BILL NO. 264 (Res) amended Senate be waived in order to transmit the bill to the House as soon as possible. Without objection, it was so ordered. SCS CSHB 264 (Res) am S

UNFINISHED BUSINESS

Senator Kerttula gave notice of reconsideration of SENATE COMMITTEE SUBSTITUTE FOR COMMITTEE SUBSTITUTE FOR HOUSE BILL NO. 264 (Res) amended Senate (Fisheries enhancement) and asked that it be taken up at this time.

Mr. Miller moved and asked unanimous consent that HCS SB 226 (2d Rules) be considered engrossed, advanced to third reading and placed on final passage. There being no objection, it was so ordered; the bill was read the third time. HCS SB 226 (2d Rls)

The question being: "Shall HCS SB 226 (2d Rules) pass the House?" The roll was taken with the following result:

Yeas:	24	Bennett, Bradley, Brown, Buchholdt, Carpenter, Cotten, Cowper, Dankworth, Duncan, Eliason, Gruening, Kelly, Lethin, McKinnon, Malone, Meekins, Miles, Miller, Parr, Phillips, Rudd, Smith, Snider, Urion.
Nays:	16	Akers, Anderson, Beirne, Chatterton, Freeman, Gardiner, Guy, Haugen, Hayes, Lovseth, Nakak, Ose, Osterback, Rhode, Schaeffer, Swanson.
Excused:	0	

And so, HCS SB 226 (2d Rules) passed the House.

Mr. Miller moved that the effective date clause be adopted.

The question being: "Shall the effective date clause be adopted?" The roll was taken with the following result:

Yeas:	36	Akers, Anderson, Beirne, Bennett, Bradley, Brown, Buchholdt, Carpenter, Chatterton, Cotten, Cowper, Dankworth, Duncan, Eliason, Gardiner, Gruening, Haugen, Hayes, Kelly, Lethin, Lovseth, McKinnon, Malone, Meekins, Miles, Miller, Ose, Osterback, Parr, Phillips, Rhode, Rudd, Smith, Snider, Swanson, Urion.
Nays:	4	Freeman, Guy, Nakak, Schaeffer.
Excused:	0	

And so, the effective date clause was adopted.

SECOND READING OF HOUSE RESOLUTIONS

HOUSE CONCURRENT RESOLUTION NO. 58 (approving the disposal of Alaska Pipeline Company of royalty gas taken in-kind) was read the second time with the Resources Committee report (p. 1052) and the Finance Committee report (p. 1304 of the Journal). HCR 58

Speaker pro tempore Miller assumed the Chair.

Mr. Malone voted at Mr. Miller's desk and Mr. Miller voted at the Speaker's desk.

AGO 801303

HCR 58 The question being: "Shall HCR 58 pass the House?" Roll call was requested and appears as follows:

Yeas:	33	Akers, Anderson, Beirne, Bennett, Carpenter, Chatterton, Cotten, Dankworth, Duncan, Eliason, Freeman, Gardiner, Guy, Hayes, Kelly, Lethin, Lovseth, Malone, Meckins, Miles, Miller, Nakak, Ose, Osterback, Parr, Phillips, Rhode, Rudd, Schaeffer, Smith, Snider, Swanson, Urion.
Nays:	4	Bradley, Brown, Buchholdt, McKinnon.
Excused:	3	Cowper, Gruening, Haugen.

And so, HCR 58 passed the House.

Mr. Malone gave notice of reconsideration of his vote on HCR 58.

Mr. Malone moved and asked unanimous consent that the House adopt the letter of intent on HCR 58.(page 1526 of the journal)

Mr. Brown objected and withdrew his objection.

Mr. Bradley objected.

The question being: "Shall the letter of intent on HCR 58 be adopted?" Roll call was requested and appears as follows:

Yeas:	37	Akers, Anderson, Beirne, Bennett, Bradley, Brown, Buchholdt, Carpenter, Chatterton, Cotten, Dankworth, Duncan, Eliason, Freeman, Gardiner, Guy, Hayes, Kelly, Lethin, Lovseth, McKinnon, Malone, Meekins, Miles, Miller, Nakak, Ose, Osterback, Parr, Phillips, Rhode, Rudd, Schaeffer, Smith, Snider, Swanson, Urion.
Nays:	0	
Excused:	3	Cowper, Gruening, Haugen.

And so, the motion passed.

Mr. Malone asked to take up the reconsideration of his vote on HCR 58 at this time.

The question to be reconsidered is: "Shall HCR 58 pass the House?" The roll was taken with the following result:

Yeas:	31	Akers, Anderson, Beirne, Bennett, Chatterton, Cotten, Dankworth, Duncan, Eliason, Freeman, Gardiner, Guy, Hayes, Kelly, Lethin, Lovseth, Malone, Meekins, Miles, Miller, Nakak, Ose, Osterback, Parr, Phillips, Rhode, Rudd, Schaeffer, Smith, Swanson, Urion.
Nays:	3	Bradley, Brown, McKinnon.

AGO 801304

Excused: 6 Buchholdt, Carpenter, Cowper, Gruening, Haugen, Snider. HCR 58

And so, HCR 58 passed the House on reconsideration of the vote and was referred to the Chief Clerk for engrossment.

Speaker Malone resumed the Chair.

Mr. Chatterton gave notice of reconsideration of his vote on HCS CSSB 226 (2d Rules). HCS CSSB 226 (2d Rls)

Mr. Nakak asked that the members of the Conference Committee on HCS CSSB 150 be excused for a meeting in Senator Bradley's office at this time.

HOUSE CONCURRENT RESOLUTION NO. 79 (cost analysis of keeping the capital in Juneau) was read the second time with the State Affairs Committee report (page 1513 of the journal). HCR 79

A fiscal note on HCR 79 appears in House Supplement No. 70.

Mr. Anderson moved that HCR 79 be shown as sponsored by all members of the House.

Mr. Anderson withdrew his motion and moved that his name and other members desiring of having their names added, be added as co-sponsors of HCR 79. There being no objection, it was so ordered.

Mr. Miller moved and asked unanimous consent that the House recess for ten minutes. There being no objection, the House recessed at 2:55 p.m.

AFTER RECESS

The House was called to order at 3:27 p.m.

Mr. Parr moved and asked unanimous consent that the following letter of intent be concurred in by the members of the House and that it be printed in the journal. There being no objection, it was so ordered, and the letter of intent appears as follows:

Letter of Intent on HCR 79

It is the intent of the House that the fiscal note for HCR 79 be zero, and that the cost be absorbed in the authorized budget for the New Capital Site Planning Commission.

HCR 58 The letter of intent on HOUSE CONCURRENT RESOLUTION NO. 58 (approving the disposal to Alaska Pipeline Company of royalty gas taken in-kind) appears as follows:

RULES COMMITTEE

LETTER OF INTENT

The House of Representatives in approving the sale of state royalty gas from the North Cook Inlet field to Alaska Pipeline Company through HCR 58, does not intend to waive, in any way, jurisdiction or regulatory authority of the state over Phillips pipeline or pipelines of a similar nature, and that approval of HCR 58 not be considered as a precedent for any royalty oil or gas sales. The House is concerned by the lack of regulatory review of the tariff charges which would be applicable under the contract.

The House therefore respectfully requests that the Governor, before the state enters into any similar contracts, review the statutes relating to state regulatory authority over pipelines used to transport state royalty oil and gas, including the consideration whether such lines should be designated as common carriers, and to report his findings and recommendations to the Second Session of the Tenth Alaska Legislature within thirty days of convening.

In addition to this, there is a question as to whether all the consumers who will be receiving benefits of the royalty gas will fairly share in the costs. Therefore, the Alaska Public Utilities Commission is respectfully requested to review its 1975 decision relating to flow-through costs of royalty gas.

Finally, although an argument for approval of the contract is certainly to increase the reserves available to both the Kenai Peninsula and Anchorage, it appears that either construction of a new line or an exchange agreement with Union Marathon is necessary to make the reserves usable. Therefore, the Alaska Public Utilities Commission is respectfully requested to review its 1971 exemption from regulation of the Kenai-Nikiski gas pipeline.

Samuel R. Cotten

Rep. Sam Cotten, Chairman
House Rules Committee

T Buchholdt
Rep. Buchholdt, Vice Chmn

Rep. Miller

Rep. Urion

Rep. Parr

Tim Kelly
Rep. Kelly

Rep. Nakak

AGO 801306

CSHB 342 am A message dated May 10, 1977 was read stating the Senate has passed COMMITTEE SUBSTITUTE FOR HOUSE BILL NO. 342 amended (management of the coastal resources of the state; effective date) with the following amendment:

SENATE COMMITTEE SUBSTITUTE FOR
COMMITTEE SUBSTITUTE FOR HOUSE BILL NO. 342

and the same is transmitted for consideration.

REPORTS OF STANDING COMMITTEES

HCR 58 The Finance Committee has had HOUSE CONCURRENT RESOLUTION NO. 58 (approving the disposal to Alaska Pipeline Company of royalty gas taken in-kind) under consideration and five of the members recommend it do pass. Concurring: Freeman (Vice Chairman), Rhode, Haugen, Guy and Duncan. Not concurring: Gruening, Buchholdt and Meekins have no recommendation.

HCR 58 was referred to the Rules Committee for placement on the calendar.

HCR 59 The Finance Committee has had HOUSE CONCURRENT RESOLUTION NO. 59 (approving the disposal to Golden Valley Electric Association, Inc. of royalty oil taken in-kind) under consideration and a majority of the members recommends it do pass. Concurring: Freeman (Vice Chairman), Gruening, Duncan, Buchholdt, Guy, Haugen and Rhode. Not concurring: Meekins has no recommendation.

HCR 59 was referred to the Rules Committee for placement on the calendar.

CSHB 322 A Finance Committee Chairman's letter of intent on CSHB 322 appears as follows: (The Finance Committee report appears on page 1284 of the journal.)

FINANCE COMMITTEE CHAIRMAN'S REPORT
FOR
COMMITTEE SUBSTITUTE
FOR
HOUSE BILL NO. 322

The House Finance Committee reports out CSHB 322, an oil and gas corporate franchise tax, which includes as additions to the original bill, HB 322, the following provisions:

1. A requirement that the tax be paid even though it be challenged before the department or under appeal in the courts (Sec. 43.21.060(1)); and

2. Relief for the taxpayer if the taxpayer can establish that it is being taxed on more than 100% of its net income (Sec. 43.21.065).

MESSAGES FROM THE SENATE

HCR 53 A message dated April 27, 1977 was read stating the Senate has passed HOUSE CONCURRENT RESOLUTION NO. 53 (Alaska Special Olympics), and it is returned.

HCR 53 was referred to the Chief Clerk for enrollment.

A message dated April 28, 1977 was read stating the Senate accepts the invitations to joint sessions April 28, 1977, Thursday at 1:30 p.m. for the purpose of confirmation of the Governor's appointments and for changes to the Uniform Rules; and April 29, Friday at 1:30 p.m. for the purpose of d-2 land discussions with the Honorable Ted Stevens, U.S. Senator, and the Governor of Alaska.

HCR 50 A message dated April 27, 1977 was read stating the Senate has passed HOUSE CONCURRENT RESOLUTION NO. 50 (commending the State Investment Advisory Committee) with the following amendment:

Page 1, line 23: After "Sterling" delete "S"

Page 2, line 2: After "Sterling" delete "S"

and so, HOUSE CONCURRENT RESOLUTION NO. 50 amended Senate is transmitted herewith for consideration.

REPORTS OF STANDING COMMITTEES

SCR 26 The Judiciary Committee has had SENATE CONCURRENT RESOLUTION NO. 26 (increase in the number of state troopers) under consideration and a majority of the members recommends it be replaced with HOUSE COMMITTEE SUBSTITUTE FOR SENATE CONCURRENT RESOLUTION NO. 26 (same title) and that it do pass. Concurring: Gardiner (Chairman), Miles, Eliason and Brown.

SCR 26 was referred to the Finance Committee.

HCR 58 The Resources Committee has had HOUSE CONCURRENT RESOLUTION NO. 58 (approving the disposal to Alaska Pipeline Company of royalty gas taken in-kind) under consideration and a majority of the members recommends it do pass. Concurring: Osterback (Chairman), Eliason, Smith, Urion and Akers. Not concurring: Snider and Malone have no recommendation.

HCR 58 was referred to the Finance Committee.

Introduced: 4/22/77
Referred: Resources

IN THE SENATE

BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

SENATE CONCURRENT RESOLUTION NO. 56

IN THE LEGISLATURE OF THE STATE OF ALASKA

TENTH LEGISLATURE - FIRST SESSION

Approving the disposal to Alaska Pipeline Company of royalty gas taken in-kind

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS, under AS 38.06.055(a), each house of the legislature must approve by concurrent resolution all sales of state-owned royalty natural gas before the sale may be consummated; and

WHEREAS the State of Alaska has the right under AS 38.05.180 and its oil and gas leases to receive royalty natural gas either in-kind or in-value from fields in the Cook Inlet area; and

WHEREAS the commissioner of natural resources has entered into a contract for the sale of state-owned royalty natural gas from the North Cook Inlet Field to Alaska Pipeline Company; and

WHEREAS the Alaska Royalty Oil & Gas Development Advisory Board approved the contract for the sale of royalty natural gas from the North Cook Inlet Field to Alaska Pipeline Company; and

WHEREAS the legislature has reviewed this contract and conducted hearings and otherwise received public input on this contract; and

WHEREAS the legislature finds this contract to be in the public interest of Alaska and its people, and further finds that this contract is in compliance with all requirements of law;

BE IT RESOLVED by the Alaska State Legislature that the "Gas Purchase Contract" dated April 11, 1977, with the Alaska Pipeline Company and the commissioner of natural resources for the sale and purchase of royalty natural gas from the North Cook Inlet Field is hereby approved.

AGO 801309

Introduced: 4/22/77
Referred: Resources and Finance

IN THE HOUSE

BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

HOUSE CONCURRENT RESOLUTION NO. 58

IN THE LEGISLATURE OF THE STATE OF ALASKA

TENTH LEGISLATURE - FIRST SESSION

Approving the disposal to Alaska Pipeline Company of royalty gas taken in-kind

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS, under AS 38.06.055(a), each house of the legislature must approve by concurrent resolution all sales of state-owned royalty natural gas before the sale may be consummated; and

WHEREAS the State of Alaska has the right under AS 38.05.180 and its oil and gas leases to receive royalty natural gas either in-kind or in-value from fields in the Cook Inlet area; and

WHEREAS the commissioner of natural resources has entered into a contract for the sale of state-owned royalty natural gas from the North Cook Inlet Field to Alaska Pipeline Company; and

WHEREAS the Alaska Royalty Oil & Gas Development Advisory Board approved the contract for the sale of royalty natural gas from the North Cook Inlet Field to Alaska Pipeline Company; and

WHEREAS the legislature has reviewed this contract and conducted hearings and otherwise received public input on this contract; and

WHEREAS the legislature finds this contract to be in the public interest of Alaska and its people, and further finds that this contract is in compliance with all requirements of law;

BE IT RESOLVED by the Alaska State Legislature that the "Gas Purchase Contract" dated April 11, 1977, with the Alaska Pipeline Company and the commissioner of natural resources for the sale and purchase of royalty natural gas from the North Cook Inlet Field is hereby approved.

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AGO 801310

CONTRACTS

APPENDIX "A"

KEY PROVISIONS

	CONTRACT 76-1	PROPOSED REVISED CONTRACT CONTRACT BETWEEN STATE AND PHILLIPS (with APC being a signatory)	CONTRACT BETWEEN STATE AND APC
Quantity:	ARTICLE II All royalty gas available, when and as available.	ARTICLE IV 1. Phillips shall use its "best reasonable efforts" to deliver not less than 3 Bcf of royalty gas annually (without requiring installation or operation of added pipeline and compression facilities), and subject to a. availability of capacity in Phillips' facilities to handle volumes in excess of Phillips' own requirements; b. availability of royalty gas at the platform; c. APC's requirements; and d. APC's ability to take the requirements. 2. Over or under deliveries of royalty gas shall be carried in an over and short account. In the event the takes by the State (APC) shall ever be 60 MMcf less than the amount of royalty gas available, Phillips shall purchase the excess undelivered quantities of royalty gas over 60 MMcf from the State, and pay the State a price equal to that amount which Phillips would have otherwise paid the State had the State taken its royalty gas in value.	ARTICLE III 1. Up to all royalty gas available, subject to a. APC's ability to take the entire amount of royalty gas available on any given day; b. APC's need and available delivery facilities. APC shall use its "best reasonable efforts" to take not less than 3 Bcf of royalty gas annually. 2. Over or under deliveries of royalty gas shall be carried in an over and short account. In the event the takes by APC shall ever be 60 MMcf less than the amount of royalty gas available APC is not permitted to make up for any such underdelivery and the State may sell the undelivered quantity of royalty gas to Phillips.
Delivery Point:	ARTICLE III Delivery point shall be the same for APC as it has been for State, which is Phillips' platform.	ARTICLE III & V Delivery point shall be at or near the existing pipeline tap being presently used to deliver gas from Phillips' pipeline to the Tesoro refinery, which is located in the general vicinity of Phillips' Kenai LNG plant on the North Kenai Road.	ARTICLE V APC's connection into Phillips' pipeline system at or near Phillips' pipeline tap serving the Tesoro refinery. It shall be the same delivery point as that of the State and Phillips.
Price:	ARTICLE V 1. To July 1, 1977 55.5¢/Mcf 2. July 1, 1977-July 1, 1978 the higher of a. 60.36¢/Mcf or b. price State would have received had it continued to take its royalty gas in value or c. the highest price paid by any purchaser in the Upper Cook Inlet area (within a 100 km radius of Phillips' platform) for similar quality gas and similar conditions of delivery. 3. July 1, 1978 and each succeeding 12 month period the higher of a. the previous year's price plus 2¢/Mcf or b. price State would have received had it continued to take its royalty gas in value or c. the highest price paid by any purchaser in the Upper Cook Inlet area (within a 100 km radius of Phillips' platform) for similar quality gas and similar conditions of delivery.		ARTICLE VI 1. To July 1, 1978 64.65¢/Mcf 2. July 1, 1978-July 1, 1979 the higher of a. 66.65¢/Mcf or b. price State would have received had it continued to take its royalty gas in value or c. the highest price paid by any purchaser in the Upper Cook Inlet area (within a 100 km radius of Phillips' platform) for similar quality gas and similar conditions of delivery. 3. July 1, 1979 and each succeeding 12 month period the higher of a. the previous year's price plus 2¢/Mcf or b. price State would have received had it continued to take its royalty gas in value or c. the highest price paid by any purchaser in the Upper Cook Inlet area (within a 100 km radius of Phillips' platform) for similar quality gas and similar conditions of delivery.

AGO 801312

	CONTRACT 76-1	CONTRACT BETWEEN STATE AND PHILLIPS	CONTRACT BETWEEN STATE AND APC
Gathering and Compression Charges and Taxes; Other Charges		ARTICLE IX 1. 10¢/Mcf for gathering costs to delivery point to increase 6 percent per year compounded annually on the anniversary date of the contract. 2. 10¢/Mcf for added compression costs to delivery point to increase 6 percent per year compounded annually on the anniversary date when the facilities were first used. 3. Additional compression charges to be mutually agreed upon between the parties, which includes APC since they are signatories of this contract (see also 12.3). If no agreement is reached within 90 days after Phillips serves notice about such added costs, then this contract is terminated. 4. Additionally, the State must pay Phillips any new or increased fee, imposts, duty, charge, excise or tax in proportion to the amount of royalty gas delivered to the State as it relates to gathering and compression.	ARTICLE VI & VII 1. 10¢/Mcf for gathering costs to delivery point to increase 6 percent per year compounded annually on the anniversary date of the contract. 2. 10¢/Mcf for added compression costs to delivery point to increase 6 percent per year compounded annually on the anniversary date when such compression facilities are ready for use. (This is different from State/Phillips agreement.) This does not obligate Phillips to install any compression facilities or to operate any compression facilities already installed. 3. Additional compression charges to be mutually agreed upon between the State and APC. If no agreement is reached within 90 days after the State serves notice about such added costs, then this contract is terminated (7.5). 4. APC must pay the State any amount for which the State is obligated to reimburse Phillips for a proportion of new or increased fees, imposts, duties, charges or taxes. (This leaves out excise.) (The language is somewhat different from State/Phillips contract, but the effect would seem to be the same.) 5. APC must pay the State any additional costs not covered in the contract and incurred by State in transporting the gas to shore.
Term:	ARTICLE VI Effective: Upon approval by the Legislature 5/20/76 Expiration: July 1, 1984	ARTICLE XIV Effective: Upon approval by the Legislature of the contract between the State and APC. Expiration: June 1, 1984 unless terminated or extended prior to that date.	ARTICLE VII Effective: Upon approval by the Legislature. Expiration: June 1, 1984 unless terminated or extended prior to that date.
Termination Clause:	ARTICLE VII Allows APC to terminate the contract within 30 days of written notice to State if APC is unable to make satisfactory arrangements to take delivery of the royalty gas. APC may not exercise this right after January 31, 1978.	ARTICLE IX, XI & XIV 1. Will be terminated immediately if deliveries to State (APC) have not commenced by June 30, 1978. 2. If subjected to regulation as a utility (11.2). 3. If added compression cost cannot be agreed upon within 90 days (9.3). 4. If contract between State and APC is terminated. 5. If terminated the State's election to receive its royalty gas in-kind is revoked, and royalty gas available shall be sold to Phillips in value. 6.	ARTICLE VII 1. Contract shall terminate immediately if deliveries to APC have not commenced by June 30, 1978. 2. Either State or APC may terminate this contract by giving 30 days notice to the other if Phillips comes under regulation as a utility. 3. Contract may be terminated if added compression cost cannot be agreed upon within 90 days. 4. Contract may be terminated if contract between State and Phillips is terminated. 5. 6. State may terminate upon 30 days notice to APC if the State cannot arrange for satisfactory transportation of royalty gas to shore.

AGO 801313

CONTRACT 76-1	CONTRACT BETWEEN STATE AND PHILLIPS	CONTRACT BETWEEN STATE AND APC
Representation and Condition Precedent:	ARTICLE XI Phillips, by entering into this contract, shall not be subject to regulation by the FPC, APUC or APC. Should they become subject to regulation as a utility this contract may be terminated by either party upon 30 days' notice.	ARTICLE VIII Neither this contract nor APC's use or disposition of the royalty gas will subject Phillips to FPC, APUC or APC regulation.
Payments:	ARTICLE XII APC to make all payments for State's account directly to Phillips.	
Miscellaneous		ARTICLE IX 1. Assignments of interest by APC may be made "...to conform with...(APC's) various financing documents or as may be desirable to...(APC) as to...(APC's) commonly owned affiliate or subsidiary." 2. If APC does not receive or purchase all royalty gas available, then State can dispose of that portion not taken, provided no gathering and compression charges are incurred by APC as a result.

AGO 801314

W.O. 41105

Introduced: 4/22/77
Referred: Resources and Finance

IN THE HOUSE SCR No 58 BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

HOUSE CONCURRENT RESOLUTION NO. 58

IN THE LEGISLATURE OF THE STATE OF ALASKA

TENTH LEGISLATURE - FIRST SESSION

Approving the disposal to Alaska Pipeline Company of royalty gas taken in-kind

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS, under AS 38.06.055(a), each house of the legislature must approve by concurrent resolution all sales of state-owned royalty natural gas before the sale may be consummated; and

WHEREAS the State of Alaska has the right under AS 38.05.180 and its oil and gas leases to receive royalty natural gas either in-kind or in-value from fields in the Cook Inlet area; and

WHEREAS the commissioner of natural resources has entered into a contract for the sale of state-owned royalty natural gas from the North Cook Inlet Field to Alaska Pipeline Company; and

WHEREAS the Alaska Royalty Oil & Gas Development Advisory Board approved the contract for the sale of royalty natural gas from the North Cook Inlet Field to Alaska Pipeline Company; and

WHEREAS the legislature has reviewed this contract and conducted hearings and otherwise received public input on this contract; and

WHEREAS the legislature finds this contract to be in the public interest of Alaska and its people, and further finds that this contract is in compliance with all requirements of law;

BE IT RESOLVED by the Alaska State Legislature that the "Gas Purchase Contract" dated April 11, 1977, with the Alaska Pipeline Company and the commissioner of natural resources for the sale and purchase of royalty natural gas from the North Cook Inlet Field is hereby approved.

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AGO 801315

Introduced: 4/22/77
Referred: Resources

IN THE SENATE

BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

SENATE CONCURRENT RESOLUTION NO. 56

IN THE LEGISLATURE OF THE STATE OF ALASKA

TENTH LEGISLATURE - FIRST SESSION

Approving the disposal to Alaska Pipeline Company of royalty gas taken in-kind

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS, under AS 38.06.055(a), each house of the legislature must approve by concurrent resolution all sales of state-owned royalty natural gas before the sale may be consummated; and

WHEREAS the State of Alaska has the right under AS 38.05.180 and its oil and gas leases to receive royalty natural gas either in-kind or in-value from fields in the Cook Inlet area; and

WHEREAS the commissioner of natural resources has entered into a contract for the sale of state-owned royalty natural gas from the North Cook Inlet Field to Alaska Pipeline Company; and

WHEREAS the Alaska Royalty Oil & Gas Development Advisory Board approved the contract for the sale of royalty natural gas from the North Cook Inlet Field to Alaska Pipeline Company; and

WHEREAS the legislature has reviewed this contract and conducted hearings and otherwise received public input on this contract; and

WHEREAS the legislature finds this contract to be in the public interest of Alaska and its people, and further finds that this contract is in compliance with all requirements of law;

BE IT RESOLVED by the Alaska State Legislature that the "Gas Purchase Contract" dated April 11, 1977, with the Alaska Pipeline Company and the commissioner of natural resources for the sale and purchase of royalty natural gas from the North Cook Inlet Field is hereby approved.

AGO 801316

JAY S. HAMMOND
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

April 22, 1977

The Honorable John L. Rader
President of the Senate
Alaska State Legislature
Juneau, Alaska 99811

Dear Mr. President:

Under authority of art. III, sec. 18 of the Alaska Constitution, and in accordance with AS 24.30.060(b) and the Uniform Rules of the Alaska State Legislature, I am transmitting a resolution giving legislative approval to a sale of royalty natural gas from the North Cook Inlet Field to Alaska Pipeline Company. AS 38.06.055(a) provides that no sale of state-owned royalty oil may be made unless approved by concurrent resolution of the legislature.

The Alaska Royalty Oil and Gas Development Advisory Board reviewed the contract and granted its approval on April 6, 1977. The Board's declarations and findings are included in the material submitted to each legislator today. I would be pleased to assist you with any additional information which you request.

Last year the State of Alaska and the Alaska Pipeline Company entered into a contract for the sale of the same royalty gas to Alaska Pipeline Company. That contract was approved by the legislature last session. However, certain difficulties with volume flexibility and arranging for the transportation of the gas from the offshore platform to shore prevented Alaska Pipeline Company from receiving the gas under that contract. The current agreement has been executed to solve these problems and allow royalty gas to be delivered to Alaska Pipeline Company.

The problems with the previous agreement were:

1. Alaska Pipeline Company was unable to use all of the royalty gas at all times (as required in the contract) due to lack of an adequate market; and yet, because of limitations also included in the contract, is unable to sell the excess gas back to Phillips Petroleum Company for export from the State.

2. Alaska Pipeline Company was unable to enter into an agreement with Phillips Petroleum Company for transporting of the gas to shore from the production platform due to understandable reluctance of Phillips to expose themselves to the jurisdiction of the Public Utilities Commission or the Pipeline Commission. The new agreement I am submitting to the legislature today remedies these problems.

This new agreement with Alaska Pipeline necessitated that the State itself also enter into an agreement with Phillips Petroleum Company for delivery of the royalty gas from the platform to shore. This agreement requires that the State pay the cost of gathering and compressing the royalty gas to the point of delivery; however, Alaska Pipeline Company in turn agrees to pay these costs to Phillips for the account of the State. The Royalty Board has neither responsibility nor authority to judge the appropriateness of the level of these charges, and has not done so.

Phillips Petroleum Company has operational problems affecting their ability to deliver guaranteed volumes of royalty gas to shore, as does Alaska Pipeline Company affecting their ability to market the gas available. These companies, together with the State, have agreed to use their "best reasonable efforts" to accommodate the needs of one another to produce and market royalty gas.

The contract between the State and Phillips does not strictly require legislative approval since it does not involve a sale of royalty gas. Nevertheless, I have included it in the materials submitted to the legislature because it is an integral part of the sale of royalty gas to Alaska Pipeline Company.

I believe your careful review of the enclosed materials will reveal many questions regarding this approach to resolving the many problmes associated with the acquiring and delivery of this royalty gas. However, I also believe that these agreements are the best possible solution at this time, are in the best interest of the State, and are important to the long-term interest of Anchorage utility customers.

Thank you for your consideration.

Sincerely,

Jay S. Hammond
Governor

Materials for Legislature

Alaska Pipeline Company

List of materials submitted to each legislator.

1. Gas Purchase Contract dated April 11, 1977 between Alaska Pipeline Company and the State of Alaska.

2. Agreement dated April 11, 1977 between Phillips Petroleum Company and the State of Alaska.

3. Reasons for Sale and Purchase of State Royalty Gas to Alaska Pipeline Company and for Agreement with Phillips Petroleum Company.

4. Findings and Conclusions of the Commissioner Pursuant to Alaska Statute 38.01.113(c) (determination not to use competitive bid procedures.)

5. Approvals relating to above by Alaska Royalty Oil and Gas Development Advisory Board dated April 6, 1977.

6. Attorney General's opinions relating to jurisdiction of Public Utilities Commission and Pipeline Commission.

7. Memos relating to gathering and compression charges.

AGREEMENT

This Contract, made and entered into this 11th day of April, 1977, by and between the State of Alaska, herein referred to as "State", and Phillips Petroleum Company, herein referred to as "Lessee",

W I T N E S S E T H

WHEREAS, Lessee is the holder of certain mineral leases from the State in the North Cook Inlet area of Alaska, said leases identified in Exhibit "A" to this Agreement; and

WHEREAS, the State has the right under the terms of said leases to receive in value or in kind a 1/8 (one-eighth) royalty share of natural gas produced from said leases; and

WHEREAS, the State desires to receive its in kind royalty share of natural gas at a point other than at Lessee's production platform; and

WHEREAS, Lessee operates a gas pipeline to gather natural gas from the said leases to the LNG facility at Kenai, Alaska (hereinafter referred to as Kenai LNG Plant), which Lessee operates; and

WHEREAS, Lessee is willing to deliver to the State its in kind royalty share of the natural gas from said leases at a point near the Kenai LNG Plant; and

WHEREAS, the State desires to receive its royalty share of the natural gas from said leases at such a point

and has agreed with Alaska Pipeline Company to sell such gas to Alaska Pipeline Company (herein referred to as "APC") for resale and use within the State of Alaska according to the terms of that certain Gas Purchase Contract attached hereto as Exhibit "B".

NOW, THEREFORE, premises considered, the State and Lessee hereby mutually agree as follows:

ARTICLE I

DEFINITIONS

The following terms when used in this Agreement shall have the following meanings:

1.1 The term "day" shall mean a period of twenty-four (24) consecutive hours beginning and ending at 7:00 o'clock A.M. The reference date for any day shall be the date of the beginning of such day.

1.2 The term "month" shall mean a period beginning at 7:00 o'clock A.M. on the first day of a calendar month and ending at 7:00 o'clock A.M. on the first day of the next succeeding calendar month.

1.3 The term "Mcf" shall mean one thousand (1,000) cubic feet of natural gas measured as hereinafter provided.

ARTICLE II

The State's Royalty Gas

2.1 Within 30 days after the execution and approval of this Agreement as required by the laws of the State of Alaska, the State shall notify the Lessee under the leases

set forth at Exhibit A, the State's election to take its royalty gas in kind. Said notice will provide that the Lessee shall commence the delivery of said royalty gas to the State (or to the State's designee) upon a receipt of notice from the State that all facilities necessary to receive and market said gas are ready; provided, however, in no event shall Lessee be required to commence the delivery of royalty gas to the State (or its designee) prior to six (6) months following Lessee's receipt of notice of the State's election to take its royalty gas in kind.

2.2 In order that the State give Lessee as much advance notice as possible of the date it will start receiving its royalty gas in kind, the State shall notify Lessee that all facilities necessary to receive and market said gas are ready, at least sixty (60) days prior to the date on which Lessee shall be required to commence delivery pursuant to this Agreement.

ARTICLE III

FACILITIES

3.1 Lessee is presently operating and maintaining a natural gas gathering system between the North Cook Inlet Field and the Kenai LNG Plant.

3.2 The State or its designee shall install, maintain and operate all pipeline, pressure regulators, and related facilities necessary to receive gas hereunder at the point of delivery hereinafter specified. Said point of delivery shall be at or near the existing pipeline tap being presently used to deliver gas from Lessee's pipeline to the

Tesoro refinery located in the general vicinity of the Kenai LNG Plant on the North Kenai Road.

3.3 The State or its designee shall install, operate and maintain all necessary equipment at the point of delivery and at the State's or its designee's measuring station(s) (hereinafter called the "point of measurement") to properly control, odorize, and measure the volumes of gas delivered hereunder.

3.4 Lessee hereby grants the State or its designee ingress and egress at the point of delivery without charge for all purposes necessary hereto, and the State and its designee hereby agree to assure Lessee ingress and egress at the point of measurement and between the point of delivery and the point of measurement without charge for all purposes necessary hereto.

ARTICLE IV

QUANTITY OF GAS

4.1 Subject to the availability of capacity in its facilities to handle volumes in excess of its own needs and to the extent of such availability, and upon proper written notice from the State under Article II hereof, Lessee shall gather the royalty gas in the North Cook Inlet Field and deliver same to the State at the point of delivery specified herein. The State is entitled to receive at the wellhead 1/8 (one-eighth) of the natural gas produced from the leases listed in Exhibit "A", and to the extent that Lessee gathers and delivers more or less than the amount of royalty gas to which the State is entitled,

that difference shall be carried in the over and short account described below or Lessee shall purchase same on the basis provided in Section 4.3 below.

It is recognized that it is impossible to deliver to the State or for the State or its designee to receive the exact amount of royalty gas produced from the leases listed in Exhibit "A". Lessee agrees that it will carry an over and short account with respect to the receipts of royalty gas and the delivery of same to the State, provided, however, that Lessee shall never be required to carry more than a total of 60,000 Mcf over or under delivery. In the event the takes by the State on a cumulative basis shall ever be more than 60,000 Mcf less than the amount of royalty gas available at the point of delivery, the State shall not be allowed to make up for any such underdelivery, and Lessee shall purchase the excess undelivered quantities of royalty gas over 60,000 Mcf from the State at the wellhead on the basis provided in section 4.3 below.

4.2 Subject to (i) the availability of royalty gas at the platform and (ii) to the State's or its designee's requirements, and (iii) the State's or its designee's ability to take such requirement, Lessee shall use its best reasonable efforts to deliver to the State or its designee at the delivery point specified herein on an annual basis not less than three (3) billion cubic feet of royalty gas; provided, however, that in using such best reasonable efforts, Lessee shall not be required to install or operate any pipeline, compression or other facilities which, when operating as a reasonably prudent operator, it would not otherwise install

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and/or operate.

4.3 The parties recognize that the State contemplates selling such royalty gas to Alaska Pipeline Company and that such purchaser may be unable from time to time to take and deliver to its customers the full volumes of gas attributable to the State's royalty interest although it is committed to purchase that volume from the State. In such event, Lessee agrees to purchase from the State from time to time those volumes which APC is unable to take. For such volumes which it purchases from the State, Lessee will pay the State a price equal to that amount which Lessee would have otherwise paid to the State as royalty if the State had not elected to receive its royalty gas in kind, and Lessee will not charge the State for gathering or compressing such volumes of gas or for other charges under this Agreement.

ARTICLE V

POINT OF DELIVERY AND OWNERSHIP

5.1 The point of delivery to the State for all gas gathered and delivered hereunder by Lessee shall be at the juncture of APC's facilities and Lessee's facilities located near the pipeline tap serving the Tesoro refinery as mentioned in Section 3.2 of this Agreement.

5.2 Lessee shall be deemed to be in control and possession of the gas deliverable hereunder and responsible for any damage or injury caused thereby until said gas shall have been delivered to the State or its designee at the point of delivery, after which delivery State or its designee shall be deemed to be in exclusive control and possession of

the gas and responsible for any injury or damage caused thereby.

5.3 Measurement of royalty gas shall be the responsibility of the State or its designee subject to Lessee's right to verify such measurement or to install and operate check metering equipment, and shall be done at a metering station(s) on the North Kenai Road, called the "point of measurement". The State or its designee shall be responsible for any gas lost between the point of delivery and the point of measurement.

ARTICLE VI

QUALITY, PRESSURE, AND ODORIZATION

6.1 Lessee shall deliver gas hereunder at the pressure existing from time to time in its facilities at the point of delivery.

6.2 Lessee agrees that the quality of gas, when delivered at the point of delivery hereunder, shall be the quality of gas existing in its gathering system from time to time and the State agrees to accept such gas.

6.3 It is understood that the gas delivered hereunder will not be odorized by Lessee, and if the State or its purchaser so utilizes the gas delivered hereunder for purposes which require odorization of such gas, the full responsibility for such use is the State's. Lessee shall have no responsibility for odorizing such gas irrespective of the State's disposition of same.

ARTICLE VII

STANDARDS OF MEASUREMENT AND TESTS

7.1 Except for the determination and computation

of total heating value, the unit of volume of gas delivered hereunder shall be one (1) cubic foot at an absolute pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch and at a base temperature of sixty (60) degrees Fahrenheit.

7.2 The volumes of gas delivered hereunder shall be measured and computed by the State or its designee in accordance with the methods prescribed in Gas Measurement Committee Report No. 3, Natural Gas Department, American Gas Association, including the Appendix thereto, dated April, 1965, except that the atmospheric pressure shall be assumed to fourteen and seven-tenths (14.7) pounds per square inch. The method used for correcting such volumes for deviation from the Ideal Gas Laws shall be the procedure recommended in the most current Report of the American Gas Association or by any other method mutually agreeable to the parties hereto.

7.3 The specific gravity of the gas delivered hereunder shall be determined by Lessee's utilizing the method prescribed in American Petroleum Institute Code No. 50-A at the beginning of delivery hereunder and once during each month thereafter. The results of each such determination shall be used in computing the volume of gas delivered hereunder until the effective date of the next succeeding test.

7.4 The flowing temperature of the gas delivered hereunder shall be determined by means of a continuous recording thermometer installed by the State or its designee so that it will properly record the temperature of the gas flowing through the meter. The arithmetical average of the

hourly temperatures recorded each day shall be used in computing the volumes of gas delivered during such day.

7.5 If the gas delivered hereunder is solely from the 16-inch pipeline serving the North Cook Inlet Field, the total heating value of the gas shall be the average of that recorded on the recording calorimeter for Lessee's gas at the inlet to Kenai LNG Plant during the billing period corrected to thirty (30) inches of Mercury and sixty (60) degrees Fahrenheit dry.

ARTICLE VIII

MEASUREMENT

8.1 As agreed in Section 5.3 hereof, the State or its designee shall be obligated to and be responsible for all metering of gas hereunder.

8.2 The State or Lessee may, at their option and expense, install check meters upstream or downstream of the State's or its designee's meter station provided that such check meters will be installed so as not to interfere with the operation of the State's or its designee's facilities. The calibrating and adjusting of meters and the changing of charts and the reading of charts on meters shall be done by the party who installed the meters.

8.3 The State and Lessee shall have access at all times to the State's or its designee's metering equipment including all other instruments used by the State or its designee in determining the measurement and quality of the gas delivered hereunder, but the reading, calibrating and adjusting thereof, and the changing of charts shall be done

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only by the employees, agents, or representatives of the State or its designee. Upon request of Lessee, the State or its designee shall submit to Lessee records and charts from such equipment subject to return by Lessee within thirty (30) days after receipt thereof.

8.4 At least once a month the State or its designee shall test its above-mentioned metering equipment or cause the same to be tested and shall give Lessee or its representative reasonable prior notice of the time all such tests are to be made so that Lessee may, if desired, have its representative present to observe such tests and any adjustments made upon such metering equipment. Following any test, any of the State's or its designee's metering equipment found to be inaccurate to any degree shall be adjusted immediately to measure accurately. If upon any test such metering equipment is found to be inaccurate by two percent (2%) or more, registration from said metering equipment and any payments based upon such registrations shall be corrected at the rate of such inaccuracy for any period of inaccuracy which is definitely known or agreed upon, but in case the period is not definitely known or agreed upon, then for a period extending back one-half (1/2) of the time elapsed since the last previous test, not exceeding, however, fifteen (15) days.

8.5 If for any reason the State's or its designee's meter is out of service or is found registering inaccurately and the error is not determinable by ordinary test such that the volume of gas delivered through such meter cannot be ascertained or computed from the readings thereof, the

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volume of gas so delivered during the period the meter is out of service or registering inaccurately shall be estimated and agreed upon by the parties hereto upon the basis of the best available data, using the first of the following methods which is feasible:

(a) by correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation;

(b) By using the registration of any check measuring equipment of Lessee if installed and registering accurately;

(c) By estimating the volume by comparing it with deliveries during preceding periods under similar conditions when the meter was registering accurately.

ARTICLE IX

GATHERING AND COMPRESSION CHARGES AND TAXES

9.1 For all gas delivered by Lessee to the State at the delivery point, the State or its designee shall pay to Lessee a gathering charge of ten cents (10.0¢) per Mcf from the date of first delivery hereunder. The above-stated charge shall increase by six percent (6%) compounded annually, on each anniversary date of the date this Agreement.

9.2 It is recognized by the parties hereto that it may be necessary for Lessee to install compression facilities during the term of this Agreement. At the time the first compressor unit is installed and first used, the State

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or its designee shall pay Lessee in addition to the gathering charge set forth in Section 9.1, a compression charge of ten cents (10.0¢) per Mcf for all gas delivered by Lessee to the State at the delivery point. Such charge shall increase by six percent (6%) per year, compounded annually, commencing on the first anniversary of the date such compression facilities are installed and first used.

9.3 In the event that Lessee installs or causes to be installed from time to time compression facilities in addition to the first compressor unit mentioned in Section 2, above, Lessee shall give the State and its designee written notice at least six (6) months prior to the time Lessee anticipates placing any additional unit or units in operation in order to maintain capacity in its gathering system. Such notice shall also terminate this Agreement at the end of such six (6) months period. If, within ninety (90) days of the date of such notice the parties shall agree upon a new compression charge to be applicable when such additional compression facilities go into operation, then this Agreement shall not terminate but shall continue in full force and effect as amended to include the new compression charge.

9.4 Lessee shall pay all ad valorem taxes on its pipelines and facilities employed in delivering gas hereunder. In addition to the price and payments hereinabove provided, the State shall reimburse Lessee in the proportion of deliveries made to the State by Lessee, an amount equal to the aggregate total of any new or increased fee, impost, duty, charge, excise or tax levied or imposed in addition to the rates at which those, if any, are levied, assessed, or

fixed as of the date hereof, with respect to the gathering of the royalty gas delivered hereunder (including compression) prior to its delivery to the State that Lessee may be required to pay for directly or indirectly.

ARTICLE X

BILLING AND PAYMENTS

10.1 On or before the 15th day of each month during the term hereof the State or its designee shall furnish Lessee with a full and complete statement reflecting all gas delivered by Lessee during the preceding month and the total amount due hereunder pursuant to Article IX hereof. Payment hereunder shall be made to Lessee at its office in Bartlesville, Oklahoma within ten (10) days after delivery of each such statement.

10.2 On or before the 30th day of each month during the term hereof Lessee shall furnish to the State or its designee a full and complete statement reflecting the total amount of royalty gas produced by Lessee during the preceding month. Deducting the quantity taken by the State for such month, Lessee shall determine the amount of royalty gas not taken by the State for such month and shall make payment therefor to the State together with said statement.

10.3 Each party hereto shall have, at its expense, the right to examine the books and records of the other party to the extent necessary to verify the accuracy of any statement or invoice made under or pursuant to this contract. Any statement shall be final as to both parties unless questioned in writing within two (2) years after payment

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thereof has been made.

ARTICLE XI

REPRESENTATION AND CONDITION PRECEDENT

11.1 It is expressly recognized and agreed that the gas gathering system utilized for deliveries hereunder is operated and maintained by Lessee for its own purpose and Lessee does not, by entering into this Agreement, dedicate any facilities or otherwise undertake to render any service to or for the public. This Agreement is being undertaken solely to effectuate the delivery of royalty gas to the State, and the State makes the material representation that neither this Agreement nor the State's use or disposition of the gas delivered hereunder will subject Lessee to regulation by the Federal Power Commission, the Alaska Public Utilities Commission, or the Alaska Pipeline Commission.

11.2 In the event that any governmental agency shall declare that Lessee's activities hereunder subject Lessee to regulation as a utility, then either party shall have the option to terminate this Agreement upon thirty (30) days' notice in writing.

ARTICLE XII

ALASKA PIPELINE COMPANY

12.1 The State has entered into a Gas Purchase Agreement with Alaska Pipeline Company, under the terms of which APC will purchase the State's royalty gas after same has been delivered by Lessee to the State. Under such contract, APC has agreed to make for the State's account all

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payments required by Articles IX and X hereof. Lessee agrees to accept such payments by APC as satisfaction of the State's obligations under Articles IX and X hereof. In the event of default by APC in making such payments, Lessee shall promptly notify the State and if such default continues for a period of thirty (30) days after such notice, Lessee shall have the option of terminating this Agreement in its entirety.

12.2 Lessee agrees to accept the State's designation of APC as the State's designee hereunder for the performance of any other obligations which the provisions hereof place on the State.

12.3 By its execution hereof APC ratifies all of the terms, covenants, conditions, and representations hereof.

ARTICLE XIII

FORCE MAJEURE

13.1 No liability shall result to either party from delay in performance or non-performance of any obligation hereunder (except the State's obligation to make payment hereunder) caused by circumstances reasonably beyond the control of the party affected, including, but not limited to, acts of God, fire, flood, storm, war (declared or undeclared), repair of facilities, breakage or accident to machinery or lines of pipe, repair, redrilling or reworking of wells, governmental regulation, requisition or direction, or labor strikes or lockouts.

13.2 The party claiming relief under this Article XIII shall advise the other party with reasonable promptness

in writing giving full particulars of the cause or causes relied upon and shall also give prompt notice in writing of the cessation of any such cause or causes. The party claiming force majeure shall exercise due diligence in undertaking to remedy and overcome the cause of delay hereunder, but neither party shall be required to agree to any demand of labor to settle any strike or labor dispute except in the sole discretion of the party subject to such strike or labor dispute.

ARTICLE XIV

TERM

14.1 This Agreement shall become effective upon the execution hereof and the execution and approval of the Alaska Royalty Oil and Gas Development Advisory Board and the State Legislature of the Contract attached as Exhibit "B" hereto and shall remain in effect until June 1, 1984, unless terminated or extended prior to such date by mutual agreement of the parties, or pursuant to this Article or Article XI or XIII.

14.2 In the event that the Agreement attached hereto as Exhibit "B" is terminated, this Agreement may be terminated by either party upon thirty (30) days notice.

14.3 If deliveries to the State or its designee hereunder have not commenced on or before June 30, 1978, then this Agreement shall terminate immediately.

14.4 In the event of termination of this Agreement or of deliveries of royalty gas hereunder, the parties agree that such termination shall have the effect of revoking the State's election to receive its royalty gas in-kind

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as of the date of termination and Lessee shall immediately commence such royalty payment under the terms of the leases listed in Exhibit "A" to assure the state of its full royalty share on all gas produced from the leases.

ARTICLE XV

MISCELLANEOUS

15.1 Except as herein otherwise provided, any notice, request, demand, statement or bill provided for in this Agreement, or any notice which either party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered mail to either of the parties hereto as the case may be at the following address:

Commissioner of Natural Resources
State of Alaska
Pouch M
Juneau, Alaska 99811

Phillips Petroleum Company
Attn: Gas and Gas Liquids Division
Bartlesville, Oklahoma 74004

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

or at such other address as either party shall designate from time to time by formal written notice. Routine communications, including monthly statements and payments, shall be considered as duly delivered when mailed by either registered or ordinary mail.

IN WITNESS WHEREOF, this Agreement is executed as of the day and year first above written.

STATE OF ALASKA

By _____

ATTEST:

_____
Assistant Secretary

PHILLIPS PETROLEUM COMPANY

By _____
Vice President
ATTORNEY IN FACT

ATTEST:

_____
Assistant Secretary

ALASKA PIPELINE COMPANY

By _____
President

GAS PURCHASE CONTRACT

This Contract, made and entered into this 11th day of April 1977, by and between the Alaska Pipeline Company ("APC") herein referred to as "Buyer" and the State of Alaska, hereinafter referred to as "Seller":

WITNESSETH

WHEREAS, Buyer owns and operates a natural gas pipeline system in areas of Alaska for the delivery of natural gas for ultimate consumption within the State of Alaska, and

WHEREAS, Seller has the right under each of the leases, identified in Exhibit "A" to this Contract, to be paid by Lessee thereunder a royalty of twelve and one-half percent in-kind or in-value of the natural gas produced and saved or used off of the lands covered by each lease, and

WHEREAS, Seller is authorized by AS 38.05.183 to sell royalty gas; and

WHEREAS, Buyer represents to Seller that the gas received by Buyer under this contract will be used to meet the requirements of its customers within the State of Alaska; and

WHEREAS, this Gas Purchase Contract when executed will supersede and extinguish that certain Gas Purchase Contract executed June 4, 1976 by the parties hereto;

NOW, THEREFORE, in consideration of the representations, covenants, and conditions herein contained, Buyer and Seller hereby agree as follows:

The "Gas Purchase Contract" dated April 11, 1977, between Alaska Pipeline Company and the State of Alaska is hereby amended by adding this page 1(a) between pages 1 and 2.

ARTICLE I

DEFINITIONS

The following terms when used in this contract shall have the following meanings:

1.1 The term "day" shall mean a period of twenty-four (24) consecutive hours beginning and ending at 7:00 o'clock A.M. The reference date for any day shall be the date of the beginning of such day.

1.2 The term "month" shall mean a period beginning at 7:00 o'clock A.M. on the first day of a calendar month and ending at 7:00 o'clock A.M. on the first day of the next succeeding calendar month.

1.3 The term "Mcf" shall mean one thousand (1,000) cubic feet of natural gas measured as hereinafter provided.

Alaska Pipeline Company

Date: 4-20-77

State of Alaska

Date: 4-19-77

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ARTICLE II RC 4-19-77 Dec Sec 4-20-77

~~DEFINITIONS~~

Seller's Royalty Gas

2.1 Seller hereby agrees that within 30 days after the execution and approval of this agreement as required by the laws of the State of Alaska, Seller shall notify the Lessee under the leases set forth at Exhibit "A" of Seller's election to take its royalty gas in-kind. Said notice will provide that the Lessee shall commence the delivery of said royalty gas to Seller or to Seller's designee upon a receipt of notice from Seller that all facilities necessary to enable Buyer to receive and market said gas are ready; provided, however, in no event shall Lessee be required to commence the delivery of royalty gas to Seller or its designee prior to six (6) months following Lessee's receipt of notice of Seller's election to take its royalty gas in-kind.

2.2 In order that Seller can give its Lessee as much advance notice as possible of the date it will start receiving its royalty gas in-kind, Buyer shall notify Seller, and Seller shall notify its Lessee, that all facilities necessary to receive and market said gas are ready, at least 60 days prior to the date Buyer will receive gas from Seller pursuant to this Contract.

2.3 Buyer agrees that Seller's royalty gas which is purchased and received by Buyer will be used or resold for use

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within the State of Alaska.

ARTICLE III

Quantity

3.1 It is understood and agreed by the parties that the volume of gas available to Seller from the leases covered by this Contract depends upon the production from the leases over which Seller has no control, and further depends upon the Lessee's gathering capacity installed and available, over which Seller likewise has no control. Buyer hereby agrees to purchase on each day commencing with the date of first delivery hereunder and continuing during the term of this contract up to all of Seller's royalty gas available at the point of delivery described in Section 5.1 hereof, it being understood that Buyer's requirements for its markets may not allow Buyer to purchase the entire amount of Seller's royalty gas on each day it is available; and it being further understood that Buyer will take not less than the amount for which Buyer has demand and delivery facilities available. Buyer shall use its best reasonable efforts to take not less than three (3) billion cubic feet per year of royalty gas at the point of delivery.

3.2 It is recognized that it is impossible to deliver to Buyer each day the exact amount of royalty gas produced from the leases listed in Exhibit "A". Seller agrees that Seller or Lessee will carry an over and short account with respect to the receipts of royalty gas and the delivery of same to Buyer; provided,

however, that the account shall never be required to carry more more than a total of 60,000 Mcf over or underdelivery. In the event the takes by Buyer on a cumulative basis shall ever be more than 60,000 Mcf less than the amount of royalty gas available to Buyer at the point of delivery, Buyer shall not be allowed to make up for any such underdelivery and Seller may sell the undelivered quantity of royalty gas to Lessee.

ARTICLE IV

Quality, Pressure, and Odorization

4.1 The gas to be delivered by Seller to Buyer at the delivery point shall be gas of the same quality and pressure as delivered to Seller by the Lessee at the point of delivery. Seller shall have no obligation to improve the quality or pressure of gas beyond that quality and pressure at which Lessee delivers the gas to seller.

4.2 Gas delivered hereunder will not be odorized and if Buyer so utilizes the gas delivered hereunder for purposes which require odorization of such gas, the full responsibility for such use is Buyer's and Buyer agrees to comply with all laws and regulations respecting the odorization of such gas and hereby indemnifies and holds Seller harmless from any and all claims, injuries, expenses, penalties and damages arising out of or connected with Buyer's failure to observe strictly and comply with all laws, rules and regulations with respect hereto.

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ARTICLE V

Point of Delivery, Point of Measurement, Ownership, and Measurement

5.1 Buyer shall install, maintain, and operate a connection into the Lessee's pipeline system at or near Lessee's pipeline tap which delivers gas from Lessee's pipeline to the Tesoro refinery located in the general vicinity of the Kenai LNG plant on the North Kenai Road, (hereinafter called "the point of delivery"). The point of delivery of all gas delivered hereunder shall be at the same point of delivery that Seller receives its royalty gas from the Lessee.

5.2 Buyer agrees to install, maintain, and operate all pipeline, pressure regulators, and related facilities necessary to receive gas hereunder at and from the point of delivery above specified, to Buyer's metering station(s) also located in the general vicinity of the Kenai LNG plant on the North Kenai Road (hereinafter called "the point of measurement").

5.3 Buyer shall be deemed to be in control and possession of the gas delivered hereunder at and from the point of delivery and responsible for any damage or injury caused thereby. Buyer shall be responsible for any gas lost between the point of delivery and the point of measurement. Buyer shall indemnify and hold Seller harmless as to any injury or damage arising out of the delivery of gas to Buyer and its measurement hereunder.

5.4 Standards of Measurements and Tests

5.4.1 Except for the determination and computation of total heating value, the unit of volume of gas delivered hereunder shall be one (1) cubic foot at an absolute pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch and at a base temperature of sixty (60) degrees Fahrenheit.

5.4.2 The volumes of gas delivered hereunder shall be measured and computed by Buyer in accordance with the methods prescribed in Gas Measurement Committee Report No. 3, Natural Gas Department, American Gas Association, including the Appendix thereto, dated April, 1955, except that the atmospheric pressure shall be assumed to be fourteen and seven-tenths (14.7) pounds per square inch. The method used for correcting such volumes for deviation from the Ideal Gas Laws shall be the procedure recommended in the most current Report of the American Gas Association or by any other method mutually agreeable to the parties hereto.

5.4.3 The specific gravity of the gas delivered hereunder shall be determined by Lessee utilizing the method prescribed in American Petroleum Institute Code No. 50-A at the beginning of delivery hereunder and once during each month thereafter. The results of each such determination shall be used in computing the volume of gas delivered hereunder until the effective date of the next succeeding test.

5.4.4 The flowing temperature of the gas delivered hereunder shall be determined by means of a continuous recording thermometer installed by Buyer so that it will properly record

the temperature of the gas flowing through the meter. The arithmetical average of the hourly temperatures recorded each day shall be used in computing the volumes of gas delivered during such day.

5.4.5. If the gas delivered hereunder is solely from the 16-inch pipeline serving the North Cook Inlet Field, the total heating value of the gas shall be the average of that recorded on the recording calorimeter for Lessee's gas at the inlet to Kenai LNG Plant during the billing period corrected to thirty (30) inches of Mercury and sixty (60) degrees Fahrenheit dry.

5.5 Measurement

5.5.1 Seller or Lessee may at their option and expense, install check meters upstream or downstream of Buyer's meter station provided that such check meters will be installed so as not to interfere with the operation of Buyer's facilities. The calibrating and adjusting of meters and the changing of charts and the reading of charts on meters shall be done by the party who installed the meters.

5.5.2 Buyer, Lessee, and Seller shall have access at all times to Buyer's metering equipment including all other instruments used by Buyer in determining the measurement and quality of the gas delivered hereunder, but the reading, calibrating and adjusting thereof, and the changing of charts shall be done only by the employees, agents, or representatives of Buyer. Upon

request of Lessee or Seller, Buyer shall submit to Lessee or Seller records and charts from such equipment subject to return by Lessee or Seller within thirty (30) days after receipt thereof. Buyer hereby agrees to assure Seller and Lessee ingress and egress at the point of measurement and between the point of delivery and the point of measurement without charge for all purposes necessary hereto.

5.5.3 At least once a month Buyer shall test its above mentioned metering equipment or cause the same to be tested and shall give Lessee or its representative reasonable prior notice of the time all such tests are to be made so that Lessee may, if desired, have its representative present to observe such tests and any adjustments made upon such metering equipment. Following any test, any of Buyer's metering equipment found to be inaccurate to any degree shall be adjusted immediately to measure accurately. If upon any test such metering equipment is found to be inaccurate by two percent (2%) or more, registration from said metering equipment and any payments based upon such registrations shall be corrected at the rate of such inaccuracy for any period of inaccuracy which is definitely known or agreed upon, but in case the period is not definitely known or agreed upon, then for a period extending back one-half of the time elapsed since the last previous test, not exceeding however, fifteen (15) days.

Rec 4-20-77
RL 4-19-77

5.5.4 If for any reason Buyer's meter is out of service or is found registering inaccurately and the error is not determinable by ordinary test such that the volume of gas delivered

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through such meter cannot be ascertained or computed from the readings thereof, the volume of gas so delivered during the period the meter is out of service or registering inaccurately shall be estimated and agreed upon by the parties hereto upon the basis of the best available data, using the first of the following methods which is feasible:

(a) By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation;

(b) By using the registration of any check measuring equipment of Lessee if installed and registering accurately;

(c) By estimating the volume by comparing it with deliveries during preceding periods under similar conditions when the meter was registering accurately.

ARTICLE VI

Price and Billing

6.1 The price to be paid by Buyer to Seller for gas deliveries shall be as follows:

(a) Commencing on the date of first deliveries hereunder assuming that this date occurs prior to July 1, 1978 and continuing until the first day of July, 1978, the price shall be 64.65 cents per MCF.

(b) Commencing on the first day of July, 1978 and continuing until the first day of July, 1979 the price shall be the higher of (i) 66.65 cents per

MCF, (ii) the price Seller would have received from Lessee had it not elected to receive its royalty gas in kind, (iii) the highest price paid by any purchaser in the upper Cook Inlet area for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges.

(c) For each succeeding 12 month period commencing July 1, 1979 the price shall be increased to the higher of (i) the previous year's price plus 2 cents per Mcf, (ii) the price Seller would have received had it not elected to take its royalty in-kind, (iii) the highest price paid by any purchaser in the upper Cook Inlet area for gas of similar quality and conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of contract and connection charges.

(d) In addition to the price otherwise payable hereinabove, for gas delivered to Buyer at the delivery point Buyer shall pay to Lessee, for the account of Seller, a gathering charge of ten cents (10.0¢) per Mcf from the date of first delivery hereunder. The above stated charge shall increase six percent (6%) compounded annually on each anniversary of the date of this contract.

(e) It is recognized by the parties hereto that it will be necessary for Lessee to install compression facilities

during the term of this Agreement. At the time the first compressor unit is installed and first used, Buyer shall pay to Lessee, for the account of Seller, in addition to the price and gathering charge otherwise payable hereinabove, a compression charge of ten cents (10.0¢) per Mcf for all gas delivered to Buyer at the delivery point. Such charge shall increase by six percent (6%) per year compounded annually, commencing on the first anniversary of the date such compression facilities are installed and ready for operation. Nothing herein shall be construed by either party as an obligation on Lessee to install any compression facilities whatever or to operate any compression facilities already installed.

(f) In addition to the price provisions stated herein, Buyer hereby agrees to pay Seller as part of the total purchase price of the royalty gas any costs not otherwise stated herein incurred by Seller in transporting that gas to the point of delivery specified in section 5.1 of this agreement including but not limited to any amount which Seller is obligated to reimburse Lessee for a proportion of new or increased fees, imposts, duties, charges, excise or taxes. RL 4-19-77 RC 4-19-77 RC 4-20-77

6.2 Thirty days prior to the date of each annual price change, Seller, at its option, may determine the price which it would have received from its Lessee had it not elected to take its royalty

gas in-kind and the highest price being paid for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges in the upper Cook Inlet area and submit the same to Buyer along with suitable supporting evidence as to such prices. Buyer shall have the right to submit other evidence within the 30 day period.

6.3 On or before the 15th day of each month after the delivery of gas hereunder has commenced Buyer shall furnish Seller and Lessee with a full and complete statement reflecting the quantity of gas delivered at the delivery point during the preceding month and the total amounts due hereunder. Payment under sections 6.1(d), 6.1(e) and 6.1(f) of this Contract shall be made to Lessee on account of Seller at Lessee's office in Bartlesville, Oklahoma within ten (10) days after delivery of each such statement. Payment under sections 6.1(a), 6.1(b) and 6.1(c) of this Contract shall be made to Seller on the day of delivery of each such statement by direct wire transfer of federal reserve funds through the Federal Reserve Bank wire transfer system to the following address:

BANK OF AMERICA, NA + SA
San Francisco, California
Securities Department 3255
~~Attention: Mr. Jeff Beaver~~
Credit to: State of Alaska Investment Account

or to such other address as the Commissioner of Revenue may designate

6.4 Each party hereto shall have, at its expense, the right to examine the books and records of the other party to the extent

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necessary to verify the accuracy of any statement, charge, computation, or demand made under or pursuant to this contract. Any statement shall be final as to both parties unless questioned in writing within two (2) years after payment thereof has been made.

6.5 The terms "upper Cook Inlet area" as used herein shall mean the area encompassed in a radius of 100 kilometers from the Lessee's North Cook Inlet platform.

ARTICLE VII

Termination

7.1 This contract shall become effective upon the execution hereof and the approval of the Alaska Royalty Oil and Gas Development Advisory Board and the State Legislature and shall continue and remain in effect until June 1, 1984 unless terminated or extended prior to such date by mutual agreement of the parties, or pursuant to this Article or Article VIII.

7.2 Seller's obligations hereunder are contingent upon Seller arranging with Lessee for satisfactory transportation of royalty gas sold hereunder to the point of delivery specified in section 5.1 of this agreement. If, after exercising Seller's best efforts, Seller is unable to arrange such transportation on terms satisfactory to Seller, Seller shall give notice to Buyer and this agreement shall terminate 30 days after said notice.

7.3 The parties hereby agree that in the event that any govenmental agency declares that Lessee's activities hereunder subject Lessee to regulation as a utility, then either party shall have the option to give notice to the other and this agreement shall terminate 30 days after said notice.

7.4 In the event of default by Buyer in making the payments required by this Contract, Seller shall give notice to Buyer and if the default continues for a period of 30 days after such notice, Seller shall have the option of terminating this Contract.

7.5 In the event that Lessee installs or causes to be installed compression facilities in addition to the first compressor unit mentioned in section 6.1(e) of this contract, Seller shall give Buyer written notice at least six (6) months prior to the time Lessee anticipates placing such additional facilities in operation to maintain capacity in its gathering system. Such notice shall also terminate this agreement at the end of the six (6) month period unless within ninety (90) days of the date of such notice a new compression charge is agreed upon by the two parties to be applicable when the additional facilities go into operation. If a new compression charge is agreed upon, this agreement shall not terminate but shall continue in full force and effect as amended to include the new compression charge.

7.6 If the agreement between Seller and Lessee attached hereto as Exhibit "B" is terminated for any reason, this agreement may be terminated by either party upon thirty (30) days notice.

7.7 If deliveries to Buyer hereunder have not commenced on or before June 30, 1978, then this Contract shall immediately terminate.

ARTICLE VIII

Representation, Condition Precedent and Force Majeure

8.1 It is expressly recognized and agreed that the gas gathering system utilized for deliveries hereunder is operated and maintained by Lessee for its own purpose and that Lessee will not dedicate any facilities or otherwise undertake to render any service to or for the public. This Agreement is being undertaken solely to effectuate the delivery of royalty gas which Buyer is purchasing from the State of Alaska, and the parties hereto make the material representation that neither this Agreement nor Buyer's use or disposition of the gas delivered hereunder will subject Lessee to regulation by the Federal Power Commission or the Alaska Public Utilities Commission or the Alaska Pipeline Commission.

8.2 Force Majeure

8.2.1 No liability shall result to either party from delay in performance or non-performance of any obligation hereunder (except Buyer's obligation to make payment hereunder) caused by circumstances reasonably beyond the control of the party affected, including, but not limited to, acts of God, fire, flood, storm, war (declared or undeclared), repair of facilities, breakage or accident to machinery or lines of pipe, repair, redrilling or reworking of wells, governmental regulation, requisition or direction, labor strikes or lockouts or breach of contract by Lessee.

8.2.2 The party claiming relief under this Article VIII shall advise the other party with reasonable promptness in writing

giving full particulars of the cause or causes relied upon and shall also give prompt notice in writing of the cessation of any such cause or causes. The party claiming force majeure shall exercise due diligence in undertaking to remedy and overcome the cause of delay hereunder, but neither party shall be required to agree to any demand of labor to settle any strike or labor dispute except in the sole discretion of the party subject to such strike or labor dispute.

ARTICLE IX

Miscellaneous

9.1 The terms and provisions of this Agreement shall extend to and be binding upon the parties hereto, their assigns and successors in interest. It is understood, however, that Buyer may not assign its rights and interest in this Agreement without the written consent of Seller, except as may be necessary to Buyer to conform with its various financing documents or as may be desirable to Buyer as to its commonly owned affiliate or subsidiary. No assignment shall relieve any assignor of this Agreement of its obligations hereunder without the written consent of Seller.

9.2 In the event Buyer does not receive or purchase all of said royalty gas which is available to Buyer, then Seller may receive and dispose of that portion not taken by Buyer provided Seller does not burden Buyer with any cost therefor, including Lessee's charges for gathering and compression on the gas not taken by Buyer.

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ARTICLE X

Notices

10.1 Except as herein otherwise provided, any notice, request, demand, statement or bill provided for in this Contract, or any notice which either party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered mail to either of the parties hereto as the case may be at the following address:

Commissioner of Natural Resources
State of Alaska
Pouch M
Juneau, Alaska 99811

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

or at such other address as either party shall designate from time to time by formal written notice. Routine communications, including monthly statements and payments, shall be considered as duly delivered when mailed by either registered or ordinary mail except payments for royalty gas from Buyer to Seller which must be made by wire transfer under section 6.3 of this Contract.

IN WITNESS WHEREOF, the parties hereto have caused this Contract to be executed in two (2) original counterparts on this day and year first above written.

BUYER

STATE OF ALASKA

ATTEST:

ATTEST:

EXHIBIT "A"

Attached to and Made a Part of a Gas Purchase and Sales Agreement dated April 11, 1977, Between ALASKA PIPELINE COMPANY "Buyer" and the STATE OF ALASKA "Seller", With Respect to Certain Royalty Gas Owned and Taken in Kind by SELLER Under the Leases Described Herein Covering Lands in the State of Alaska.

Each of the Following described Leases reserves to the State of Alaska a one-eighth royalty interest.

Lease Serial No.	Legal Description	Gross Acres
ADL-17589 2/1/62	T.12N., R.9W., S.M. Sec. 31: All; Sec. 32: All. T.11N., R.9W., S.M. Sec. 5: All; Sec. 6: All; Sec. 7: All; Sec. 18: N 1/2. T.11N., R.10W., S.M. Sec. 12: All; Sec. 13: N 1/2.	4,375.50
ADL-17590 3/1/62	T.12N., R.9W., S.M. Sec. 21: W 1/2; Sec. 28: W 1/2.	640.00
ADL-18740 9/1/62	T.12N., R.10W., S.M. Sec. 35: SE 1/4. T.11N., R.10W., S.M. Sec. 2: E 1/2; Sec. 11: E 1/2.	800.00
ADL-18741 9/1/62	T11N., R.9W., S.M. Sec. 9: N 1/2, SW 1/4. T.12N., R.9W., S.M. Sec. 33: NW 1/4.	640.00

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ADL-37831
9/1/62

T.12N., R.9W., S.M.	3,326.00
Sec. 29: All;	
Sec. 30: All;	
Sec. 19: SE 1/4;	
Sec. 20: NE 1/4, S 1/2.	
T.12N., R.10W., S.M.	
Sec. 36: All;	
Sec. 25: SE 1/4.	
T.11N., R.10W., S.M.	
Sec. 1: All.	

Exhibit "A"

Summary and Background for Sale and
Purchase of State Royalty Gas to Alaska
Pipeline Company and for related
Agreement with Phillips Petroleum Company

This contract entitled "Gas Purchase Contract", dated April 11, 1977, between Alaska Pipeline Company (Buyer) and the State of Alaska (Seller) is regarding the sale and purchase of State royalty gas. To accomodate delivery of gas under the above contract it was necessary to enter into an agreement dated April 11, 1977 between Phillips Petroleum Company (Lessee) and the State of Alaska. The above contracts will supercede the contract entitled "Gas Purchase Contract", dated June 4, 1976 between Alaska Pipeline Company and the State of Alaska and was approved by the legislature. The new agreements are necessary because certain of the provisions of the old agreement have proven unworkable.

The following exhibits are submitted in support of these agreements:

1. Gas Purchase Contract dated June 4, 1976 between APC and the State.
2. North Cook Inlet Field Royalty Gas, Commissioner's Proposal in Concept.
3. House Concurrent Resolution No. 142, introduced May 4, 1976.
4. Letter dated April 30, 1976 to the Speaker of the House from the Governor.
5. Findings and Conclusions for Non-Competive Sale.

The reasons that the Contract entered into last year could not become operational are as follows:

1. Article 2.1 of that agreement required that Buyer was to purchase all royalty gas available at the point of delivery (wellhead). Buyer does not have adequate demand to take all of the gas all of the time. Buyer agreed that all gas purchased under the contract will be used to meet the requirements of its customers within the State of Alaska. One solution to Buyer's inability to use all of the royalty gas might have been for Buyer to sell its surplus gas back to Phillips Petroleum. Had Buyer done that it may have been in breach of last years contract because Buyer agreed to use the gas for its customers and the sale was for in-state use. Phillips, however, sells the gas out-of-state.

2. The point of delivery of the gas was at the wellhead on the Lessee's offshore platform in the North Cook Inlet Field. Buyer was required, at its own expense, to arrange to accept the gas at the point of delivery. However, Buyer has been unable to do so because it is not economically feasible to construct a pipeline to the point of delivery and because Buyer has been unable to reach agreement with the Lessee to use Lessee's existing pipeline to deliver the gas to a point on the North Kenai Road where Buyer could receive the gas. Lessee has been unwilling to transport the gas for Buyer

because to do so would place Lessee under the jurisdiction of the Alaska Public Utilities Commission and Lessee does not wish to become a public utility.

Current agreements provide for several provisions which deserve special consideration. They are as follows:

Quantity

The Buyer presently does not have markets for all royalty gas produced nor does the Lessee have the production capacity to produce enough gas to maintain required production at his LNG plant, in addition to producing all royalty gas. The Buyer and Lessee have therefore agreed that they will both use their "best reasonable efforts" to accomodate the other and that Lessee will produce and Buyer will sell that gas which is available.

If this agreement is not completed, the Buyer's market will have to be satisfied from reserves in the Kenai gas field which would be unnecessarily depleted, and royalty gas produced from Lessee's field would be delivered to his market outside the State of Alaska.

The Lessee will be installing compressors to maintain current production rates and to accomodate production of royalty gas. However, as the field well pressure continues to decline, the ability to produce the total required gas will correspondingly decline. Since the Lessee is required to maintain production for the LNG plant, the Buyer has agreed to allow any production shortfall to be taken from that quantity of gas dedicated to Buyer.

However, it is also reasonable to expect that productivity in the field will be sufficient to accomodate the needs of the Buyer for most of the life of these agreements.

Delivery - Compression

The Lessee has agreed to deliver the gas purchased by Buyer, by utlitzing Lessee's pipeline facilities, to a point near the North Kenai road. The compression facilities necessary to increase field production will be installed by Lessee to accomodate this increased demand.

The Buyer previously agreed with Lessee that the cost of delivery shall be 10¢ per MCF and that the cost of compression shall be an additional 10¢ per MCF. These costs are paid directly from Buyer to Lessee for the account of the State. Should additional compressors be required during the life of these agreements the new charges must be agreed to or the contracts will terminate. It is further understood that Buyer's alternative source of gas would cost the same as royalty gas delivered to the same point.

Price

The State will at all times during the life of the agreements receive at least as much and perhaps more for its royalty gas as it would have received if it had taken its royalty in-value.

Public Utilities Commission/Alaska Pipeline Commission

A major reason the previous agreement failed was because Lessee would be subject to the jurisdiction of the above

mentioned regulatory agencies. The current agreements have been designed to avoid this problem as the only way that the producer would agree to transport the gas. The legal opinions relating to this matter were requested from the Attorney General and are enclosed to support these agreements.

The regulatory agencies would normally audit such costs as the delivery and compression charges to be paid by the Buyer to Lessee. However, in this case the Buyer and Lessee had agreed to these charges prior to the development of the current agreements. It is evident that had the previous agreement become operational, these same charges would have been applied to this gas.

E X H I B I T

1.

Gas Purchase Contract

dated June 4, 1976 between

Alaska Pipeline Company

and

State of Alaska

Gas Purchase Contract

This Contract, made and entered into this 4th day of June 1976, by and between the Alaska Pipeline Company ("APC") herein referred to as "Buyer" and the State of Alaska, hereinafter referred to as "Seller" :

WITNESSED

WHEREAS, Buyer owns and operates a natural gas pipeline system in areas of Alaska for the delivery of natural gas for ultimate consumption within the State of Alaska, and

WHEREAS, Seller has the right under each of the leases identified at Exhibit "A" attached hereto to be paid by the lessee thereunder a royalty of twelve and one-half percent in kind or in value of the natural gas produced and saved and used off of the lands covered by each such lease, and

WHEREAS, Seller is authorized by AS 38.05.183 to sell royalty gas; and

WHEREAS, Buyer represents to Seller that all gas purchased under this contract will be used to meet the requirements of its customers within the State of Alaska;

NOW, THEREFORE, in consideration of the representations, covenants, and conditions herein contained, Buyer and Seller hereby agree as follows:

ARTICLE 1

Seller's Royalty Gas

1.1 Seller hereby agrees that within 30 days after the execution and approval of this agreement as required by the laws of the State of Alaska, Seller shall notify the lessee under the leases set forth at Exhibit "A" of this agreement of Seller's election to take its royalty gas in kind. Said notice will provide that the lessee shall commence the delivery of said royalty gas to Seller (or to Seller's designee) upon a receipt of notice from Seller that all facilities necessary to enable Buyer to receive and market said gas are ready; provided, however, in no event shall lessee be required to commence the delivery of royalty gas to Seller (or its designee) prior to six (6) months following lessee's receipt of notice of Seller's election to take its royalty gas in kind.

1.2 In order that Seller can give its lessee as much advance notice as possible of the date it will start receiving its royalty gas in kind, Buyer shall notify Seller, and Seller shall notify its lessee, at least 60 days prior to the date Buyer will receive gas from Seller pursuant to this contract.

ARTICLE II

Quantity

2.1 It is understood and agreed by the parties that the volume of gas available to Seller from the leases covered by this contract depends upon the production from the leases over which Seller has no control. Buyer hereby agrees to purchase on each day commencing with the date of first delivery

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hereunder and continuing during the term of this contract all of Seller's royalty gas available at the point of delivery described in Article III hereof.

ARTICLE III

Delivery Point and Delivery Pressure

3.1 The point of delivery of all gas delivered hereunder shall be at the same point of delivery that Seller receives delivery of its royalty gas from its lessee in the North Cook Inlet Field.

3.2 Buyer, at its own expense, shall arrange to accept Seller's gas at the point of delivery.

3.3 Seller will deliver gas received by Seller from lessee at the pressure at which the gas is received by Seller from its lessee.

ARTICLE IV

Quality

4.1 The gas to be delivered by Seller to Buyer at the delivery point shall be gas of the same quality as is delivered to Seller by the lessee at the point of delivery.

ARTICLE V

Price and Billing

5.1 The price to be paid by Buyer to Seller for gas delivered shall be as follows:

a. Commencing on the date of first deliveries hereunder, assuming that this date occurs prior to July 1, 1977 and continuing until the first day of July 1977, the price shall be 55.5 cents per MCF.

b. Commencing on the first day of July 1977 and continuing until the first day of July 1978 the price shall be the higher of (i) 60.36 cents per MCF, (ii) the price Seller would have received from Phillips Petroleum Company had it not elected to receive its royalty gas in kind, (iii) the highest price paid by any purchaser in the upper Cook Inlet area for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges.

c. For each succeeding 12 month period commencing July 1, 1978 the price shall be increased to the higher of (i) the previous year's price plus 2 cents per MCF, (ii) the price Seller would have received had it not elected to take its

royalty in kind, (iii) the highest price paid by any purchaser in the upper Cook Inlet area for gas of similar quality and conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges.

5.2 Thirty days prior to the date of each annual price change, Seller, at its option, may determine the price which it would have received from its lessee had it not elected to take its royalty gas in kind and the highest price being paid for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges in the upper Cook Inlet area and submit the same to Buyer along with suitable supporting evidence as to such prices. Buyer shall have the right to submit other evidence within the 30 day period.

5.3 After the delivery of gas has commenced Buyer shall, on or before the 20th day following the end of each month, render to Seller a statement showing the quantity of gas delivered during that month and shall therewith pay Seller the amount due for all such gas.

5.4 Each party hereto shall have, at its expense, the right to examine the books and records of the other party to the extent necessary to verify the accuracy of any statement, charge, computation, or demand made under or pursuant to this

contract. Any statement shall be final as to both parties unless questioned in writing within two (2) years after payment thereof has been made.

5.5 The terms "upper Cook Inlet area" as used here in shall mean the area encompassed in a radius of 100 kilometers from the Phillips Petroleum North Cook Inlet platform.

ARTICLE VI

Term

6.1 This contract shall become effective upon the execution hereof and the approval of the Alaska Royalty Oil and Gas Development Advisory Board and the State Legislature and shall continue and remain in effect until July 1, 1984, unless terminated prior to such date by mutual agreement of the parties, or pursuant to Article VII.

ARTICLE VII

Conditions Precedent

7.1 Buyer shall have the right to terminate this contract upon 30 days written notice to Seller if Buyer is unable to make satisfactory arrangements to take delivery of the gas. Buyer shall exercise this right to terminate on or before January 31, 1978, thereafter Buyer may not exercise this right to terminate.

ARTICLE VIII

Notices

8.1 Notices required to be given under this contract shall be deemed sufficiently given and served when and if

deposited in the United States mail postage prepaid and certified or registered addressed to Seller at:

Commissioner
Department of Natural Resources
Pouch M, Juneau, Alaska 99811

or to Buyer at:

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in four (4) original counterparts on this day and year first above written.

"BUYER"

Harold B. Schmidt

STATE OF ALASKA

Guy R. Martin

ATTEST:

Richard F. Barner

ATTEST:

William C. Fackler

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E X H I B I T

2.

North Cook Inlet Field Royalty Gas
Commissioner's Proposal in Concept

The Commissioner of Natural Resources has recognized that the increasing growth of the Cook Inlet area of Alaska with its resultant increase in the use of natural gas requires that additional natural gas reserves be allocated for that purpose from State of Alaska royalty gas. From the standpoint of size of uncommitted gas reserves, geographical location and possible pipeline access, the North Cook Inlet field royalty gas appears the best available supply at this time. Pursuant to AS 38.05. 182 the Commissioner proposes that it is in the best interest of the State to take in kind the State's royalty share of the gas production from the North Cook Inlet gas field and requests the consent of the Alaska Royalty Oil and Gas Development Advisory Board for this change.

* see Hammond's letter attached

The Commissioner further proposes to dispose of the North Cook Inlet field royalty gas to Alaska Pipeline Company and its subsidiaries through a negotiated contract. The proposed contract will contain the following provisions:

1. Purchaser agrees to take 1/8 of daily production from the North Cook Inlet gas field on an if and as deliverable basis for the contract period. The State will report to the Purchaser each month the amount of royalty gas produced by Phillips during the prior months.

The approximate average daily royalty gas share of the production from Phillips' North Cook Inlet field platform is 17,000 MCF. Gas production from the platform varies as LNG plant needs dictate therefore no daily amount can be specified.

2. Point of delivery will be the wellhead.

3. Purchaser is responsible for measurement costs, and any compression or dehydration costs if or when necessary.

4. The contract expires on June 1, 1984, unless extended by mutual agreement for a period not to exceed one year.

5. The price of the gas will be equal to the price the State otherwise would have received from Phillips for its royalty gas for export as LNG to Japan; but not less than the highest price paid by any purchaser in the Cook Inlet area for a similar sale of gas of similar quality. The price will be adjusted yearly on the anniversary date of the contract.

6. The contract shall not be effective until

-all necessary permits and authorizations by governing bodies are obtained

-all transportation or exchange arrangements have been completed to the satisfaction of the parties involved.

-six month's notice required under lease

The Commissioner request approval of the above proposed conceptual plan by the Alaska Royalty Oil and Gas Development Advisory Board.

E X H I B I T

3.

RECEIVED
MAY 05 1976
ALASKA ROYALTY
OIL & GAS BOARD

Introduced: 5/4/76
Referred: Resources and Finance

IN THE HOUSE SCR106 BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

HOUSE CONCURRENT RESOLUTION NO. 142

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINTH LEGISLATURE - SECOND SESSION

Relating to the taking of state-owned royalty oil or gas in-kind and its disposal by sale.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the legislature by enactment of the Alaska Royalty Oil and Gas Development Board statute, AS 38.06. et seq., has established a clear policy of favoring the taking of state-owned royalty oil or gas in-kind and making that royalty available for in-state uses; and

WHEREAS the State of Alaska presently receives a one-eighth royalty on gas produced from the North Cook Inlet Gas Field in value, but has the right to receive this royalty in-kind; and

WHEREAS the commissioner of natural resources has entered into a contract for the sale and purchase of state-owned royalty gas from the North Cook Inlet Gas Field with Alaska Pipeline Company, an Alaskan corporation which sells natural gas in the Anchorage and North Kenai Road areas; and

WHEREAS the contract between the State of Alaska and Alaska Pipeline Company requires as a condition precedent to its becoming effective approval by a majority of each house of the Legislature;

BE IT RESOLVED by the Alaska State Legislature that approval of Alaska Royalty Gas Sale No. 76-1, the contract for the sale of state royalty gas from the North Cook Inlet Gas Field to Alaska Pipeline Company, is hereby approved.

AGO 801377

E X H I B I T

4.

April 30, 1976

The Honorable Mike Bradner
Speaker of the House
Alaska State Legislature
Pouch V
Juneau, Alaska 99811

Transmittal of Proposed
Alaska Royalty Gas Sale No. 76-1

Dear Mr. Speaker:

Attached is Alaska Royalty Gas Sale Contract No. 76-1 providing for a sale of State royalty gas from the North Cook Inlet Gas Field to Alaska Pipeline Company pursuant to AS 38.96 et seq., AS 38.05.182-183, and 11AAC26.005-.900. Also attached are all necessary waivers or consents related to this action and required under the law. The contract and all necessary related actions have been approved by the Alaska Royalty Oil and Gas Development Advisory Board pursuant to the above statutes and regulations. Other information pertinent to the proposed sale is also attached, with the intention of supplying you with an adequate record on this matter.

Alaska Pipeline Company, and its subsidiary Alaska Gas and Service Company, supply natural gas to the Anchorage area and a portion of the North Kenai peninsula known as the North Kenai road area. Increased use of natural gas due to growth in both areas is diminishing the gas reserves dedicated to Alaska Pipeline Company faster than anticipated. The company estimates that the contract amount for the North Kenai road area will be exhausted by May of this year and has executed a one year contract with their present supplier to extend their service.

Natural gas from the North Cook Inlet Gas Field, operated by Phillips Petroleum Company, is transported from the offshore platform to the LNG plant in the Nikiski area served by the North Kenai road and liquified for export to Japan.

AGO 801379

The proposed contract provides that the State of Alaska will take its royalty share of the North Cook Inlet Gas Field production in kind rather than in value, and sell this gas to Alaska Pipeline Company at the same price that the State would otherwise receive from Phillips Petroleum Company. The amount of gas sold would average 15 to 16 million cubic feet per day and total about 41 billion cubic feet over the term of the royalty sales contract, which would expire June 1, 1984, coincidentally with the expiration of the present Phillips contract for export to Japan. Transportation or exchange provisions will be arranged by Alaska Pipeline Company, as will all necessary regulatory clearances.

The present peak gas demands along the North Kenai road can be as high as 10 million cubic feet per day. Gas excess to these needs can be used to augment the gas supply to Anchorage and extend the life of those reserves.

The total contract amount represents about one and one-half year's supply of gas at Anchorage's present rate of use, and about one year's production of the North Cook Inlet Gas Field.

The Commissioner of Natural Resources and the Alaska Royalty Oil and Gas Development Advisory Board recognize that the proposed sale of royalty gas will somewhat shorten the productive life of the North Cook Inlet Gas Field by approximately one year. Since the LNG contract requires delivery of a specified amount each year it will be necessary to increase the daily production of the field by the amount of the royalty gas withdrawn from the LNG plant. On balance, however, the sale of this royalty gas to supply the North Kenai road area and Anchorage is deemed to be in the best interest of the State, as it returns State royalty gas from foreign export to Alaska consumers at a price which assures all Alaskans a fair return for their resources.

I have, at various times, expressed the belief that section 55 of the Royalty Board Statute (which requires legislative approval by concurrent resolution of any sale of surplus royalty gas) is unconstitutional. The Administration believes that this requirement raises a substantial constitutional question and has concluded that in the future appropriate action will be necessary either by the Legislature to amend the Royalty Board Statute or by the courts to decide the constitutionality of

section 55. Notwithstanding such doubts concerning the constitutionality of this provision, the contract is being submitted to the Legislature for approval. Two reasons support this submission. First, early in this session, the Commissioner of Natural Resources advised the Legislature of his intent as a policy matter to carry out all the requirements of the Royalty Board Statute. I believe it would be less than forthright to pursue any other course for a sale during the closing days of the legislative session. Second, although this sale involves a relatively small quantity of gas, I am anxious to see it consummated at the earliest possible time as it will directly and immediately benefit gas consumers in the Anchorage and North Kenai areas. For that reason, it is undesirable that this contract become entangled in litigation which might extend over a lengthy period of time.

To avoid the choice of either appearing to acquiesce in the requirement of legislative approval or undertaking a perhaps unnecessary confrontation, a term has been included within the contract which provides that the contract will not become effective until approved by concurrent resolution passed by a majority of each house of the Legislature. The Administration always has the right to seek the advice and counsel of the Legislature and I have in this contract sought to make legislative approval a condition precedent to the contract becoming effective. I am submitting this contract to you for your approval pursuant to that term. However, in doing so, I wish to make clear beyond preadventure that my action should not be construed as either approval of or acquiescence in section 55 of the Royalty Board Statute and that I do not feel personally or legally obligated to submit future contracts for the sale of royalty oil or gas to the Legislature for approval by concurrent resolution.

You are aware that this is the first royalty sale contract prepared under the existing Statute, and of the first of its kind in the Nation. The Commissioner of Natural Resources, who is the official responsible for the agreement, is prepared to supply all necessary additional information to assist you in your consideration of this sale contract. Thank you for your consideration.

Sincerely,

Jay S. Hammond
Governor

Attachment

Natural Resources/WCF/dk/tdg

ALASKA PIPELINE COMPANY

Contract to Purchase State Royalty Gas

Findings and Conclusions of the Commissioner
Pursuant to Alaska Statute 38.05.183(c)

Alaska Statute, AS 38.05.183(c), requires that the Commissioner of Natural Resources make public, in writing, the specific findings and conclusions upon which a determination not to use competitive bid procedures is based for a sale of Alaska royalty oil or gas. Publication is to follow approval of the determination by the Alaska Royalty Oil and Gas Development Advisory Board. On April 6, 1977, the Royalty Board did approve the Commissioner's determination to waive the competitive bidding requirement for sale of royalty gas to the Alaska Pipeline Company by approving the contract entitled "Gas Purchase Contract" for gas, dated April 11, 1977, between the State of Alaska and Alaska Pipeline Company. Accordingly, these written findings and conclusions are submitted in fulfillment of the requirements of AS 38.05.183(c).

The Contract entitled "Gas Purchase Contract" dated April 11, 1977, between the Alaska Pipeline Company and the State of Alaska, as well as the agreement between the Phillips Petroleum Company and the State of Alaska, have been entered into because the Contract entitled "Gas Purchase Contract" dated June 4, 1976 could not become implemented.

The Findings and Conclusions for Non-Competive Sale for the previous Contract is appended to support the current Findings and Conclusions of the Commissioner not to use competitive bid procedures for these contracts.

Is HEA's offer not competitive?

The current agreements have been executed solely to solve these problems and allow royalty gas to be delivered to the Buyer.

The reasons for this determination not to use competitive bid are the same as the previous determination.

Findings and Conclusions for Non-Competitive Sale

Pursuant to AS.38.05.183 and AS.38.06 the findings and conclusions which form the basis for the decision that the sale of North Cook Inlet Gas Field royalty gas to Alaska Pipeline Company should be non-competitive sale are summarized.

1. Alaska Pipeline Company formerly Anchorage Natural Gas Company, is in need of additional natural gas supply. The present contract of 10 billion cubic feet to supply the North Kenai road area will be exhausted during the first half of 1976. Alaska Pipeline has executed an agreement recently with their supplier which enables them to use gas from the Anchorage contract reserves to supply the North Kenai area for one additional year. Projections of the present growth rate of Anchorage and use of natural gas indicate that the Anchorage contract dedicated gas supply could be exhausted several years before the contract termination at the end of 1992.

2. The proposed sale amount of royalty gas is sufficient to meet the needs of the North Kenai area for the term of the agreement. Present use of the North Kenai area is 10 million cubic feet per day. About 90% of this gas is used by the Bernice Lake electric generating plant of Chugach Electric Association. The difference between winter and summer loads is small. The North Cook Inlet Gas Field royalty gas share averages 15 to 16 million cubic feet per day. Gas in excess to the North Kenai area demand can be used to augment the Anchorage contract gas supply. The total volume of gas which would be sold under the proposed agreement is approximately 40 to 41 billion cubic feet.

3. North Cook Inlet Gas Field gas furnishes 70% of the gas supply of the Nikiski LNG plant, the remaining 30% is supplied by Marathon from the Kenai Gas Field. The LNG is shipped to Japan in cryogenic tankers and revaporized for use by Tokyo Gas and Tokyo Electric. At this time, the State is taking its royalty share in value and this gas brings the greatest return to the State of any royalty gas.

4. Proposed sale of this royalty gas will not diminish State revenue. Alaska Pipeline has agreed to pay the State the same price that the State otherwise would have received

from Phillips. Price terms in the proposed agreement are based on Phillips prices plus an agreement to pay a price equal to the highest price paid in Upper Cook Inlet for gas of similar quality and similar conditions of delivery.

5. The proposed action may reduce the productive life of the field equivalent to one year at the present rate of production. The total amount of gas sold under the agreement will be about 40 to 41 billion cubic feet per year. The present LNG contract dedicated reserves are 647,543 million cubic feet. Estimated original recoverable reserves were 1,500,000 million cubic feet. The estimated remaining gas reserves not committed to contract are about 834 billion cubic feet. The proposed sale involves about 5% of the remaining uncommitted reserves. Because the LNG sale contract requires delivery of 50,750 million cubic feet of gas per year to Tokyo, it will be necessary for Phillips to increase the field production by the amount withdrawn for royalty sale. While this increased production will shorten the producing life of the field, the amount of decrease is small and amounts to less than one year's production.

6. During the period of review of Alaska Pipeline Company's application for purchase of royalty gas applications were also made by Homer Electric Association, Pacific Alaska LNG and Phillips Petroleum.

   Homer Electric wished to buy the Bernice Lake generating facility from Chugach Electric and wanted to use the North Cook Inlet Gas Field royalty gas to supply the generator. This would be the same use proposed by Alaska Pipeline. Homer Electric subsequently advised the Alaska Royalty Oil and Gas Development Board that HEA had made satisfactory arrangements with the City of Kenai for a gas supply in the event it would be needed.

   Pacific Alaska LNG made a statement that they would be interested in bidding for the North Cook Inlet royalty gas if it were offered in a competitive bid sale.

   Later, Pacific Alaska advised the Board both by mail and in person that they were not making application for the North Cook Inlet royalty gas but rather a general statement applicable to possible future sales of other royalty gas.

Phillips Petorleum made a firm offer to purchase the royalty gas with an increase in price of five cents per thousand cubic feet (MCF) the first year, a similar increase the second year, and an annual escalation of two cents per MCF thereafter for the life of the present contract.

The withdrawals of Homer Electric and Pacific Alaska LNG left Phillips Petroleum as the only viable alternate to Alaska Pipeline's application.

CONCLUSION:

The decision to hold a negotiated sale rather than a competitive sale was based on several factors: end use, price to consumers, and future gas supply for Alaska.

The export of LNG to Japan has created a substantial market for Alaska's natural gas converting a non-revenue producing resource into a valuable asset with substantial revenues to the State.

The exported LNG produces about 75% of the State revenue from natural gas. While there was a reluctance to alter the use of the royalty gas and possibly necessitate additional costs to the LNG project, the use of the gas by the Kenai and Anchorage consumers was deemed to be a higher and better use.

Alaska Pipeline agreed to pay the State the same price the State otherwise would have received for the gas thereby maintaining the same revenue from the gas. While a competitive sale might have resulted in more revenue for the State it would also result in the gas being exported from the State and not available for Alaskan use. Alternately, if an Alaskan comapny was the successful high bidder it likely would set a new high price to the Alaskan consumer.

The present sale represents a balance of public values regarding this series of issues. The proposed non-competitive sale of North Cook Inlet Gas Field royalty gas appears to be in the best interest of the State as a whole and of the Kenai and Anchorage area gas consumers more directly. There is no loss of revenue to the State; the gas sale will be the gas supply for the North Kenai road area and add to the Anchorage area gas reserves; the slight loss of productive life of the North Cook Inlet Gas Field is offset by the continued service to the Alaskan gas consumers.

APPROVAL OF REQUEST OF COMMISSIONER
OF NATURAL RESOURCES
TO REJECT APPLICATIONS

WHEREAS, Alaska Statute 38.06.050(b) prohibits the rejection of applications for the purchase of royalty oil or gas by the Commissioner of Natural Resources ("Commissioner") without the approval of the Alaska Royalty Oil and Gas Development Advisory Board ("Board"), and

WHEREAS, the Commissioner in conjunction with his request for the sale of royalty gas to Alaska Pipeline Company requests that he be allowed to reject applications in conflict with the proposed sale, and

WHEREAS, this Board has reviewed all other applications for the purchase of royalty gas and heard public comment thereon,

NOW THEREFORE, this Board hereby grants its approval to reject applications to the extent such applications are rendered infeasible or impossible by the contracts for the sale of royalty gas approved by this Board on this date.

This approval relates to that certain agreement entitled "Gas Purchase Contract" between Alaska Pipeline Company and the State of Alaska dated this day of April 11, 1977.

Approve	Disapprove
[signature]	[signature]
[signature]	
[signature]	

Date: April 6, 1977

AGO 801387

APPROVAL OF THE AGREEMENT FOR THE TAKING AND GATHERING OF STATE ROYALTY GAS BETWEEN THE STATE OF ALASKA AND PHILLIPS PETROLEUM COMPANY

WHEREAS, Alaska Statutes 38.06.050(a) and 38.05.183 require that the Alaska Royalty Oil and Gas Development Advisory Board ("Board") grant to the Commissioner of Natural Resources ("Commissioner") written approval for the sale, exchang , or other disposition of royalty oil or gas, and

WHEREAS, Alaska Statute 38.05.182 requires that the Board grant its consent to the taking of royalty oil or gas in-kind, and

WHEREAS, the Board has been advised by the Commissioner of the progress of negotiations and has heard testimony, both in public sessions and working sessions, from the Lessee, and

WHEREAS, the Commissioner has now concluded his negotiations with the Lessee and has presented to this Board for its approval an Agreement for the sale of royalty gas from the North Cook Inlet (which gas is identified more specifically in the Agreement), and

WHEREAS, This Board has carefully reviewed the proposed agreement and has received public comment on the agreement, and

WHEREAS, This Board finds that the taking of royalty gas in-kind to meet the obligations under the agreement will serve an important public purpose and be of general benefit to the public interest,

NOW THEREFORE, the Alaska Royalty Oil and Gas Development Advisory Board hereby grants its approval of the Agreement between the State of Alaska and Phillips Petroleum Company and further approves the taking in-kind of the royalty gas dedicated to this agreement.

This approval relates t) that certain "Agreement" to take in-kind royalty gas from the North Cook Inlet between the State of Alaska and Phillips Petroleum Company. Dated April 11, 1977.

Approve	Disapprove
Glen M. Taylor	Vincent D. Wright
Le Resche	

Date: April 6, 1977

APPROVAL OF THE AGREEMENT FOR THE PURCHASE AND SALE OF STATE ROYALTY GAS FROM THE NORTH COOK INLET FIELD BETWEEN THE STATE AND ALASKA PIPELINE COMPANY

WHEREAS, Alaska Statutes 38.06.050(a) and 38.05.183 require that the Alaska Royalty Oil and Gas Development Advisory Board ("Board") grant to the Commissioner of Natural Resources ("Commissioner") written approval for the sale, exchange or other disposition of royalty oil or gas, and

WHEREAS, Alaska Statute 38.05.182 requires that the Board grant its consent to the taking of royalty oil or gas in-kind, and

WHEREAS, the Board has been advised by the Commissioner of the progress of negotiations and has heard testimony, both in public sessions and working sessions, from the purchaser, and

WHEREAS, the Commissioner has now concluded his negotiations with the purchaser and has presented to this Board for its approval an agreement for the sale of royalty gas from the North Cook Inlet field (which gas is identified more specifically in the Contract), and

WHEREAS, This Board has carefully reviewed the proposed agreement and has received public comment on the agreement, and

WHEREAS, This Board finds that the taking of royalty gas in-kind to meet the obligations under the agreement will serve an important public purpose and be of general benefit to the public interest,

NOW THEREFORE, the Alaska Royalty Oil and Gas Development Advisory Board hereby grants its approval of the "Gas Purchase Contract" between the State of Alaska and Alaska Pipeline Company and further approves the taking in-kind of the royalty gas dedicated to this agreement.

This approval relates to that certain agreement entitled "Gas Purchase Contract" between the Alaska Pipeline Company and the State of Alaska dated this day of April 11, 1977.

Approve	Disapprove
Ken M Tompleton	Vincent D. Wright
P LeResche	

Date: April 6, 1977

AGO 801389

APPROVAL OF REQUEST OF COMMISSIONER OF NATURAL RESOURCES
TO WAIVE REQUIREMENT OF COMPETITIVE BIDDING

WHEREAS, Alaska Statutes 38.06.050(c) and 38.05.183 (a) and (c) require the Alaska Royalty Oil and Gas Development Advisory Board ("Board") grant written approval to the Commissioner of Natural Resources ("Commissioner") to waive the requirement that royalty oil or gas be sold by competitive bid, and

WHEREAS, the Commissioner has submitted to this Board a request to waive the requirement of public bidding with respect to royalty gas from the North Cook Inlet Field, and

WHEREAS, the Board has considered the request of the Commissioner and finds the Commissioner's reasons sufficient to justify a waiver of the requirement for public bidding in the public interest;

NOW THEREFORE, the Alaska Royalty Oil and Gas Development Advisory Board hereby grants to the Commissioner of Natural Resources its approval of his request to waive public bidding.

This waiver relates to that certain agreement entitled "Gas Purchase Contract" between Alaska Pipeline Company and the State of Alaska dated this day of April 11 1977.

Approve	Disapprove
[signature]	[signature]
[signature]	
[signature]	

Date: April 6, 1977

AGO 801390

STATE of ALASKA

MEMORANDUM

File: APUC Phillips Ak Pipe Co.

TO: Guy Martin, Commissioner
Dept. of Natural Resources

DATE: March 7, 1977

FILE NO:

TELEPHONE NO:

FROM: Wilson Condon
Deputy Attorney General

SUBJECT: Jurisdiction of the APUC over Phillips Petroleum Pipeline

This is in response to your memorandum of February 24, 1977, in which you ask if the Alaska Public Utilities Commission would have jurisdiction over a pipeline operated by Phillips Petroleum if State-owned royalty gas is transported over that pipeline to North Kenai Road, where it would be sold by the State to Alaska Pipeline Company, a wholly owned subsidiary of Alaska Gas and Service. My conclusion is that the APUC would not have jurisdiction over the Phillips Petroleum Company pipeline.

The Alaska Public Utilities Commission has jurisdiction over "public utilities" which are defined by AS 42.05.70(2) as follows:

> "public utility" or "utility" includes every corporation (whether public, cooperative, or otherwise), company, individual, or association of individuals, their lessees, trustees, or receivers appointed by a court, that owns operates, manages or controls any plant, pipeline or system for
>
> * * *
>
> (D) furnishing by transmission or distribution of natural or manufactured gas to the Alaska public for compensation;
>
> * * *

"Public" is defined by AS 42.05.701(5) as follows:

> "public" or "general public" means
>
> (A) any group of 10 or more customers that purchase the service or commodity furnished by a public utility as defined in (2) of this section; and
>
> (B) any utility purchasing the product or service or paying for the transmission of electric energy, natural or manufactured gas, or petroleum products which are resold to a group included in (A) of this paragraph or which are used to produce the service or commodity sold to the public by the utility.

If Phillips delivers royalty natural gas to the State at the wellhead, and the State contracts with Phillips for transportation of that gas to North Kenai Road, Phillips will be rendering a utility-type service because it will be engaged in the transmission of natural gas. Phillips, however, will be neither a "utility" nor "public utility" within the meaning of the Public Utilities statute because it will not be furnishing transmission service to the "public" or the "Alaska public." Phillips would be furnishing transmission service to the State. This would make it a public utility if 1) the State is the 10th customer to purchase transmission service (our assumption is there are less than 10 purchasers of transmission service), or 2)if the State is a "utility. . . paying for the transmission of. . . natural. . . gas. . . which is resold to [any group of 10 or more customers that purchase the service or commodity furnished by a public utility. . .]." The State would not be a utility (because it does not fit within the definition of AS 42.05.701(2)), thus Phillips could not be a public utility subject to the jurisdiction of the APUC when it furnishes transmission service to the State.

WLC:FHB:bvd

cc: Frederick H. Boness
Assistant Attorney General

Robert E. Stoller
Assistant Attorney General

STATE
of ALASKA

MEMORANDUM

TO: Don Wold
Executive Director
Alaska Royalty Oil and Gas
Development Advisory Board

DATE: March 29, 1977

FILE NO:

TELEPHONE NO:

FROM: Wilson Condon
Deputy Attorney General

SUBJECT: Jurisdiction of the Alaska Pipeline Commission Over Phillips East Cook Inlet Gas Line

This is in response to your memorandum of March 11, 1977 in which you ask if the Alaska Pipeline Commission (APC) would have jurisdiction over a pipeline operated by Phillips Petroleum if State-owned royalty gas is transported over that pipeline to North Kenai Road, where it would be sold by the State to Alaska Pipeline Company, a wholly owned subsidiary of Alaska Gas and Service. My conclusion is that the APC would not have jurisdiction over the Phillips Petroleum Company pipeline.

The Alaska Pipeline Commission has jurisdiction over "pipelines", "pipeline facilities" and "pipeline carriers". AS 42.06.630(10) defines "pipeline carrier" as:

> . . . the owner, including corporations . . ., of any pipeline, as the term is defined in this section, or any interest in it;

AS 42.06.630(9) defines "pipeline" or "pipeline facility" as:

> . . . all the facilities of a total system of pipe . . . in this state used by a pipeline carrier for transportation, for hire and as a common carrier, of oil or gas for delivery, storage, or further transportation, and including all pipe, pump and compressor stations, station equipment, and all other facilities used or necessary for an integral line of pipe to effectuate the transportation from point to point, excluding, however, gas processing plant, heaters and separators;

The salient portion of the above definition is written in the conjunctive, i.e., to be a "pipeline" or "pipeline facility" under the Alaska Pipeline Commission Act, AS 42.06 et seq., a pipeline facility must be used ". . . for transportation, for hire and as a common carrier . . ." (emphasis added).

Of course Phillips, in the arrangement described at the outset of this memorandum, will be using its pipeline for "transportation" of gas. However, since the subject pipeline is neither operated by Phillips "as a common carrier" nor is it subject to the "common carrier" covenant requirement of AS 38.35.120 due to the fact that the lease of state lands for the subject pipeline pre-dates the enactment of that statute, the subject pipeline would not fall within the jurisdiction of the APC were the proposed arrangement to be entered into by Phillips.

WLC:RMB:jec

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 Anchorage, Alaska 99502 / Phone (907) 277-5551
Telex 25-187

April 15, 1977

Mr. Don Wold, Executive Director
Alaska Oil and Gas Development Advisory Board
Department of Natural Resources
State Office Building
Juneau, AK 99811

Dear Don:

In response to your requests this week, we are writing to summarize and describe the essence and the effect of the contract(s) executed by the State and Phillips and Alaska Pipeline Company (APC) regarding the taking in kind of the State's royalty gas (1/8th) from the North Cook Inlet Gas Field.

By way of background, APC's supply until now has come entirely from the Kenai gas field, which is owned by Union and Marathon. We have had two supply contracts: one for Anchorage, in which delivery to us is at the Kenai gas field; and one for the North Kenai Road ("Nikiski") area, in which delivery to us is at or near the Kenai LNG plant.

The "Anchorage" contract is for a total of 550 BCF (billions of cubic feet) to be taken (take or pay for) at 26 BCF/year (which is 72,000 MCFD--72,000 thousand cubic feet per day) by December 31, 1992, but with deliverability of 160,000 MCFD on any day through December 31, 1985. The basic price for this gas is 24¢ per MCF until January 1, 1981, then 27¢ until January 1, 1986, and then the defined "area price" for the remainder of the contract term. In addition to this basic price we pay 19.5¢ per MCF for the extra deliverability described above, and the

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 / Anchorage, Alaska 99502

19.5¢ is adjusted each January 1 by the ratio of the published Wholesale Price Index (WPI) of the preceding November to the WPI of November, 1974. At present, the total cost for gas under this "Anchorage" contract is 45.1¢ per MCF.

The "Nikiski" contract was for 10 BCF to be delivered from May 1, 1967 to April 30, 1977, with deliverability of 10,000 MCFD, no take or pay, and priced at 1.5¢ higher than the basic price for "Anchorage" reserves as described above. We used the last of the 10 BCF under this contract in August of 1976, and thereafter we began taking "Anchorage" reserves at Nikiski, priced at the total price of "Anchorage" reserves plus 1.5¢ per MCF, temporarily (one year was agreed) pending resolution of a longer term supply. We had expected to be using North Cook Inlet royalty gas as the replacement for "Anchorage" reserves at Nikiski, and still expect to be doing so upon the implementation of the royalty gas contracts as revised this year.

We selected North Cook Inlet royalty gas because we believed, and still believe, this gas will be available to us and our customers at a lower price than any other "new" reserves. This gas is under contract (as LNG) to June 1, 1984 for export to Tokyo and its cost to us is approximately 75¢ per Mcf immediately, rising to 85¢ when compressors are installed, with certain escalation as described in the revised contracts. In comparison, Pacific Alaska LNG is offering $1.45 for similar gas from Cook Inlet (without the same deliverability of our "Anchorage" reserves), with escalations. We do not have proof of the $1.45 pricing, but it can be verified by the State. Thus, we see the royalty gas to be available

to us at less than half the going price of "new" gas in the Cook Inlet area, delivered on the North Kenai Road.

Our alternative to competing at the $1.45 price level is to continue to utilize "Anchorage" reserves at Nikiski, as we are now doing, but to pay the same price we would have paid for royalty gas. We have verbal assurance that we can operate on this basis at Nikiski while we install the facilities necessary to shift to royalty gas, and we are proceeding with preparations to do so at the earliest possible date following legislative approval of the royalty contracts as revised. We hope to begin taking royalty gas as early as June, 1977.

Several questions arose over the two years it has taken to reach agreement of the several parties as to our use of royalty gas, and I will try to comment as information for those who review the actions taken. First, the royalty gas contract signed last year, and approved by the legislature, was contingent on APC working out an arrangement with Phillips to obtain delivery of the royalty gas through their pipeline from the platform to the Kenai LNG plant, and it required "take or pay" of 100% of the royalty gas. These elements led to problems which had to be resolved as has been done in the revised contracts which were executed last week. The differences are (1) that the delivery to shore will be made by Phillips for the State, with APC paying Phillips for the account of the State, at prices negotiated by APC with Phillips, and (2) that there will be no "take or pay": Phillips will make a best effort to deliver at least 3 BCF per year (roughly 55% of the total royalty), and APC will make a best effort to take all of the royalty which Phillips

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 / Anchorage, Alaska 99502

can deliver, but neither party will be obligated to make extra investment or incur unreasonable extra operating cost.

Without obligation, APC expects Phillips to deliver essentially all the royalty and expects to take all the royalty, but only experience will tell the outcome of this expectation. Phillips may install one or more units of compression, and APC may install a pipeline to connect the royalty gas into its pipeline to Anchorage. Various factors outside the respective control of Phillips and APC have made it necessary to develop a best-efforts arrangement rather than the original "take or pay" of 100% of the royalty.

APC's royalty pipeline, if built, would provide several advantages:

1. It would essentially assure APC's ability to take all of the available royalty, all of the time, and gain the maximum benefit from royalty gas.
2. It would provide "back-up" for APC's North Road customers while royalty gas may not be available due to downtime of the LNG plant, the platform, or the Phillips pipeline or compressors.
3. It would provide APC with access to other than royalty gas in the vicinity of the Kenai LNG plant, which is at the center of several streams of natural gas--supplies to Swanson River for repressurizing, ammonia/urea manufacture, Pacific Alaska LNG, etc. Thus, the pipeline could give APC additional options on "new" gas from various sources.

ALASKA PIPELINE COMPANY

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4. It would provide an independent supply of gas to APC for emergency in the event of catastrophic failure of the Kenai gas field--well operations, dehydration, or compression--or of APC's pipeline from the field to Mile 16 of APC's pipeline to Anchorage.

Feasibility of the royalty pipeline depends on the possibility of exchanging royalty gas with Union-Marathon, final rate decisions of the Alaska Public Utilities Commission (APUC), final quantification of the amount of royalty gas to be delivered, flow through of the extra cost of royalty gas, and other factors including availability and cost of right of way. At present it appears that there is sufficient benefit from the royalty line to justify the investment by APC.

APC's experience with the APUC is such that royalty gas is particularly attractive: the flow through of its extra cost to end users has been authorized by the APUC, whereas no other purchase by APC can be made with flow through except by further hearings. This fact, plus the fact that it appears royalty gas will always be available (for the contract term) at less cost than any other likely "new" gas, make the royalty most advantageous to APC and its customers. Further, the precedent of this purchase of this royalty gas by APC should be helpful at a future date when other royalty gas may become available and feasible for purchase by APC.

It is clear that APC's action to purchase royalty gas is in the public interest. The price is the lowest available to APC and its

customers; the price is qualified to be not less than the State would have received by its continued export to Japan or by any comparable sale during the contract term within 100 kilometers of the Phillips platform; and a relatively modest investment is required by APC even including the royalty pipeline. Other "new" gas could involve meeting the currently competitive price of Cook Inlet gas ($1.45) and could involve pipeline costs or take or pay costs many times that for royalty gas. The quantity of this royalty gas is rather ideal for APC's present requirements. In 1976, APC's total purchases were 28.6 BCF compared to the required take or pay quantity of 26 BCF per year at the Kenai gas field. As structured, the royalty gas contracts would allow APC (and Phillips) to match their investment to market developments and thus provide the optimum conditions for such investment.

Clearly, Phillips has been a reluctant party in these contracts but has acted responsibly and reasonably and consistent with the public interest. Phillips preference has always been to retain the royalty gas and increase its value by liquefaction for export to Japan. That contract was originally 52¢ FOB Tokyo, but now is $1.95. Clearly the increase ($1.43) contains a substantial increase of profit (which is shared by the State through its royalty price). Clearly the 20¢ revenue which Phillips will realize by bringing the royalty gas on shore does not compare with the revenue and income Phillips would realize by its export.

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The 20¢ delivery/compression charge is obviously the most Phillips could charge, because it is the most APC would pay. The State is realizing the most it can from the royalty gas, because APC will not pay more for this gas. To suggestions, if any, that APC should not have accepted the delivery charge as contracted, APC would respond that it would be no more logical to require Phillips to accept less than their required price than for the State to accept less than it deems to be necessary for this gas.

APC will not increase its income by purchasing this royalty gas--it will simply recover most (not all) of its costs, by flow through. APC's objective in making this purchase is to prolong the life of its gas reserves and thus the availability of its "old" gas at "old gas pricing" for its customers.

APC firmly believes that the merit of its purchase of royalty gas has been established already in various arenas.

1. The APUC considered the subject in extensive hearings in 1975 and its order clearly contemplates the purchase and in fact, deemed the matter to be of urgent importance.
2. The Royalty Board and the Commissioner of Natural Resources have reviewed this matter at great length and have approved and authorized its present form.
3. The Attorney General has reviewed jursidictional aspects and agreed it is not contrary to the public interest or the laws of Alaska.

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4. The legislature, in its prior approval, has endorsed the concept and pricing of this purchase by APC.

Previously, support for this purchase by APC was given by the City of Anchorage, Chugach Electric Association, and Homer Electric Association. APC is not aware of any opposition to its purchase of this royalty gas (opposition by Pacific Alaska LNG was withdrawn in 1976, at the insistence of APC). When these various governmental and business approvals are considered, and when the alternative can only be that this gas would continue to be exported to Japan, APC believes that ample justification for the contracts has been made.

At present, APC has about 415 BCF of gas remaining under contract at the Kenai gas field. At 30 BCF per year, there would be 14 years of reserves now remaining. The royalty gas potentially available to June, 1984 is about 40 BCF, which is less than a 10% increase. APC is and has been attempting to reduce the growth rate of its gas sales through conservation measures such as waste heat recovery by power plants and by opposing and reducing the use of gas-generated electric heat. However, it is very likely that unavoidable growth will shorten APC's reserve life to 10 years or less. APC must look to the long term aspects of its gas supply in order to avoid future shortages and problems with the long-term (20 year) financing APC requires. Purchase of the royalty gas is a step, but only a step, in this direction. Royalty gas at 75¢ or 85¢ will be helpful to APC in its negotiations for additional "new" gas reserves, viewed in the context of competitive offerings at $1.45 or possibly a price equivalent to oil in future years.

ALASKA PIPELINE COMPANY

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Delays in obtaining royalty gas can only diminish its benefit to APC and its customers because of the quantity available as well as the timing and impact of the purchase.

Very truly yours,

Dale Teel
President

DT/pm

Phillips

February 25, 1977

Mr. John Horn
Phillips Petroleum Company
Gas and Gas Liquids Division
Bartlesville, Oklahoma 74004

Dear Mr. Horn:

As you know, the State of Alaska entered into an agreement with the Alaska Pipeline Company on June 4, 1976 for the sale of the State's royalty gas produced from your company's North Cook Inlet Gas Field. The Alaska Pipeline Company and Phillips have been unable to work out a mutually satisfactory arrangement for delivery of the gas. The State of Alaska, through the Department of Natural Resources, is continuing to explore various ways this can be accomplished in the interest of all parties.

The Alaska Pipeline Company has proposed that the State enter into an agreement with your company to take delivery of royalty gas from your pipeline at a mutually agreeable point near the North Kenai Road. The State is presently exploring this possibility and your cooperation has been greatly appreciated. Several questions have been raised regarding this procedure. They are:

1. Will the Alaska Public Utilities Commission have jurisdiction over the Phillips pipeline if the State takes delivery at this point? The State's Attorney General has been asked for an opinion.

2. What charges would be made by Phillips for delivery of the gas to this point? What is the detailed justification of these charges?

3. We understand that as the field pressure declines, compressors will be installed to maintain production rate. What costs will be incurred by the State and what is the detailed justification of these costs?

4. What is your best forecast of the dates of installation of the first and future compressors and how will the cost to the State change with installation of additional compressors?

5. What is your best forecast of future production from this field? Will you share with the State your future production plans so that the State may plan accordingly to utilize its royalty gas?

6. The State understands your need to maintain production of your LNG plant and that your ability to deliver royalty gas to the State will change as the field pressure changes. Would you please explain this procedure and give us your best forecast of your ability to make delivery in the future?

Your response to the above would be greatly appreciated together with any further information that you may feel to be pertinent to the solution of this problem.

Would you please review the draft agreement prepared by Alaska Pipeline Company between Phillips and the State and recommend changes that may be of interest to your company?

Thank you for your cooperation. Your early response to the above will be greatly appreciated.

Very truly yours,

Donald G. Wold
Executive Director

DGW/jl

PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA 74004 918 661 6600

NATURAL RESOURCES GROUP
Gas and Gas Liquids Division

March 3, 1977

Royalty Gas
North Cook Inlet Field

File: 1-Ho-115-77-G&GL

Mr. Donald G. Wold, Executive Director
Royalty Oil & Gas Development Advisory Board
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Dear Sir:

In your letter of February 25, 1977, you have requested certain information regarding whether Phillips could make the royalty gas from the North Cook Inlet Field available at an onshore location on the North Kenai Road, rather than in the field as provided in our lease with the State of Alaska. Information is listed by the numbers used in your letter:

2. Q. What charges would be made by Phillips for delivery of the gas to this point? What is the detailed justification of these charges?

   A. Since we had previously negotiated a place differential of 10¢ per Mcf starting with the calendar year of 1977 and increasing 6% per year thereafter with Alaska Pipeline Co., Phillips would be willing to utilize this approach with the State. Although this is a negotiated figure, the data supporting same is shown on Table I.

3. Q. We understand that as the field pressure declines, compressors will be installed to maintain production rate. What cost will be incurred by the State and what is the detailed justification of these costs?

   A. For the first compressor unit (approximately 3800hp) installed, compression charge would be 10¢ per Mcf increasing 6% per year from the year of installation. As later units are added, the compression charge will be agreed upon at that time. The above charge is the result of negotiations with Alaska Pipeline Company and is on the condition that Royalty gas would be handled only when there is surplus capacity in our gathering system and compressors. The above charge would be substantially higher if based on adding sufficient additional compressor capacity to assure the availability of capacity and would also entail a substantial minimum annual payment to cover these additional costs. Our calculations are attached as Table II.

4. Q. What is your best forecast of the dates of installation of the first and future compressors and how will the cost to the State change with installation of additional compressors?

4. Continued.

A. This is dependent on the amount of royalty gas taken by the State and also on other factors, such as, whether LNG in addition to current deliveries to Japan is sold to the south 48 states. Based on present information, we estimate that the first unit would be installed in 1978 or 1979.

5. Q. What is your best forecast of future production from this field? Will you share with the State your future production plans so that the State may plan accordingly to utilize its royalty gas?

A. Production has averaged 43 to 45 Bcf annually over the last several years. We visualize that production could increase to 55 Bcf or more per year including royalty gas taken in kind.

6. Q. The State understands your need to maintain production of your LNG plant and that your ability to deliver royalty gas to the State will change as the field pressure changes. Would you please explain this procedure and give us your best forecast of your ability to make delivery in the future?

A. Without compression, the volume available from North Cook Inlet Field will decline rather rapidly commencing in 1979. Producing at the 43 to 45 Bcf per year rate and with the installation of compressors, these rates are estimated to continue until 1985, after which the volume declines approximately 10% per year. If the higher rate of 55 Bcf per year is maintained, the volume will commence declining in 1984 at the rate of approximately 10% per year.

You will appreciate that, due to the number of unknown factors, the information provided above is based on our best estimates of the situation as it now exists. New developments could change these estimates.

John Horn

JH:jaw

cc: R. I. Swetnam

TABLE I

PIPELINE

Estimated Present-Day Replacement Cost .....at least	$25,000,000
Estimated Present-Day Replacement Cost Depreciated to 1977	17,300,000

ESTIMATED COSTS

	$/Year
Depreciation (20 Years)	$1,100,000
Rate of Return 15% on Depreciated Investment	1,520,000
Income Tax @ 52.9% (State & Federal)	1,700,000
Operating Expense	2,750,000
TOTAL	$7,070,000

Cost/Mcf @ 43 Bcf/Year = 16.4¢

Cost/Mcf @ 55 Bcf/Year = 12.9¢

TABLE II

COMPRESSORS
(FIRST UNIT)

To maintain capacity in the gathering system and compressors to handle the full 12.5% royalty gas volume, it will be necessary to install compressors at an earlier date. Also, it is estimated that to maintain this capacity it will be necessary to install an additional compressor unit over and above that required for maintaining deliveries without the State taking its royalty gas in kind. Estimated differential in compressor investment is $5,000,000.

Cost of Compression

	$/Year
Depreciation (10 Years)	$ 500,000
Rate of Return 15% on Average Investment	375,000
Income Taxes @ 52.9% (State & Federal)	420,000
Operating Expense	715,000
TOTAL	$2,010,000

Minimum Annual Payment	= $2,010,000
Royalty Gas Volume @ 43 Bcf/Year	= 5.4 Bcf
Royalty Gas Volume @ 55 Bcf/Year	= 6.9 Bcf
Cost/Mcf @ 5.4 Bcf	= 37.2¢
Cost/Mcf @ 6.9 Bcf	= 29.1¢

Phillips agreed with Alaska Pipeline Company's request to a compressor charge of 10¢/Mcf on a space-available basis and no minimum annual charge.

General Offices Located at 3000 Spenard Road
P.O. Box 6247 / Anchorage, Alaska 99502

March 10, 1977

Memo to: File

Subject: Rationale for Accepting Gathering and Compression Charges Proposed on North Cook Inlet Royalty Gas

By telephone March 10, 1977 Mr. Don Wold asked us to rationalize the acceptance of a 10¢/MCF charge for "gathering" and a 10¢/MCF charge for compressing royalty gas we have negotiated to purchase from the State of Alaska.

The State will escalate the price we pay for royalty gas to the highest price paid by other purchasers within 100 kilometers for similar quality and similar delivery conditions. We had offered to pay no more than the price the State would otherwise have received through the continued export of the royalty gas to Japan as LNG.

It thus is clear that the State places the State's interest above the interests of our ratepayers to the extent we have to pay more than would result from export of this gas. It does not follow that the Lessee who has made the investment required for production, gathering, and compression of royalty gas can be or should be held responsible to deliver the royalty gas at less cost than the Lessee determines to be necessary, fair, and reasonable. In fact, efforts by the State to do so will simply result in there being no agreement and no delivery of royalty gas by the Lessee.

The Lessee cannot be treated as a regulated operator under Alaska law, and the Lessee has the right to determine whether or not, and at what price, it is willing to share its facilities and install new facilities for the benefit of our ratepayers rather than for its shareholders. Clearly, the Lessee prefers not to share these facilities and will not do so if effort is made to assert that delivery of royalty gas onshore could have equal or greater priority than its contractual duty to delivery LNG to Tokyo, regardless of the revenue (price) received by Lessee.

The Lessee has provided (letter of 3-3-77) some cost estimates, reluctantly, to show the reasonableness of the prices accepted by us:

Table I: Pipeline (Gathering)

Annual cost is reported to be $7,070,000. Assuming all this cost is carried by 43 BCF or 55 BCF, the average cost is 16.4¢ or 12.9¢. The selection of 10¢ as being appropriate for gathering

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royalty gas is less than these average costs, but clearly more than the incremental cost, as it must be. There is no way for a third party to impose a different price on the Lessee, and the price of 10¢ is far below any alternative available to us. In fact, there is no such alternative except not to take royalty gas, and we are not obliged to do so. We bear all the risk that the cost of this gas will remain competitive and will be recoverable through our revenues.

Table II: Compressors (first unit)

Annual cost is reported to be $2,010,000. Assuming all this cost is carried by 43 BCF or 55 BCF, the average cost is 4.67¢ or 3.65¢. While the compression is not required except to deliver royalty gas (but all the gas must be compressed), the incremental cost here would be 37.2¢ or 29.1¢. However, the Lessee recognizes that during the contract term compression will be required even if royalty gas is not being delivered to us. The selection of 10¢ as being appropriate for the compression is less than the short term incremental cost but well more than the average cost. Again, there is no way for a third party to impose a different price on the Lessee, and we bear all risk that the cost of this gas will remain competitive and will be recoverable through our revenues.

If the two components are combined, the results are:

$9,030,000 annual cost @ 43 bcfy

21.12¢ average cost

versus 20.00¢ price requested

The price requested is below the reported average cost. Assuming no incremental cost for gathering (pipeline) however, the price requested is well above the incremental cost. In fact, there is an incremental cost for gathering (as to dehydration), and other down-hole expenses which are a function of production rate. We are not equipped to quantify these costs and there is no reason to do so. The essence of this matter is that the Lessee has offered us a price below average cost and above incremental cost which is acceptable to us and that we are the only party at risk.

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There are only two beneficiaries of this contract. We do not benefit, since we will simply recover our added costs from our rate payers. We believe Phillips will not benefit since they are reluctant and clearly prefer to process and ship the gas to Japan. We believe their profits in processing and selling the royalty gas to Japan would be much greater than the amount of income from the proposed compression and transmission charges net of incremental expenses. The State takes no risks and may benefit from a higher wellhead price. Our ratepayers benefit from the increased life of our committed reserves. If the transaction is not consummated then, the losers are the State and our ratepayers, which (through power distribution) include more than half of the State's population, from Homer and Seward to Talkeetna.

There is no way to require the Lessee to deliver royalty gas (at any price) and no way to disagree with the price(s) now offered. Clearly the end objective -- obtaining of royalty gas -- is in the public interest, and the State should place that interest foremost.

dh

4/20/77

Notes—

— Contracts can be extended—that am added and new provision from the original 76-1 contract. Since this never was an item which prevented APC from taking delivery of the gas, why was it added? (14.1, line 17 and 7.1, line 16)

Pete Frochlich, Asst. AG, could not provide a satisfactory answer other than that it is a standard and non-controversial provision and that any extensions would have to be approved by legislature — so why get uptight?

My concern is that a contract with this provision in it is a lot easier to get extended and kept going (as ARCO certainly would wish — they want the royalty gas over the life of production) than if you had to renegotiate it. I may be all wet.

AGO 801413

about that and needlessly concerned!

— If the contract between the State and Phillips gets terminated or deliveries of royalty gas (to APC) are not effectuated, the State's election to take its royalty gas in-kind is revoked (14.4, lines 26-29)

Pete Froehlich assured me that we are not giving up our right to take in-kind at some future date.

— The Phillips contract with the State is not being submitted for legislative approval, although it is being submitted as an exhibit to the APC/State contract.

Pete F clarified that there was no statutory authority to require leg. appvl, and everything was up front by virtue of it being part of the APC/State contract.

AGO 801414

Exhibit "B"

AGREEMENT

This Contract, made and entered into this 11th day of April, 1977, by and between the State of Alaska, herein referred to as "State", and Phillips Petroleum Company, herein referred to as "Lessee",

W I T N E S S E T H

WHEREAS, Lessee is the holder of certain mineral leases from the State in the North Cook Inlet area of Alaska, said leases identified in Exhibit "A" to this Agreement; and

WHEREAS, the State has the right under the terms of said leases to receive in value or in kind a 1/8 (one-eighth) royalty share of natural gas produced from said leases; and

WHEREAS, the State desires to receive its in kind royalty share of natural gas at a point other than at Lessee's production platform; and

WHEREAS, Lessee operates a gas pipeline to gather natural gas from the said leases to the LNG facility at Kenai, Alaska (hereinafter referred to as Kenai LNG Plant), which Lessee operates; and

WHEREAS, Lessee is willing to deliver to the State its in kind royalty share of the natural gas from said leases at a point near the Kenai LNG Plant; and

WHEREAS, the State desires to receive its royalty share of the natural gas from said leases at such a point

and has agreed with Alaska Pipeline Company to sell such gas to Alaska Pipeline Company (herein referred to as "APC") for resale and use within the State of Alaska according to the terms of that certain Gas Purchase Contract attached hereto as Exhibit "B".

NOW, THEREFORE, premises considered, the State and Lessee hereby mutually agree as follows:

ARTICLE I

DEFINITIONS

The following terms when used in this Agreement shall have the following meanings:

1.1. The term ~~"day"~~ shall mean a period of twenty-four (24) consecutive hours beginning and ending at 7:00 o'clock A.M. The reference date for any day shall be the date of the beginning of such day.

1.2 The term "month" shall mean a period beginning at 7:00 o'clock A.M. on the first day of a calendar month and ending at 7:00 o'clock A.M. on the first day of the next succeeding calendar month.

1.3 The term "Mcf" shall mean one thousand (1,000) cubic feet of natural gas measured as hereinafter provided.

ARTICLE II

The State's Royalty Gas

2.1 Within 30 days after the execution and approval of this Agreement as required by the laws of the State of Alaska, the State shall notify the Lessee under the leases

set forth at Exhibit A, the State's election to take its royalty gas in kind. Said notice will provide that the Lessee shall commence the delivery of said royalty gas to the State (or to the State's designee) upon a receipt of notice from the State that all facilities necessary to receive and market said gas are ready; provided, however, in no event shall Lessee be required to commence the delivery of royalty gas to the State (or its designee) prior to six (6) months following Lessee's receipt of notice of the State's election to take its royalty gas in kind.

2.2 In order that the State give Lessee as much advance notice as possible of the date it will start receiving its royalty gas in kind, the State shall notify Lessee that all facilities necessary to receive and market said gas are ready, at least sixty (60) days prior to the date on which Lessee shall be required to commence delivery pursuant to this Agreement.

ARTICLE III

FACILITIES

3.1 Lessee is presently operating and maintaining a natural gas gathering system between the North Cook Inlet Field and the Kenai LNG Plant.

3.2 The State or its designee shall install, maintain and operate all pipeline, pressure regulators, and related facilities necessary to receive gas hereunder at the point of delivery hereinafter specified. Said point of delivery shall be at or near the existing pipeline tap being presently used to deliver gas from Lessee's pipeline to the

Tesoro refinery located in the general vicinity of the Kenai LNG Plant on the North Kenai Road.

3.3 The State or its designee shall install, operate and maintain all necessary equipment at the point of delivery and at the State's or its designee's measuring station(s) (hereinafter called the "point of measurement") to properly control, odorize, and measure the volumes of gas delivered hereunder.

3.4 Lessee hereby grants the State or its designee ingress and egress at the point of delivery without charge for all purposes necessary hereto, and the State and its designee hereby agree to assure Lessee ingress and egress at the point of measurement and between the point of delivery and the point of measurement without charge for all purposes necessary hereto.

ARTICLE IV

QUANTITY OF GAS

4.1 Subject to the availability of capacity in its facilities to handle volumes in excess of its own needs and to the extent of such availability, and upon proper written notice from the State under Article II hereof, Lessee shall gather the royalty gas in the North Cook Inlet Field and deliver same to the State at the point of delivery specified herein. The State is entitled to receive at the wellhead 1/8 (one-eighth) of the natural gas produced from the leases listed in Exhibit "A", and to the extent that Lessee gathers and delivers more or less than the amount of royalty gas to which the State is entitled,

that difference shall be carried in the over and short account described below or Lessee shall purchase same on the basis provided in Section 4.3 below.

It is recognized that it is impossible to deliver to the State or for the State or its designee to receive the exact amount of royalty gas produced from the leases listed in Exhibit "A". Lessee agrees that it will carry an over and short account with respect to the receipts of royalty gas and the delivery of same to the State, provided, however, that Lessee shall never be required to carry more than a total of 60,000 Mcf over or under delivery. In the event the takes by the State on a cumulative basis shall ever be more than 60,000 Mcf less than the amount of royalty gas available at the point of delivery, the State shall not be allowed to make up for any such underdelivery, and Lessee shall purchase the excess undelivered quantities of royalty gas over 60,000 Mcf from the State at the wellhead on the basis provided in section 4.3 below.

4.2 Subject to (i) the availability of royalty gas at the platform and (ii) to the State's or its designee's requirements, and (iii) the State's or its designee's ability to take such requirement, Lessee shall use its best reasonable efforts to deliver to the State or its designee at the delivery point specified herein on an annual basis not less than three (3) billion cubic feet of royalty gas; provided, however, that in using such best reasonable efforts, Lessee shall not be required to install or operate any pipeline, compression or other facilities which, when operating as a reasonably prudent operator, it would not otherwise install

approx 2 MMcf/day

and/or operate.

4.3 The parties recognize that the State contemplates selling such royalty gas to Alaska Pipeline Company and that such purchaser may be unable from time to time to take and deliver to its customers the full volumes of gas attributable to the State's royalty interest although it is committed to purchase that volume from the State. In such event, Lessee agrees to purchase from the State from time to time those volumes which APC is unable to take. For such volumes which it purchases from the State, Lessee will pay the State a price equal to that amount which Lessee would have otherwise paid to the State as royalty if the State had not elected to receive its royalty gas in kind, and Lessee will not charge the State for gathering or compressing such volumes of gas or for other charges under this Agreement.

ARTICLE V

POINT OF DELIVERY AND OWNERSHIP

5.1 The point of delivery to the State for all gas gathered and delivered hereunder by Lessee shall be at the juncture of APC's facilities and Lessee's facilities located near the pipeline tap serving the Tesoro refinery as mentioned in Section 3.2 of this Agreement.

5.2 Lessee shall be deemed to be in control and possession of the gas deliverable hereunder and responsible for any damage or injury caused thereby until said gas shall have been delivered to the State or its designee at the point of delivery, after which delivery State or its designee shall be deemed to be in exclusive control and possession of

the gas and responsible for any injury or damage caused thereby.

5.3 Measurement of royalty gas shall be the responsibility of the State or its designee subject to Lessee's right to verify such measurement or to install and operate check metering equipment, and shall be done at a metering station(s) on the North Kenai Road, called the "point of measurement". The State or its designee shall be responsible for any gas lost between the point of delivery and the point of measurement.

ARTICLE VI

QUALITY, PRESSURE, AND ODORIZATION

6.1 Lessee shall deliver gas hereunder at the pressure existing from time to time in its facilities at the point of delivery.

6.2 Lessee agrees that the quality of gas, when delivered at the point of delivery hereunder, shall be the quality of gas existing in its gathering system from time to time and the State agrees to accept such gas.

6.3 It is understood that the gas delivered hereunder will not be odorized by Lessee, and if the State or its purchaser so utilizes the gas delivered hereunder for purposes which require odorization of such gas, the full responsibility for such use is the State's. Lessee shall have no responsibility for odorizing such gas irrespective of the State's disposition of same.

ARTICLE VII

STANDARDS OF MEASUREMENT AND TESTS

7.1 Except for the determination and computation

of total heating value, the unit of volume of gas delivered hereunder shall be one (1) cubic foot at an absolute pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch and at a base temperature of sixty (60) degrees Fahrenheit.

7.2 The volumes of gas delivered hereunder shall be measured and computed by the State or its designee in accordance with the methods prescribed in Gas Measurement Committee Report No. 3, Natural Gas Department, American Gas Association, including the Appendix thereto, dated April, 1965, except that the atmospheric pressure shall be assumed to fourteen and seven-tenths (14.7) pounds per square inch. The method used for correcting such volumes for deviation from the Ideal Gas Laws shall be the procedure recommended in the most current Report of the American Gas Association or by any other method mutually agreeable to the parties hereto.

7.3 The specific gravity of the gas delivered hereunder shall be determined by Lessee's utilizing the method prescribed in American Petroleum Institute Code No. 50-A at the beginning of delivery hereunder and once during each month thereafter. The results of each such determination shall be used in computing the volume of gas delivered hereunder until the effective date of the next succeeding test.

7.4 The flowing temperature of the gas delivered hereunder shall be determined by means of a continuous recording thermometer installed by the State or its designee so that it will properly record the temperature of the gas flowing through the meter. The arithmetical average of the

hourly temperatures recorded each day shall be used in computing the volumes of gas delivered during such day.

7.5 If the gas delivered hereunder is solely from the 16-inch pipeline serving the North Cook Inlet Field, the total heating value of the gas shall be the average of that recorded on the recording calorimeter for Lessee's gas at the inlet to Kenai LNG Plant during the billing period corrected to thirty (30) inches of Mercury and sixty (60) degrees Fahrenheit dry.

ARTICLE VIII

MEASUREMENT

8.1 As agreed in Section 5.3 hereof, the State or its designee shall be obligated to and be responsible for all metering of gas hereunder.

8.2 The State or Lessee may, at their option and expense, install check meters upstream or downstream of the State's or its designee's meter station provided that such check meters will be installed so as not to interfere with the operation of the State's or its designee's facilities. The calibrating and adjusting of meters and the changing of charts and the reading of charts on meters shall be done by the party who installed the meters.

8.3 The State and Lessee shall have access at all times to the State's or its designee's metering equipment including all other instruments used by the State or its designee in determining the measurement and quality of the gas delivered hereunder, but the reading, calibrating and adjusting thereof, and the changing of charts shall be done

only by the employees, agents, or representatives of the State or its designee. Upon request of Lessee, the State or its designee shall submit to Lessee records and charts from such equipment subject to return by Lessee within thirty (30) days after receipt thereof.

8.4 At least once a month the State or its designee shall test its above-mentioned metering equipment or cause the same to be tested and shall give Lessee or its representative reasonable prior notice of the time all such tests are to be made so that Lessee may, if desired, have its representative present to observe such tests and any adjustments made upon such metering equipment. Following any test, any of the State's or its designee's metering equipment found to be inaccurate to any degree shall be adjusted immediately to measure accurately. If upon any test such metering equipment is found to be inaccurate by two percent (2%) or more, registration from said metering equipment and any payments based upon such registrations shall be corrected at the rate of such inaccuracy for any period of inaccuracy which is definitely known or agreed upon, but in case the period is not definitely known or agreed upon, then for a period extending back one-half (1/2) of the time elapsed since the last previous test, not exceeding, however, fifteen (15) days.

8.5 If for any reason the State's or its designee's meter is out of service or is found registering inaccurately and the error is not determinable by ordinary test such that the volume of gas delivered through such meter cannot be ascertained or computed from the readings thereof, the

volume of gas so delivered during the period the meter is out of service or registering inaccurately shall be estimated and agreed upon by the parties hereto upon the basis of the best available data, using the first of the following methods which is feasible:

(a) by correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation;

(b) By using the registration of any check measuring equipment of Lessee if installed and registering accurately;

(c) By estimating the volume by comparing it with deliveries during preceding periods under similar conditions when the meter was registering accurately.

ARTICLE IX

GATHERING AND COMPRESSION CHARGES AND TAXES

9.1 For all gas delivered by Lessee to the State at the delivery point, the State or its designee shall pay to Lessee a gathering charge of ten cents (10.0¢) per Mcf from the date of first delivery hereunder. The above-stated charge shall increase by six percent (6%) per year, compounded annually, on each anniversary date of the date this Agreement.

9.2 It is recognized by the parties hereto that it may be necessary for Lessee to install compression facilities during the term of this Agreement. At the time the first compressor unit is installed and first used, the State

or its designee shall pay Lessee in addition to the gathering charge set forth in Section 9.1, a compression charge of ten cents (10.0¢) per Mcf for all gas delivered by Lessee to the State at the delivery point. Such charge shall increase by six percent (6%) per year, compounded annually, commencing on the first anniversary of the date such compression facilities are installed and first used.

9.3 In the event that Lessee installs or causes to be installed from time to time compression facilities in addition to the first compressor unit mentioned in Section 2, above, Lessee shall give the State and its designee written notice at least six (6) months prior to the time Lessee anticipates placing any additional unit or units in operation in order to maintain capacity in its gathering system. Such notice shall also terminate this Agreement at the end of such six (6) months period. If, within ninety (90) days of the date of such notice the parties shall agree upon a new compression charge to be applicable when such additional compression facilities go into operation, then this Agreement shall not terminate but shall continue in full force and effect as amended to include the new compression charge.

9.4 Lessee shall pay all ad valorem taxes on its pipelines and facilities employed in delivering gas hereunder. In addition to the price and payments hereinabove provided, the State shall reimburse Lessee in the proportion of deliveries made to the State by Lessee, an amount equal to the aggregate total of any new or increased fee, impost, duty, charge, excise or tax levied or imposed in addition to the rates at which those, if any, are levied, assessed, or

fixed as of the date hereof, with respect to the gathering of the royalty gas delivered hereunder (including compression) prior to its delivery to the State that Lessee may be required to pay for directly or indirectly.

ARTICLE X

BILLING AND PAYMENTS

10.1 On or before the 15th day of each month during the term hereof the State or its designee shall furnish Lessee with a full and complete statement reflecting all gas delivered by Lessee during the preceding month and the total amount due hereunder pursuant to Article IX hereof. Payment hereunder shall be made to Lessee at its office in Bartlesville, Oklahoma within ten (10) days after delivery of each such statement.

10.2 On or before the 30th day of each month during the term hereof Lessee shall furnish to the State or its designee a full and complete statement reflecting the total amount of royalty gas produced by Lessee during the preceding month. Deducting the quantity taken by the State for such month, Lessee shall determine the amount of royalty gas not taken by the State for such month and shall make payment therefor to the State together with said statement.

10.3 Each party hereto shall have, at its expense, the right to examine the books and records of the other party to the extent necessary to verify the accuracy of any statement or invoice made under or pursuant to this contract. Any statement shall be final as to both parties unless questioned in writing within two (2) years after payment

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thereof has been made.

ARTICLE XI

REPRESENTATION AND CONDITION PRECEDENT

11.1 It is expressly recognized and agreed that the gas gathering system utilized for deliveries hereunder is operated and maintained by Lessee for its own purpose and Lessee does not, by entering into this Agreement, dedicate any facilities or otherwise undertake to render any service to or for the public. This Agreement is being undertaken solely to effectuate the delivery of royalty gas to the State, and the State makes the material representation that neither this Agreement nor the State's use or disposition of the gas delivered hereunder will subject Lessee to regulation by the Federal Power Commission, the Alaska Public Utilities Commission, or the Alaska Pipeline Commission.

11.2 In the event that any governmental agency shall declare that Lessee's activities hereunder subject Lessee to regulation as a utility, then either party shall have the option to terminate this Agreement upon thirty (30) days' notice in writing.

ARTICLE XII

ALASKA PIPELINE COMPANY

12.1 The State has entered into a Gas Purchase Agreement with Alaska Pipeline Company, under the terms of which APC will purchase the State's royalty gas after same has been delivered by Lessee to the State. Under such contract, APC has agreed to make for the State's account all

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payments required by Articles IX and X hereof. Lessee agrees to accept such payments by APC as satisfaction of the State's obligations under Articles IX and X hereof. In the event of default by APC in making such payments, Lessee shall promptly notify the State and if such default continues for a period of thirty (30) days after such notice, Lessee shall have the option of terminating this Agreement in its entirety.

12.2 Lessee agrees to accept the State's designation of APC as the State's designee hereunder for the performance of any other obligations which the provisions hereof place on the State.

12.3 By its execution hereof APC ratifies all of the terms, covenants, conditions, and representations hereof.

ARTICLE XIII

FORCE MAJEURE

13.1 No liability shall result to either party from delay in performance or non-performance of any obligation hereunder (except the State's obligation to make payment hereunder) caused by circumstances reasonably beyond the control of the party affected, including, but not limited to, acts of God, fire, flood, storm, war (declared or undeclared), repair of facilities, breakage or accident to machinery or lines of pipe, repair, redrilling or reworking of wells, governmental regulation, requisition or direction, or labor strikes or lockouts.

13.2 The party claiming relief under this Article XIII shall advise the other party with reasonable promptness

in writing giving full particulars of the cause or causes relied upon and shall also give prompt notice in writing of the cessation of any such cause or causes. The party claiming force majeure shall exercise due diligence in undertaking to remedy and overcome the cause of delay hereunder, but neither party shall be required to agree to any demand of labor to settle any strike or labor dispute except in the sole discretion of the party subject to such strike or labor dispute.

ARTICLE XIV

TERM

14.1 This Agreement shall become effective upon the execution hereof and the execution and approval of the Alaska Royalty Oil and Gas Development Advisory Board and the State Legislature of the Contract attached as Exhibit "B" hereto and shall remain in effect until June 1, 1984, unless terminated or extended prior to such date by mutual agreement of the parties, or pursuant to this Article or Article XI or XIII.

14.2 In the event that the Agreement attached hereto as Exhibit "B" is terminated, this Agreement may be terminated by either party upon thirty (30) days notice.

14.3 If deliveries to the State or its designee hereunder have not commenced on or before June 30, 1978, then this Agreement shall terminate immediately.

14.4 In the event of termination of this Agreement or of deliveries of royalty gas hereunder, the parties agree that such termination shall have the effect of revoking the State's election to receive its royalty gas in-kind

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as of the date of termination and Lessee shall immediately commence such royalty payment under the terms of the leases listed in Exhibit "A" to assure the state of its full royalty share on all gas produced from the leases.

ARTICLE XV

MISCELLANEOUS

15.1 Except as herein otherwise provided, any notice, request, demand, statement or bill provided for in this Agreement, or any notice which either party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered mail to either of the parties hereto as the case may be at the following address:

Commissioner of Natural Resources
State of Alaska
Pouch M
Juneau, Alaska 99811

Phillips Petroleum Company
Attn: Gas and Gas Liquids Division
Bartlesville, Oklahoma 74004

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

or at such other address as either party shall designate from time to time by formal written notice. Routine communications, including monthly statements and payments, shall be considered as duly delivered when mailed by either registered or ordinary mail.

IN WITNESS WHEREOF, this Agreement is executed as of the day and year first above written.

STATE OF ALASKA

By _____

~~ATTEST~~:

_____
~~Assistant Secretary~~

PHILLIPS PETROLEUM COMPANY

By _____
~~Vice President~~
ATTORNEY IN FACT

ATTEST:

_____
Assistant Secretary

ALASKA PIPELINE COMPANY

By _____
President

EXHIBIT "A"

Attached to and Made a Part of a Gas Purchase and Sales Agreement dated April 11, 1977, Between PHILLIPS PETROLEUM COMPANY "~~Buyer~~" and the STATE OF ALASKA "~~Seller~~", With Respect to Certain Royalty Gas Owned and Taken in Kind by the STATE Under the Leases Described Herein Covering Lands in the State of Alaska.

Each of the Following described Leases reserves to the State of Alaska a one-eighth royalty interest.

Lease Serial No.	Legal Description	Gross Acres
		5,002.
ADL-17589 2/1/62	T.12N., R.9W., S.M. Sec. 31: All; Sec. 32: All. T.11N., R.9W., S.M. Sec. 5: All; Sec. 6: All; Sec. 7: All; Sec. 18: N 1/2. T.11N., R.10W., S.M. Sec. 12: All; Sec. 13: N 1/2.	4,375.50
		5,120.
ADL-17590 3/1/62	T.12N., R.9W., S.M. Sec. 21: W 1/2; Sec. 28: W 1/2.	640.00
		5,120
ADL-18740 9/1/62	T.12N., R.10W., S.M. Sec. 35: SE 1/4. T.11N., R.10W., S.M. Sec. 2: E 1/2; Sec. 11: E 1/2.	800.00
		5,120.
ADL-18741 9/1/62	T11N., R.9W., S.M. Sec. 9: N 1/2, SW 1/4. T.12N., R.9W., S.M. Sec. 33: NW 1/4.	640.00

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5,051.

ADL-37831
9/1/62

T.12N., R.9W., S.M.	3,326.00
Sec. 29: All;	
Sec. 30: All;	
Sec. 19: SE 1/4;	
Sec. 20: NE 1/4, S 1/2.	
T.12N., R.10W., S.M.	
Sec. 36: All;	
Sec. 25: SE 1/4.	
T.11N., R.10W., S.M.	
Sec. 1: All.	

Exhibit "A"

EXHIBIT "B"

GAS PURCHASE CONTRACT

This Contract, made and entered into this 11th day of April 1977, by and between the Alaska Pipeline Company ("APC") herein referred to as "Buyer" and the State of Alaska, hereinafter referred to as "Seller":

WITNESSETH

WHEREAS, Buyer owns and operates a natural gas pipeline system in areas of Alaska for the delivery of natural gas for ultimate consumption within the State of Alaska, and

WHEREAS, Seller has the right under each of the leases, identified in Exhibit "A" to this Contract, to be paid by Lessee thereunder a royalty of twelve and one-half percent in-kind or in-value of the natural gas produced and saved or used off of the lands covered by each lease, and

WHEREAS, Seller is authorized by AS 38.05.183 to sell royalty gas; and

WHEREAS, Buyer represents to Seller that the gas received by Buyer under this contract will be used to meet the requirements of its customers within the State of Alaska; and

WHEREAS, this Gas Purchase Contract when executed will supersede and extinguish that certain Gas Purchase Contract executed June 4, 1976 by the parties hereto;

NOW, THEREFORE, in consideration of the representations, covenants, and conditions herein contained, Buyer and Seller hereby agree as follows:

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ARTICLE I

DEFINITIONS

Seller's Royalty Gas

2.1 Seller hereby agrees that within 30 days after the execution and approval of this agreement as required by the laws of the State of Alaska, Seller shall notify the Lessee under the leases set forth at Exhibit "A" of Seller's election to take its royalty gas in-kind. Said notice will provide that the Lessee shall commence the delivery of said royalty gas to Seller or to Seller's designee upon a receipt of notice from Seller that all facilities necessary to enable Buyer to receive and market said gas are ready; provided, however, in no event shall Lessee be required to commence the delivery of royalty gas to Seller or its designee prior to six (6) months following Lessee's receipt of notice of Seller's election to take its royalty gas in-kind.

2.2 In order that Seller can give its Lessee as much advance notice as possible of the date it will start receiving its royalty gas in-kind, Buyer shall notify Seller, and Seller shall notify its Lessee, that all facilities necessary to receive and market said gas are ready, at least 60 days prior to the date Buyer will receive gas from Seller pursuant to this Contract.

2.3 Buyer agrees that Seller's royalty gas which is purchased and received by Buyer will be used or resold for use

within the State of Alaska.

ARTICLE III

Quantity

3.1 It is understood and agreed by the parties that the volume of gas available to Seller from the leases covered by this Contract depends upon the production from the leases over which Seller has no control, and further depends upon the Lessee's gathering capacity installed and available, over which Seller likewise has no control. Buyer hereby agrees to purchase on each day commencing with the date of first delivery hereunder and continuing during the term of this contract up to all of Seller's royalty gas available at the point of delivery described in Section 5.1 hereof, it being understood that Buyer's requirements for its markets may not allow Buyer to purchase the entire amount of Seller's royalty gas on each day it is available; and it being further understood that Buyer will take not less than the amount for which Buyer has demand and delivery facilities available. Buyer shall use its best reasonable efforts to take not less than three (3) billion cubic feet per year of royalty gas at the point of delivery.

3.2 It is recognized that it is impossible to deliver to Buyer each day the exact amount of royalty gas produced from the leases listed in Exhibit "A". Seller agrees that Seller or Lessee will carry an over and short account with respect to the receipts of royalty gas and the delivery of same to Buyer; provided,

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however, that the account shall never be required to carry more than a total of 60,000 Mcf over or underdelivery. In the event the takes by Buyer on a cumulative basis shall ever be more than 60,000 Mcf less than the amount of royalty gas available to Buyer at the point of delivery, Buyer shall not be allowed to make up for any such underdelivery and Seller may sell the undelivered quantity of royalty gas to Lessee.

ARTICLE IV

Quality, Pressure, and Odorization

4.1 The gas to be delivered by Seller to Buyer at the delivery point shall be gas of the same quality and pressure as delivered to Seller by the Lessee at the point of delivery. Seller shall have no obligation to improve the quality or pressure of gas beyond that quality and pressure at which Lessee delivers the gas to seller.

4.2 Gas delivered hereunder will not be odorized and if Buyer so utilizes the gas delivered hereunder for purposes which require odorization of such gas, the full responsibility for such use is Buyer's and Buyer agrees to comply with all laws and regulations respecting the odorization of such gas and hereby indemnifies and holds Seller harmless from any and all claims, injuries, expenses, penalties and damages arising out of or connected with Buyer's failure to observe strictly and comply with all laws, rules and regulations with respect hereto.

ARTICLE V

Point of Delivery, Point of Measurement, Ownership, and Measurement

5.1 Buyer shall install, maintain, and operate a connection into the Lessee's pipeline system at or near Lessee's pipeline tap presently being used to deliver gas from Lessee's pipeline to the Tesoro refinery located in the general vicinity of the Kenai LNG plant on the North Kenai Road, (hereinafter called "the point of delivery"). The point of delivery of all gas delivered hereunder shall be at the same point of delivery that Seller receives its royalty gas from the Lessee.

5.2 Buyer agrees to install, maintain, and operate all pipeline, pressure regulators, and related facilities necessary to receive gas hereunder at and from the point of delivery above specified, to Buyer's metering station(s) also located in the general vicinity of the Kenai LNG plant on the North Kenai Road (hereinafter called "the point of measurement").

5.3 Buyer shall be deemed to be in control and possession of the gas delivered hereunder at and from the point of delivery and responsible for any damage or injury caused thereby. Buyer shall be responsible for any gas lost between the point of delivery and the point of measurement. Buyer shall indemnify and hold Seller harmless as to any injury or damage arising out of the delivery of gas to Buyer and its measurement hereunder.

5.4 Standards of Measurements and Tests

5.4.1 Except for the determination and computation of total heating value, the unit of volume of gas delivered hereunder shall be one (1) cubic foot at an absolute pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch and at a base temperature of sixty (60) degrees Fahrenheit.

5.4.2 The volumes of gas delivered hereunder shall be measured and computed by Buyer in accordance with the methods prescribed in Gas Measurement Committee Report No. 3, Natural Gas Department, American Gas Association, including the Appendix thereto, dated April, 1955, except that the atmospheric pressure shall be assumed to be fourteen and seven-tenths (14.7) pounds per square inch. The method used for correcting such volumes for deviation from the Ideal Gas Laws shall be the procedure recommended in the most current Report of the American Gas Association or by any other method mutually agreeable to the parties hereto.

5.4.3 The specific gravity of the gas delivered hereunder shall be determined by Lessee utilizing the method prescribed in American Petroleum Institute Code No. 50-A at the beginning of delivery hereunder and once during each month thereafter. The results of each such determination shall be used in computing the volume of gas delivered hereunder until the effective date of the next succeeding test.

5.4.4 The flowing temperature of the gas delivered hereunder shall be determined by means of a continuous recording thermometer installed by Buyer so that it will properly record

the temperature of the gas flowing through the meter. The arithmetical average of the hourly temperatures recorded each day shall be used in computing the volumes of gas delivered during such day.

5.4.5 If the gas delivered hereunder is solely from the 16-inch pipeline serving the North Cook Inlet Field, the total heating value of the gas shall be the average of that recorded on the recording calorimeter for Lessee's gas at the inlet to Kenai LNG Plant during the billing period corrected to thirty (30) inches of Mercury and sixty (60) degrees Fahrenheit dry.

5.5 Measurement

5.5.1 Seller or Lessee may at their option and expense, install check meters upstream or downstream of Buyer's meter station provided that such check meters will be installed so as not to interfere with the operation of Buyer's facilities. The calibrating and adjusting of meters and the changing of charts and the reading of charts on meters shall be done by the party who installed the meters.

2 Why? It's their equipment!

5.5.2 Buyer, Lessee, and Seller shall have access at all times to Buyer's metering equipment including all other instruments used by Buyer in determining the measurement and quality of the gas delivered hereunder, but the reading, calibrating and adjusting thereof, and the changing of charts shall be done only by the employees, agents, or representatives of Buyer. Upon

request of Lessee or Seller, Buyer shall submit to Lessee or Seller records and charts from such equipment subject to return by Lessee or Seller within thirty (30) days after receipt thereof. Buyer hereby agrees to assure Seller and Lessee ingress and egress at the point of measurement and between the point of delivery and the point of measurement without charge for all purposes necessary hereto.

5.5.3 At least once a month Buyer shall test its above mentioned metering equipment or cause the same to be tested and shall give Lessee or the representative reasonable prior notice of the time all such tests are to be made so that Lessee may, if desired, have its representative present to observe such tests and any adjustments made upon such metering equipment. Following any test, any of Buyer's metering equipment found to be inaccurate to any degree shall be adjusted immediately to measure accurately. If upon any test such metering equipment is found to be inaccurate by two percent (2%) or more, registration from said metering equipment and any payments based upon such registrations shall be corrected at the rate of such inaccuracy for any period of inaccuracy which is definitely known or agreed upon, but in case the period is not definitely known or agreed upon, then for a period extending back one-half of the time elapsed since the last previous test, not exceeding however, fifteen (15) days.

5.5.4 If for any reason Buyer's meter is out of service or is found registering inaccurately and the error is not determinable by ordinary test such that the volume of gas delivered

through such meter cannot be ascertained or computed from the readings thereof, the volume of gas so delivered during the period the meter is out of service or registering inaccurately shall be estimated and agreed upon by the parties hereto upon the basis of the best available data, using the first of the following methods which is feasible:

(a) By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation;

(b) By using the registration of any check measuring equipment of Lessee if installed and registering accurately;

(c) By estimating the volume by comparing it with deliveries during preceding periods under similar conditions when the meter was registering accurately.

ARTICLE VI

Price and Billing

6.1 The price to be paid by Buyer to Seller for gas deliveries shall be as follows:

(a) Commencing on the date of first deliveries hereunder assuming that this date occurs prior to July 1, 1978 and continuing until the first day of July, 1978, the price shall be 64.65 cents per MCF.

(b) Commencing on the first day of July, 1978 and continuing until the first day of July, 1979 the price shall be the higher of (i) 66.65 cents per

MCF, (ii) the price Seller would have received from Lessee had it not elected to receive its royalty gas in kind, (iii) the highest price paid by any purchaser in the upper Cook Inlet area for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges.

What does that include? Previously 100 km radius!

(c) For each succeeding 12 month period commencing July 1, 1979 the price shall be increased to the higher of (i) the previous year's price plus 2 cents per Mcf, (ii) the price Seller would have received had it not elected to take its royalty in-kind, (iii) the highest price paid by any purchaser in the upper Cook Inlet area for gas of similar quality and conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of contract and connection charges.

(d) In addition to the price otherwise payable hereinabove, for gas delivered to Buyer at the delivery point Buyer shall pay to Lessee, for the account of Seller, a gathering charge of ten cents (10.0¢) per Mcf from the date of first delivery hereunder. The above stated charge shall increase six percent (6%) compounded annually on each anniversary of the date of this contract.

(e) It is recognized by the parties hereto that it will be necessary for Lessee to install compression facilities

during the term of this Agreement. At the time the first compressor unit is installed and first used, Buyer shall pay to Lessee, for the account of Seller, in addition to the price and gathering charge otherwise payable hereinabove, a compression charge of ten cents (10.0¢) per Mcf for all gas delivered to Buyer at the delivery point. Such charge shall increase by six percent (6%) per year compounded annually, commencing on the first anniversary of the date such compression facilities are installed and ready for operation. Nothing herein shall be construed by either party as an obligation on Lessee to install any compression facilities whatever or to operate any compression facilities already installed.

(f) In addition to the price provisions stated herein, Buyer hereby agrees to pay Seller as part of the total purchase price of the royalty gas any costs not otherwise stated herein incurred by Seller in transporting that gas to the point of delivery specified in section 4.1 of this agreement including but not limited to any amount which Seller is obligated to reimburse Lessee for a proportion of new or increased fees, imposts, duties, charges or taxes.

6.2 Thirty days prior to the date of each annual price change, Seller, at its option, may determine the price which it would have received from its Lessee had it not elected to take its royalty

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gas in-kind and the highest price being paid for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges in the upper Cook Inlet area and submit the same to Buyer along with suitable supporting evidence as to such prices. Buyer shall have the right to submit other evidence within the 30 day period.

6.3 On or before the 15th day of each month after the delivery of gas hereunder has commenced Buyer shall furnish Seller and Lessee with a full and complete statement reflecting the quantity of gas delivered at the delivery point during the preceding month and the total amounts due hereunder. Payment under sections 6.1(d), 6.1(e) and 6.1(f) of this Contract shall be made to Lessee on account of Seller at Lessee's office in Bartlesville, Oklahoma within ten (10) days after delivery of each such statement. Payment under sections 6.1(a), 6.1(b) and 6.1(c) of this Contract shall be made to Seller on the day of delivery of each such statement by direct wire transfer of federal reserve funds through the Federal Reserve Bank wire transfer system to the following address:

BANK OF AMERICA, NA + SA
San Francisco, California
Securities Department 3255
Credit to: State of Alaska Investment Account

or to such other address as the Commissioner of Revenue may designate.

6.4 Each party hereto shall have, at its expense, the right to examine the books and records of the other party to the extent

necessary to verify the accuracy of any statement, charge, computation, or demand made under or pursuant to this contract. Any statement shall be final as to both parties unless questioned in writing within two (2) years after payment thereof has been made.

6.5 The terms "upper Cook Inlet area" as used herein shall mean the area encompassed in a radius of 100 kilometers from the Lessee's North Cook Inlet platform.

ARTICLE VII

Termination

7.1 This contract shall become effective upon the execution hereof and the approval of the Alaska Royalty Oil and Gas Development Advisory Board and the State Legislature and shall continue and remain in effect until June 1, 1984 unless terminated or extended prior to such date by mutual agreement of the parties, or pursuant to this Article or Article VIII.

7.2 Seller's obligations hereunder are contingent upon Seller arranging with Lessee for satisfactory transportation of royalty gas sold hereunder to the point of delivery specified in section 4.1 of this agreement. If, after exercising Seller's best efforts, Seller is unable to arrange such transportation on terms satisfactory to Seller, Seller shall give notice to Buyer and this agreement shall terminate 30 days after said notice.

7.3 The parties hereby agree that in the event that any governmental agency declares that Lessee's activities hereunder subject Lessee to regulation as a utility, then either party shall have the option to give notice to the other and this agreement shall terminate 30 days after said notice.

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7.4 In the event of default by Buyer in making the payments required by this Contract, Seller shall give notice to Buyer and if the default continues for a period of 30 days after such notice, Seller shall have the option of terminating this Contract.

7.5 In the event that Lessee installs or causes to be installed compression facilities in addition to the first compressor unit mentioned in section 6.1(e) of this contract, Seller shall give Buyer written notice at least six (6) months prior to the time Lessee anticipates placing such additional facilities in operation to maintain capacity in its gathering system. Such notice shall also terminate this agreement at the end of the six (6) month period unless within ninety (90) days of the date of such notice a new compression charge is agreed upon by the two parties to be applicable when the additional facilities go into operation. If a new compression charge is agreed upon, this agreement shall not terminate but shall continue in full force and effect as amended to include the new compression charge.

Whose they?
State/Phillips
State/APC
APC/Phillips

7.6 If the agreement between Seller and Lessee attached hereto as Exhibit "B" is terminated for any reason, this agreement may be terminated by either party upon thirty (30) days notice.

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7.7 If deliveries to Buyer hereunder have not commenced on or before June 30, 1978, then this Contract shall immediately terminate.

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ARTICLE VIII

Representation, Condition Precedent and Force Majeure

8.1 It is expressly recognized and agreed that the gas gathering system utilized for deliveries hereunder is operated and maintained by Lessee for its own purpose and that Lessee will not dedicate any facilities or otherwise undertake to render any service to or for the public. This Agreement is being undertaken solely to effectuate the delivery of royalty gas which Buyer is purchasing from the State of Alaska, and the parties hereto make the material representation that neither this Agreement nor Buyer's use or disposition of the gas delivered hereunder will subject Lessee to regulation by the Federal Power Commission or the Alaska Public Utilities Commission or the Alaska Pipeline Commission.

8.2 Force Majeure

8.2.1 No liability shall result to either party from delay in performance or non-performance of any obligation hereunder (except Buyer's obligation to make payment hereunder) caused by circumstances reasonably beyond the control of the party affected, including, but not limited to, acts of God, fire, flood, storm, war (declared or undeclared), repair of facilities, breakage or accident to machinery or lines of pipe, repair, redrilling or reworking of wells, governmental regulation, requisition or direction, labor strikes or lockouts or breach of contract by Lessee.

8.2.2 The party claiming relief under this Article VIII shall advise the other party with reasonable promptness in writing

giving full particulars of the cause or causes relied upon and shall also give prompt notice in writing of the cessation of any such cause or causes. The party claiming force majeure shall exercise due diligence in undertaking to remedy and overcome the cause of delay hereunder, but neither party shall be required to agree to any demand of labor to settle any strike or labor dispute except in the sole discretion of the party subject to such strike or labor dispute.

Who are they? State/APC/~~Phillips~~

ARTICLE IX

Miscellaneous

9.1 The terms and provisions of this Agreement shall extend to and be binding upon the parties hereto, their assigns and successors in interest. It is understood, however, that Buyer may not assign its rights and interest in this Agreement without the written consent of Seller, except as may be necessary to Buyer to conform with its various financing documents or as may be desirable to Buyer as to its commonly owned affiliate or subsidiary. No assignment shall relieve any assignor of this Agreement of its obligations hereunder without the written consent of Seller.

Who or what does that mean?

9.2 In the event Buyer does not receive or purchase all of said royalty gas which is available to Buyer, then Seller may receive and dispose of that portion not taken by Buyer provided Seller does not burden Buyer with any cost therefor including Lessee's charges for gathering and compression on the gas not taken by Buyer.

Who all is covered under that?

Why is this all nec. since Phillips would take excess gas in value 4.3

Who would pay these charges if Phillips assesses them

?

AGO 801450

ARTICLE X

Notices

10.1 Except as herein otherwise provided, any notice, request, demand, statement or bill provided for in this Contract, or any notice which either party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered mail to either of the parties hereto as the case may be at the following address:

Commissioner of Natural Resources
State of Alaska
Pouch M
Juneau, Alaska 99811

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

or at such other address as either party shall designate from time to time by formal written notice. Routine communications, including monthly statements and payments, shall be considered as duly delivered when mailed by either registered or ordinary mail except payments for royalty gas from Buyer to Seller which must be made by wire transfer under section 6.3 of this Contract.

IN WITNESS WHEREOF, the parties hereto have caused this Contract to be executed in two (2) original counterparts on this day and year first above written.

BUYER

_____

ATTEST:

_____

STATE OF ALASKA

_____

ATTEST:

_____

ARCOGOAB Contract 76-1

Gas Purchase Contract

This Contract, made and entered into this 4th day of June 1976, by and between the Alaska Pipeline Company ("APC") herein referred to as "Buyer" and the State of Alaska, hereinafter referred to as "Seller" :

WITNESSED

WHEREAS, Buyer owns and operates a natural gas pipeline system in areas of Alaska for the delivery of natural gas for ultimate consumption within the State of Alaska, and

WHEREAS, Seller has the right under each of the leases identified at Exhibit "A" attached hereto to be paid by the lessee thereunder a royalty of twelve and one-half percent in kind or in value of the natural gas produced and saved and used off of the lands covered by each such lease, and

WHEREAS, Seller is authorized by AS 38.05.183 to sell royalty gas; and

WHEREAS, Buyer represents to Seller that all gas purchased under this contract will be used to meet the requirements of its customers within the State of Alaska;

NOW, THEREFORE, in consideration of the representations, covenants, and conditions herein contained, Buyer and Seller hereby agree as follows:

ARTICLE 1

Seller's Royalty Gas

1.1 Seller hereby agrees that within 30 days after the execution and approval of this agreement as required by the laws of the State of Alaska, Seller shall notify the lessee under the leases set forth at Exhibit "A" of this agreement of Seller's election to take its royalty gas in kind. Said notice will provide that the lessee shall commence the delivery of said royalty gas to Seller (or to Seller's designee) upon a receipt of notice from Seller that all facilities necessary to enable Buyer to receive and market said gas are ready; provided, however, in no event shall lessee be required to commence the delivery of royalty gas to Seller (or its designee) prior to six (6) months following lessee's receipt of notice of Seller's election to take its royalty gas in kind.

1.2 In order that Seller can give its lessee as much advance notice as possible of the date it will start receiving its royalty gas in kind, Buyer shall notify Seller, and Seller shall notify its lessee, at least 60 days prior to the date Buyer will receive gas from Seller pursuant to this contract.

ARTICLE II

Quantity

2.1 It is understood and agreed by the parties that the volume of gas available to Seller from the leases covered by this contract depends upon the production from the leases over which Seller has no control. Buyer hereby agrees to purchase on each day commencing with the date of first delivery

hereunder and continuing during the term of this contract all of Seller's royalty gas available at the point of delivery described in Article III hereof.

ARTICLE III

Delivery Point and Delivery Pressure

3.1 The point of delivery of all gas delivered hereunder shall be at the same point of delivery that Seller receives delivery of its royalty gas from its lessee in the North Cook Inlet Field.

3.2 Buyer, at its own expense, shall arrange to accept Seller's gas at the point of delivery.

3.3 Seller will deliver gas received by Seller from lessee at the pressure at which the gas is received by Seller from its lessee.

ARTICLE IV

Quality

4.1 The gas to be delivered by Seller to Buyer at the delivery point shall be gas of the same quality as is delivered to Seller by the lessee at the point of delivery.

AGO 801454

ARTICLE V

Price and Billing

5.1 The price to be paid by Buyer to Seller for gas delivered shall be as follows:

a. Commencing on the date of first deliveries hereunder, assuming that this date occurs prior to July 1, 1977 and continuing until the first day of July 1977, the price shall be 55.5 cents per MCF.

b. Commencing on the first day of July 1977 and continuing until the first day of July 1978 the price shall be the higher of (i) 60.36 cents per MCF, (ii) the price Seller would have received from Phillips Petroleum Company had it not elected to receive its royalty gas in kind, (iii) the highest price paid by any purchaser in the upper Cook Inlet area for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges.

c. For each succeeding 12 month period commencing July 1, 1978 the price shall be increased to the higher of (i) the previous year's price plus 2 cents per MCF, (ii) the price Seller would have received had it not elected to take its

royalty in kind, (iii) the highest price paid by any purchaser in the upper Cook Inlet area for gas of similar quality and conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges.

5.2 Thirty days prior to the date of each annual price change, Seller, at its option, may determine the price which it would have received from its lessee had it not elected to take its royalty gas in kind and the highest price being paid for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges in the upper Cook Inlet area and submit the same to Buyer along with suitable supporting evidence as to such prices. Buyer shall have the right to submit other evidence within the 30 day period.

5.3 After the delivery of gas has commenced Buyer shall, on or before the 20th day following the end of each month, render to Seller a statement showing the quantity of gas delivered during that month and shall therewith pay Seller the amount due for all such gas.

5.4 Each party hereto shall have, at its expense, the right to examine the books and records of the other party to the extent necessary to verify the accuracy of any statement, charge, computation, or demand made under or pursuant to this

contract. Any statement shall be final as to both parties unless questioned in writing within two (2) years after payment thereof has been made.

5.5 The terms "upper Cook Inlet area" as used here in shall mean the area encompassed in a radius of 100 kilometers from the Phillips Petroleum North Cook Inlet platform.

ARTICLE VI

Term

6.1 This contract shall become effective upon the execution hereof and the approval of the Alaska Royalty Oil and Gas Development Advisory Board and the State Legislature and shall continue and remain in effect until July 1, 1984, unless terminated prior to such date by mutual agreement of the parties, or pursuant to Article VII.

ARTICLE VII

Conditions Precedent

7.1 Buyer shall have the right to terminate this contract upon 30 days written notice to Seller if Buyer is unable to make satisfactory arrangements to take delivery of the gas. Buyer shall exercise this right to terminate on or before January 31, 1978, thereafter Buyer may not exercise this right to terminate.

ARTICLE VIII

Notices

8.1 Notices required to be given under this contract shall be deemed sufficiently given and served when and if

deposited in the United States mail postage prepaid and certified or registered addressed to Seller at:

Commissioner
Department of Natural Resources
Pouch M, Juneau, Alaska 99811

or to Buyer at:

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in four (4) original counterparts on this day and year first above written.

"BUYER"

Harold B. Schmidt

STATE OF ALASKA

Guy R Martin

ATTEST:

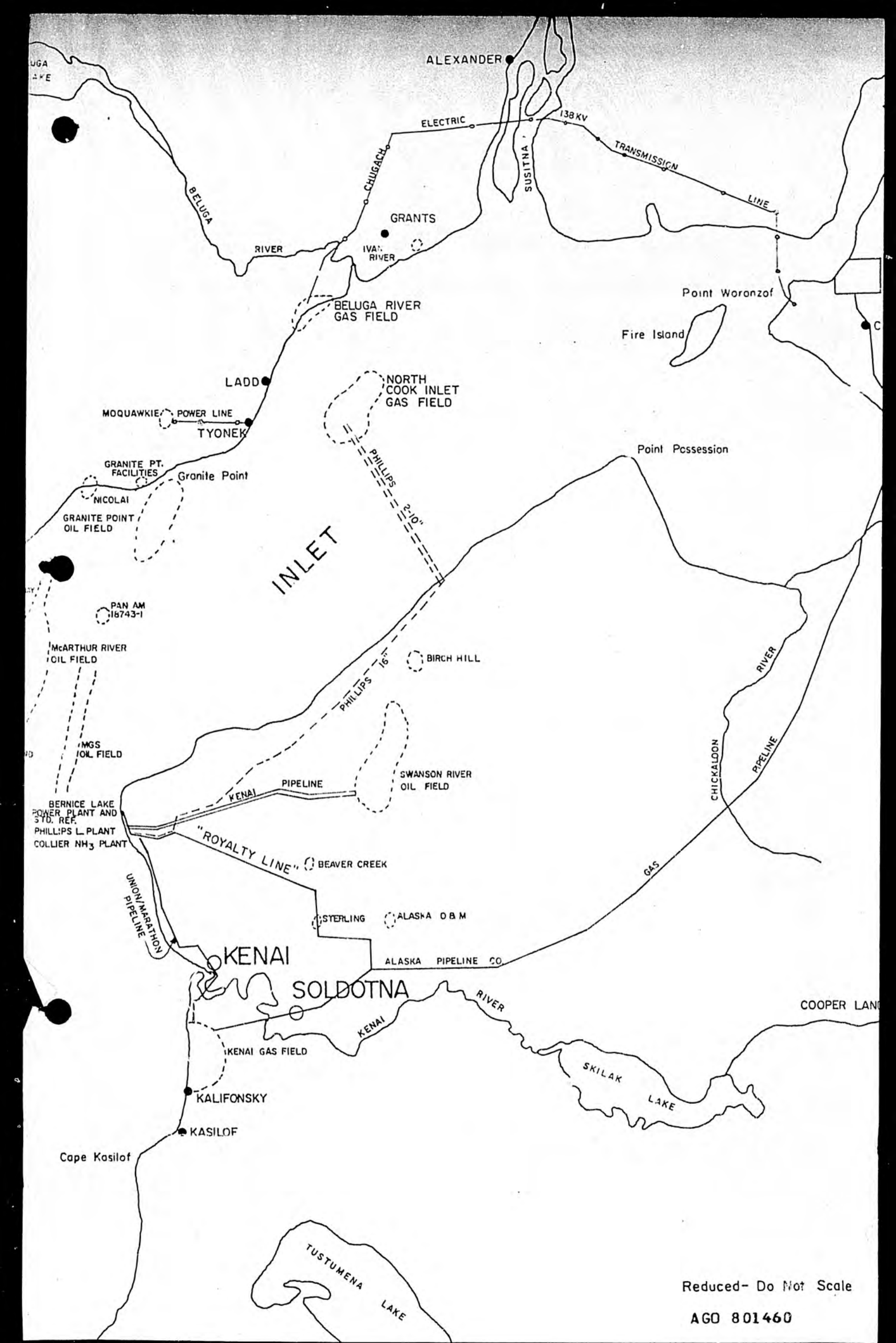
Richard F. Barner

ATTEST:

William C Fuchler

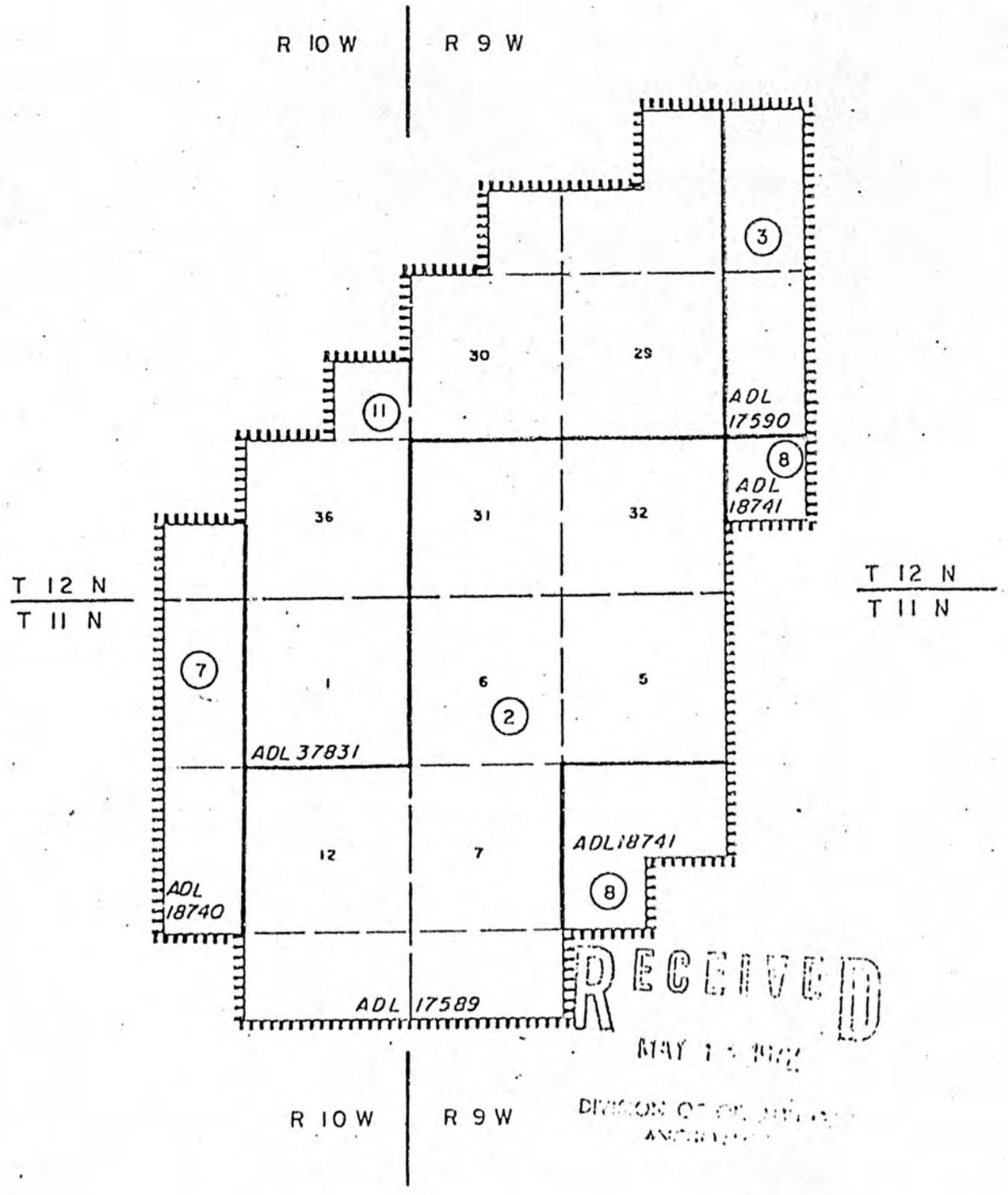
AGO 801458

MAPS



Reduced- Do Not Scale

AGO 801460



RECEIVED
MAY 1 1972
DIVISION OF OIL AND GAS
ANCHORAGE

(Contracted 2-1-72)

ADL 17589
ADL 17590
ADL 18740
ADL 18741
ADL 37831

LEGEND

Unit Boundary

Tract Boundary

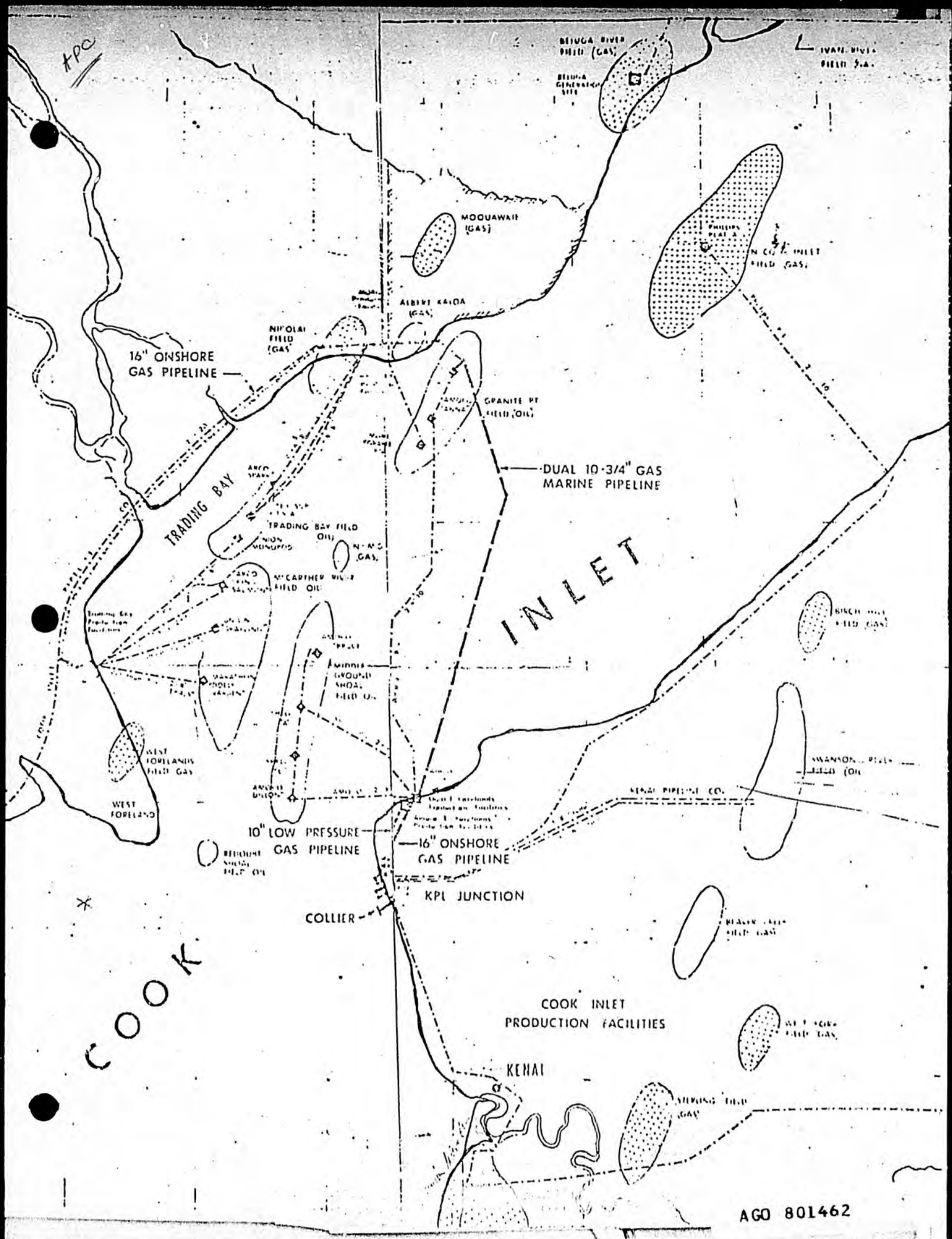
(3) Tract Number

EXHIBIT "A"
TO ACCOMPANY

CONTRACTED
NORTH COOK INLET
UNIT AGREEMENT

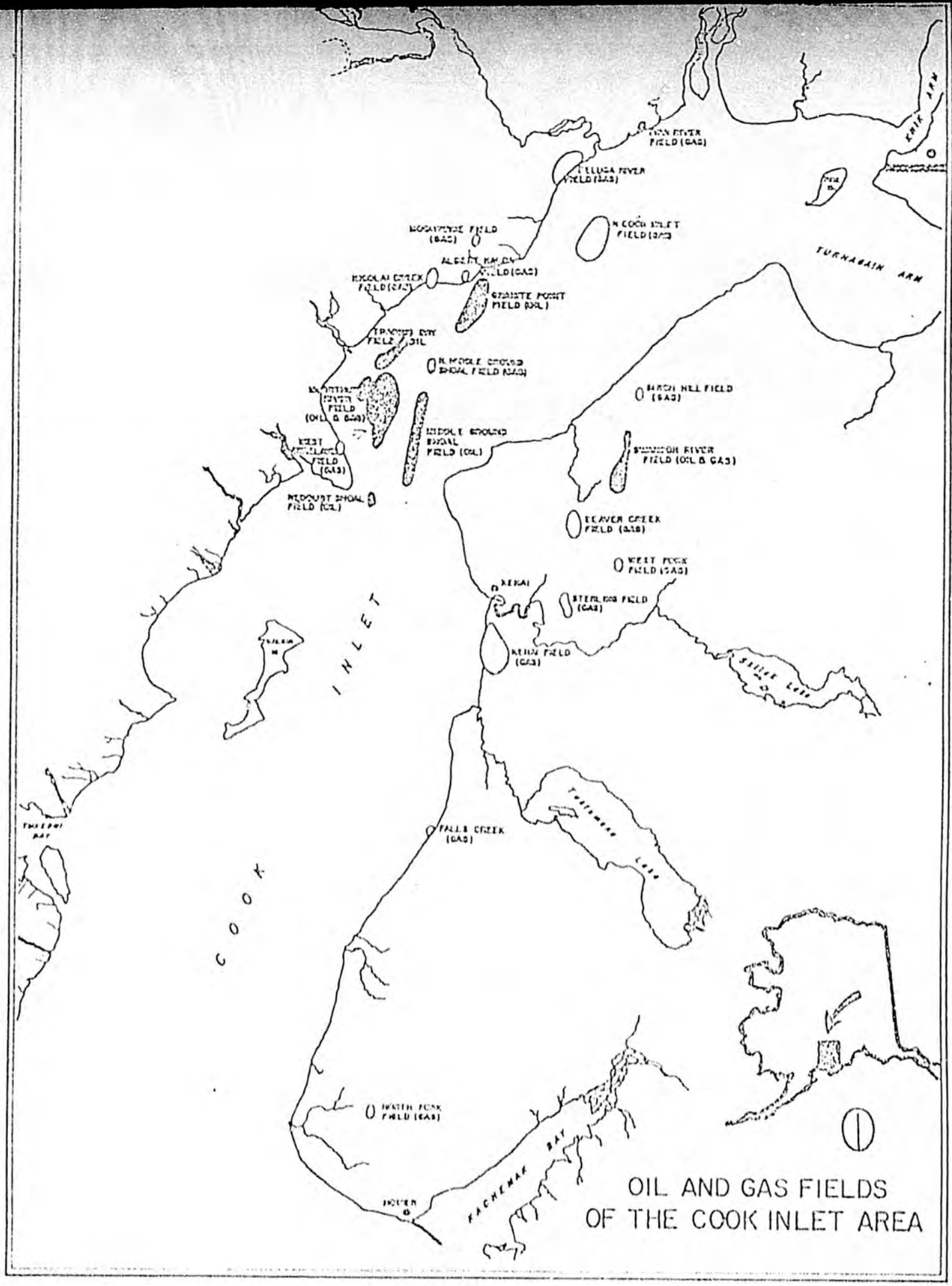
COOK INLET BASIN, ALASKA

Scale 1"=1mi Feb. '72

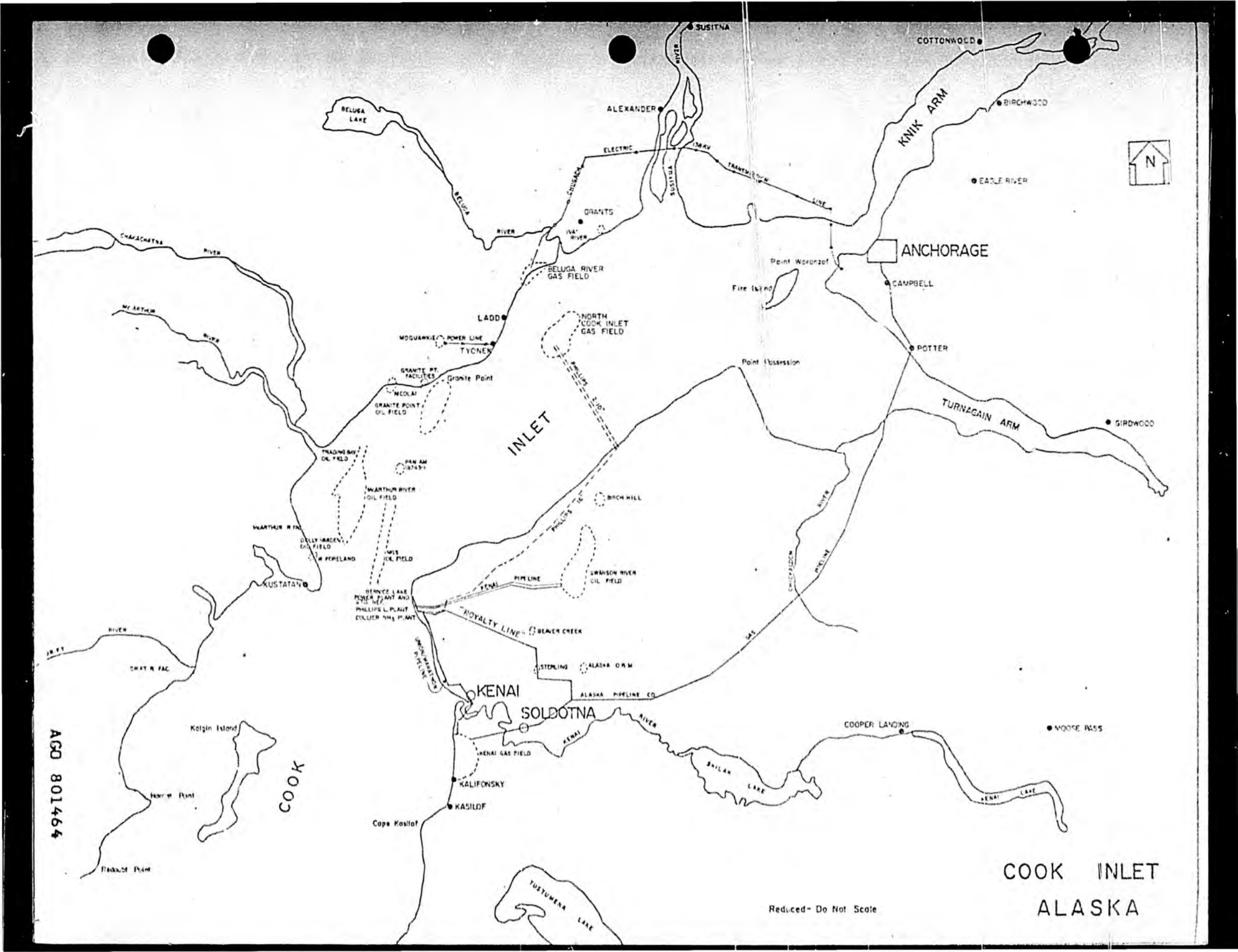


BELUGA RIVER FIELD (GAS)
IVAN RIVER FIELD
MOQUAWKIE (GAS)
N COOK INLET FIELD (GAS)
ALBERT KALOA (GAS)
NICOLAI FIELD (GAS)
16" ONSHORE GAS PIPELINE
GRANITE PT FIELD (OIL)
DUAL 10-3/4" GAS MARINE PIPELINE
TRADING BAY
TRADING BAY FIELD (OIL)
N MG (GAS)
McCARTHER RIVER FIELD OIL
INLET
MIDDLE GROUND SHOAL FIELD OIL
WEST FORELANDS FIELD GAS
WEST FORELAND
SWANSON RIVER FIELD (OIL)
KENAI PIPELINE CO.
10" LOW PRESSURE GAS PIPELINE
16" ONSHORE GAS PIPELINE
KPL JUNCTION
COLLIER
COOK
COOK INLET PRODUCTION FACILITIES
KENAI
STERLING FIELD (GAS)

AGO 801462


KNIK ARM
TURNAGAIN ARM
COOK INLET
KACHEMAK BAY
N. COOK INLET FIELD (GAS)
BIRCH HILL FIELD (GAS)
BEAVER CREEK FIELD (GAS)
WEST FORK FIELD (GAS)
KENAI
STERLING FIELD (GAS)
KENAI FIELD (GAS)
FALLS CREEK (GAS)
SOUTH FORK FIELD (GAS)
HOMER
OIL AND GAS FIELDS
OF THE COOK INLET AREA

AGO 801463


SUSITNA
COTTONWOOD
BIRCHWOOD
KNIK ARM
ALEXANDER
BELUGA LAKE
ELECTRIC
138KV
TRANSMISSION
LINE
SUSITNA
CHUGACH
BELUGA
RIVER
GRANTS
IVA RIVER
EAGLE RIVER
N
CHAKACHATNA
RIVER
ANCHORAGE
Point Woronzof
BELUGA RIVER GAS FIELD
Fire Island
CAMPBELL
McARTHUR
RIVER
LADD
NORTH COOK INLET GAS FIELD
MOQUAWKIE
POWER LINE
TYONEK
POTTER
Point Possession
GRANITE PT. FACILITIES
Granite Point
McCOLAI
GRANITE POINT OIL FIELD
INLET
TURNAGAIN ARM
GIRDWOOD
TRADING BAY OIL FIELD
PAN AM
McARTHUR RIVER OIL FIELD
BIRCH HILL
McARTHUR R FAC
DELLY VARDEN OIL FIELD
W FORELAND
MGS OIL FIELD
KUSTATAN
KENAI
PIPELINE
SWANSON RIVER OIL FIELD
BERNICE LAKE POWER PLANT AND
PHILLIPS L PLANT
COLLIER NH3 PLANT
"ROYALTY LINE"
BEAVER CREEK
RIVER
GAS
CHICKASCOW
PIPELINE
RIVER
DRIFT R FAC
STERLING
ALASKA O R M
KENAI
ALASKA PIPELINE CO
SOLDOTNA
Kalgin Island
COOPER LANDING
MOOSE PASS
KENAI
RIVER
KENAI GAS FIELD
SKILAK LAKE
COOK
KALIFONSKY
KENAI LAKE
Harriet Point
KASILOF
Cape Kasilof
Redoubt Point
TUSTUMENA LAKE
Reduced- Do Not Scale
COOK INLET
ALASKA

AGO 801464

LEGAL OPNS

+

APC + APUC

JURIS

LEGAL OPINIONS

APC AND APUC JURISDICTION

STATE
of ALASKA

MEMORANDUM

TO: Don Wold
Executive Director
Alaska Royalty Oil and Gas
Development Advisory Board

DATE: March 29, 1977

FILE NO:

TELEPHONE NO:

FROM: Wilson Condon
Deputy Attorney General

SUBJECT: Jurisdiction of the Alaska Pipeline Commission Over Phillips East Cook Inlet Gas Line

This is in response to your memorandum of March 11, 1977 in which you ask if the Alaska Pipeline Commission (APC) would have jurisdiction over a pipeline operated by Phillips Petroleum if State-owned royalty gas is transported over that pipeline to North Kenai Road, where it would be sold by the State to Alaska Pipeline Company, a wholly owned subsidiary of Alaska Gas and Service. My conclusion is that the APC would not have jurisdiction over the Phillips Petroleum Company pipeline.

The Alaska Pipeline Commission has jurisdiction over "pipelines", "pipeline facilities" and "pipeline carriers". AS 42.06.630(10) defines "pipeline carrier" as:

> . . . the owner, including corporations . . ., of any pipeline, as the term is defined in this section, or any interest in it;

AS 42.06.630(9) defines "pipeline" or "pipeline facility" as:

> . . . all the facilities of a total system of pipe . . . in this state used by a pipeline carrier for transportation, and for hire and as a common carrier, of oil or gas for delivery, storage, or further transportation, and including all pipe, pump and compressor stations, station equipment, and all other facilities used or necessary for an integral line of pipe to effectuate the transportation from point to point, excluding, however, gas processing plant, heaters and separators;

processing

? take out too?

What do they do

AGO 801467

The salient portion of the above definition is written in the conjunctive, i.e., to be a "pipeline" or "pipeline facility" under the Alaska Pipeline Commission Act, AS 42.06 et seq., a pipeline facility must be used ". . . for transportation, for hire and as a common carrier . . ." (emphasis added).

Of course Phillips, in the arrangement described at the outset of this memorandum, will be using its pipeline for "transportation" of gas. However, since the subject pipeline is neither operated by Phillips "as a common carrier" nor is it subject to the "common carrier" covenant requirement of AS 38.35.120 due to the fact that the lease of state lands for the subject pipeline pre-dates the enactment of that statute, the subject pipeline would not fall within the jurisdiction of the APC were the proposed arrangement to be entered into by Phillips.

WLC:RMB:jec

of ALASKA MEMORANDUM Ak Pipe Co.

TO: Guy Martin, Commissioner
Dept. of Natural Resources

DATE: March 7, 1977

FILE NO:

TELEPHONE NO:

FROM: Wilson Condon
Deputy Attorney General

SUBJECT: Jurisdiction of the APUC over Phillips Petroleum Pipeline

This is in response to your memorandum of February 24, 1977, in which you ask if the Alaska Public Utilities Commission would have jurisdiction over a pipeline operated by Phillips Petroleum if State-owned royalty gas is transported over that pipeline to North Kenai Road, where it would be sold by the State to Alaska Pipeline Company, a wholly owned subsidiary of Alaska Gas and Service. My conclusion is that the APUC would not have jurisdiction over the Phillips Petroleum Company pipeline.

The Alaska Public Utilities Commission has jurisdiction over "public utilities" which are defined by AS 42.05.70(2) as follows:

> "public utility" or "utility" includes every corporation (whether public, cooperative, or otherwise), company, individual, or association of individuals, their lessees, trustees, or receivers appointed by a court, that owns operates, manages or controls any plant, pipeline or system for
>
> * * *
>
> (D) furnishing by transmission or distribution of natural or manufactured gas to the Alaska public for compensation;
>
> * * *

"Public" is defined by AS 42.05.701(5) as follows:

> "public" or "general public" means
>
> (A) any group of 10 or more customers that purchase the service or commodity furnished by a public utility as defined in (2) of this section; and
>
> (B) any utility purchasing the product or service or paying for the transmission of electric energy, natural or manufactured gas, or petroleum products which are resold to a group included in (A) of this paragraph or which are used to produce the service or commodity sold to the public by the utility.

If Phillips delivers royalty natural gas to the State at the wellhead, and the State contracts with Phillips for transportation of that gas to North Kenai Road, Phillips will be rendering a utility-type service because it will be engaged in the transmission of natural gas. Phillips, however, will be neither a "utility" nor "public utility" within the meaning of the Public Utilities statute because it will not be furnishing transmission service to the "public" or the "Alaska public." Phillips would be furnishing transmission service to the State. This would make it a public utility if 1) the State is the 10th customer to purchase transmission service (our assumption is there are less than 10 purchasers of transmission service), or 2)if the State is a "utility. . . paying for the transmission of. . . natural. . . gas. . . which is resold to [any group of 10 or more customers that purchase the service or commodity furnished by a public utility. . .]." The State would not be a utility (because it does not fit within the definition of AS 42.05.701(2)), thus Phillips could not be a public utility subject to the jurisdiction of the APUC when it furnishes transmission service to the State.

WLC:FHB:bvd

cc: Frederick H. Boness
Assistant Attorney General

Robert E. Stoller
Assistant Attorney General

Alaska Roy Oil & Gas Dev. Adv. Bd.
Dec. 10 & 11, 1975

Board Meeting Called to order 10:10 a.m. Dec. 11, 1975, Chairman Martin brought the board back into session.

Mr. Martin:

We are at the point on theagenda where we take up discussions and reports. Fred I wonder if, Fred Boness from the Attorney Generals Office could just briefly outline the report that he filed on the Arn G-Phillips situation regard to public utilities.

Fred Boness:

At the last royalty board meeting Phillips raised the possibility that a sale of, or the state taking its gas in-kind might have the effect of subjecting the Phillips pipeline to either FPC or APUC jurisdiction depending on where the gas was sold. Specifically to APUC jurisdiction if it was sold to Anchorage Natural Gas Company. I reviewed that possibility and filed a memorandum with the commissioner which indicates that it was my conclusion that there was indeed a possibility that at least limited jurisdiction by the Public Utilities Commission and cited the situation which took place in the Marathon, the Union Marathon Pipeline which exists from the Kenai field to the ING plant. It does have sales off that to the City of Kenai and Anchorage Natural Gas and there is limited jurisdiction exercised by the PUC in that pipeline. I believe the situation would likely be an anologoas to the Phillips Pipeline.

Mr. Martin:

Fred, is it your view that, if jurisdiction applied, and you considred that a liklihood or at least the district possibility, could that jurisdiction be waived as a precedent.

Mr. Boness:

The Public Utility Commission does have the authority to grant exemptions under one of its provisions and that could be exercised. The exact, the exact determinance of whether it would be or not specified in the law and it would require a ruling by the APUC.

Mr. Martin:

Do you have any idea, or does anybody have any idea, what might be the time consideration on a waiver at that time?

Mr. Boness:

No, I'm afraid I don't. I haven't talked to the APUC. I would think it would be perhaps two, three-maybe not-I would not think more than six months. Certainly the APUC acts much faster and swifter than the FPC. I think we have that kind of comparison.

End discussion this topic.

guy Motion:

until all transportation or exchange arrangments have been completed to the satisfaction of the parties involved. Now detailing all aspects of that, I would like to point out some points. First: with regard to the termination date of the contract it is related to the termination of the Phillips contract and the possible implications of a failure Phillips to produce beyond that point. Second; the price is in fact, the highest price in the area and it is my feeling that this is an important aspect of the agreement for the reason that the board may very well, the baord and the state may very well, wish from time to time to be in the position of doing something which is unpalatable, as it is in this case, to remove royalty gas from the user that has served an important public purpose in the state. But the board I think and the state will not want to be in position of attempting to set prices from time to time and place to place and to chose from among consumers in the state. The safest and most consistent standard therefore should be the highest price and we intend that this term will bear that out. We have also indicated that the point of delivery will be the wellhead, and, while we believe that will substantially alter the nature of the original offer made by Alaska Pipeline Company, we believe it is quite important that the state not be responsible for that transportation to shore. That is be a negotiated item between Phillips and the purchaser. The state I should say at that point, that after having made this desision, fully intends that the decision be carried out and we think it is in the best public policy that this be carried out. I am requesting now and I think we will be requesting later that some terms of agreement, some measure of agreement, some point of agreement be found between Phillips and A N G for the delivery of this gas. I think that terminates my discussion with the exception of one point and that is that the PUC problme has not been one that has escaped our attention. It's our believe that this is a separate function, not one that the board can control as was suggested in the A N G offer. It was suggested in the A N G offer that the state would be capable of somehow dictating the outcome of that regulatory procedure. This, of course, is not the case, we will not attempt to do so. Now, I will indicate that it will be my intention to communicate the sentiments I just communicated with regard to our desire for success of this sale to the PUC with the request that they formulate the necessary procedures to protect Phillips from regulation in order to make this sale successful. So let me terminate my remarks at this time and ask for the Comments and response of the board.

John Horn:

Mr. Chairman, let me make one small comment, the expiration date of our contract with the Japanese is June 1, 1984 rather than May 1.

Mr. Martin:

Thank you, John, very much. I will amend that.

Essentially duplicates
APUC act 42.05.

Xerox 42.06.010 (1)
(2)
42.06.020

attorney general is legal counsel to APC

* 42.06.140 (1) + 42.06.630 (9)
(2) –
(3)
(8)
(9)
42.06.230
340 (A)
370 (a) + (b)
420
630

① What are "the performance of obligations under and compliance with the terms of the leases issued by the State"? (42.06.140 (2)).

(2) promote and insure, in conjunction with the Alaska Public Utilities Commission within its jurisdiction, nondiscriminatory, efficient, and economical oil and gas pipeline transportation at reasonable rates. (§ 1 ch 139 SLA 1972)

Article 2. Establishment of Alaska Pipeline Commission.

Section
20. Alaska Pipeline Commission created
30. Composition of Alaska Pipeline Commission
40. Term of office; vacancy
50. Removal of commissioners
60. Qualifications of commissioners
70. Quorum
80. Oath of office
90. Compensation of members of the Alaska Pipeline Commission
100. Principal office; seal
110. Legal counsel
120. Employment of commission personnel
130. Restrictions on commissioners and employees

Sec. 42.06.020. Alaska Pipeline Commission created. There is created within the Department of Commerce and Economic Development the Alaska Pipeline Commission, to regulate pipeline facilities and pipeline carriers, to regulate the access of information concerning pipeline facilities and carriers to this state, and to represent the interests of the state in any proceedings relating to them as provided for in this chapter. (§ 1 ch 139 SLA 1972; am § 85 ch 218 SLA 1976)

Effect of amendment. — The 1976 amendment substituted "Department of Commerce and Economic Development" for "Department of Commerce."

Sec. 42.06.030. Composition of Alaska Pipeline Commission. (a) The Alaska Pipeline Commission consists of three members, appointed by the governor and confirmed by a majority of the members of the legislature in joint session.

(b) The governor shall designate one member of the commission as chairman of the commission. This member shall serve as chairman for a term of two years, and may be appointed for successive terms. (§ 1 ch 139 SLA 1972)

Editor's note. — Section 2, ch. 139, SLA 1972, provides: "Notwithstanding the provisions of AS 42.06.030 — 42.06.040, until July 1, 1973 the duties and functions of the Alaska Pipeline Commission under AS 42.06 may, by executive order of the governor, be carried out by a single commissioner appointed and paid under the provisions of AS 42.06 and two temporary commissioners who shall be appointed for terms expiring July 1, 1973. Temporary commissioners shall receive no compensation except per diem and travel authorized by law for other state boards and commissions and are not subject to the provisions of AS 42.06.060."

Sec. 42.06.040. Term of office; vacancy. (a) The members of the commission shall be appointed for terms of six years, except that of the members first appointed to the commission, one shall be appointed for a term of two years, one for a term of four years, and one for a term

regulation hereunder unless 25 per cent of the subscribers petition the commission for regulation. (§ 6 ch 113 SLA 1970; am § 3 ch 76 SLA 1973)

Effect of amendment. — The 1973 amendment inserted the language beginning "excepting" and ending "waste material" in the first sentence of subsection (b), substituted "the" for "such an" in that sentence, and added the second sentence of that subsection.

Sec. 42.05.721. Short title. This chapter may be cited as the Alaska Public Utilities Commission Act. (§ 6 ch 113 SLA 1970)

Editor's note.—Section 7, ch. 113, SLA 1970, provides: "All litigations, hearings, investigations, and other proceedings whatsoever, pending under any law repealed by this Act, shall continue and remain in full force and effect, and may be continued and completed under the provisions of this act. All certificates, orders, rules, regulations, or tariffs, made, issued, or filed under any law repealed by this Act, and in full force and effect on July 1, 1970, shall remain in full force and effect for the term issued, or until revoked, vacated, or modified under the provisions of this Act. All existing contracts and obligations of the commission, entered into or created under any law repealed by this Act, and in force and effect on July 1, 1970, shall remain in full force and effect and shall continue to be performed by the commission. The existing rates, charges, tariffs, rules, regulations, service and service area of the municipally owned utility shall continue and remain in full force and effect unless otherwise ordered by the commission under the provisions of this Act."

Legislative committee report. — For report on ch. 113, SLA 1970 (SCSCSHB 202 am S), see 1969 House Journal, p. 549, and Supplement No. 4 (4/9/69).

Chapter 06. Alaska Pipeline Commission Act.

Article
1. Declaration of Policy (§ 42.06.010)
2. Establishment of Alaska Pipeline Commission (§§ 42.06.020 — 42.06.130)
3. Powers and Duties of Commission (§ 42.06.140 — 42.06.640)

Legislative committee report. — For report on ch. 139, SLA 1972 (FCCS HCS CSSB 314), see 1972 Senate Journal, p. 1072; 1972 House Journal, p. 1420.

Article 1. Declaration of Policy.

Section
10. Legislative declaration of policy

Sec. 42.06.010. Legislative declaration of policy. The transportation of oil or gas by pipeline in the state is a business involved with the public interest. It is the purpose of this chapter to

(1) promote and oversee the development of an oil and gas pipeline transportation system in the state properly adapted to the present and future needs of the domestic commerce of the state and of the interstate and foreign commerce of the United States;

AGO 801475

(2) promote and insure, in conjunction with the Alaska Public Utilities Commission within its jurisdiction, nondiscriminatory, efficient, and economical oil and gas pipeline transportation at reasonable rates. (§ 1 ch 139 SLA 1972)

Article 2. Establishment of Alaska Pipeline Commission.

Section
20. Alaska Pipeline Commission created
30. Composition of Alaska Pipeline Commission
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90. Compensation of members of the Alaska Pipeline Commission
100. Principal office; seal
110. Legal counsel
120. Employment of commission personnel
130. Restrictions on commissioners and employees

Sec. 42.06.020. Alaska Pipeline Commission created. There is created within the Department of Commerce and Economic Development the Alaska Pipeline Commission, to regulate pipeline facilities and pipeline carriers, to regulate the access of information concerning pipeline facilities and carriers to this state, and to represent the interests of the state in any proceedings relating to them as provided for in this chapter. (§ 1 ch 139 SLA 1972; am § 85 ch 218 SLA 1976)

Effect of amendment. — The 1976 amendment substituted "Department of Commerce and Economic Development" for "Department of Commerce."

Sec. 42.06.030. Composition of Alaska Pipeline Commission. (a) The Alaska Pipeline Commission consists of three members, appointed by the governor and confirmed by a majority of the members of the legislature in joint session.

(b) The governor shall designate one member of the commission as chairman of the commission. This member shall serve as chairman for a term of two years, and may be appointed for successive terms. (§ 1 ch 139 SLA 1972)

Editor's note. — Section 2, ch. 139, SLA 1972, provides: "Notwithstanding the provisions of AS 42.06.030 — 42.06.040, until July 1, 1973 the duties and functions of the Alaska Pipeline Commission under AS 42.06 may, by executive order of the governor, be carried out by a single commissioner appointed and paid under the provisions of AS 42.06 and two temporary commissioners who shall be appointed for terms expiring July 1, 1973. Temporary commissioners shall receive no compensation except per diem and travel authorized by law for other state boards and commissions and are not subject to the provisions of AS 42.06.060."

Sec. 42.06.040. Term of office; vacancy. (a) The members of the commission shall be appointed for terms of six years, except that of the members first appointed to the commission, one shall be appointed for a term of two years, one for a term of four years, and one for a term

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Sec. 42.06.130. Restrictions on commissioners and employees. No member or employee of the commission may have an official connection with, or hold stock or securities in, or have a pecuniary interest in, a corporation, company or association engaged in the production or the transportation of oil or gas. No member or employee may act upon a matter in which his relationship with any person creates a conflict of interest. (§ 1 ch 139 SLA 1972)

Article 3. Powers and Duties of Commission.

Section

140. Powers and duties of the commission
150. Powers and duties with respect to federally regulated carriers
160. Administrative authority of commission; regulations and hearing procedures
170. Application of Administrative Procedure Act
180. Formal hearings
190. Final orders of the commission
200. Format of orders
210. Publication of reports, orders, decisions and regulations
220. Annual report
230. Jurisdiction of commission
240. Certificate required
245. Federally regulated carriers
250. Application
260. Public hearings
270. Grant or denial of application
280. Insurance and security
290. Abandonment
300. Modification, suspension or revocation of certificates
305. Transfer of certificate
310. Standards of service and facilities
320. Discrimination in service
330. Power of commission to allocate usage
340. Order for joint use or connection
350. Tariffs, contracts, filing and public inspection
360. Adherence to tariffs

Section

370. Rates to be just and reasonable
380. Discrimination in rates
390. New or revised tariffs
400. Suspension of tariff filing
410. Power of commission to fix rates
420. Valuation of property of a pipeline carrier
430. General provisions as to accounts, records and reports
440. Inspection of records
450. Investigation of management practices
460. Designation of service agents
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480. Review and enforcement
490. Complaint against pipeline carrier
500. Adjudication by commission under Administrative Procedure Act
510. Public records
520. Application fees
530. Injunctive and monetary sanctions
540. Civil penalties
550. Each violation a separate ofrense
560. Actions to recover damages and penalties; disposition
570. Penalties cumulative
580. Joinder of actions
590. Private cause of action
600. Regulation by municipality
610. Expenses of investigation or hearing
620. Classification
630. Definitions
640. Short title

Sec. 42.06.140. Powers and duties of the commission. The commission

(1) shall regulate pipelines and pipeline carriers in the state;

(2) may investigate upon complaint or its own motion, the rates, classifications, rules, regulations, prices, services, practices and facilities of pipeline carriers, and the performance of obligations under and compliance with the terms of leases issued by the state;

(3) may make, prescribe or require just, fair and reasonable rates, classifications, regulations, practices, services and facilities for pipeline carriers;

(4) may require pipeline carriers to file with the commission reports and other information and data required or permitted to be required by other provisions of this chapter;

(5) may adopt regulations that are necessary and proper to the performance of its duties under this chapter, including regulations governing practices and procedures of the commission, which regulations shall not be inconsistent with state law;

(6) shall during normal business hours have access to and may designate any of its employees, agents or consultants to inspect and examine, the accounts, financial and property records, books, maps, inventories, appraisals, valuations, and related reports kept by a pipeline carrier, or kept for it by others, which directly affect the interests of the state and directly relate to pipelines located in the state;

(7) may initiate, intervene in, and appear personally or by counsel and offer evidence in and participate in, any proceedings involving a pipeline carrier, and affecting the interests of the state, before any officer, department, board, commission or court of this state;

(8) shall require permits for the construction, enlargement in size or operating capacity, extension, operation or abandonment of any oil or gas pipeline facility, subject to necessary and reasonable terms, conditions and limitations;

(9) may prescribe the system of accounts and regulate the service of an oil or gas pipeline facility;

(10) shall provide all reasonable assistance to the Department of Law in intervening in, offering evidence in, and participating in proceedings involving a pipeline carrier and affecting the interests of the state, before an officer, department, board, commission or court of another state or the United States. (§ 1 ch 139 SLA 1972; am §§ 1, 2 ch 201 SLA 1976)

Effect of amendment. — The 1976 amendment deleted "or of another state or of the United States" from the end of paragraph (7) and added paragraph (10).

Sec. 42.06.150. Powers and duties with respect to federally regulated carriers. Section 140 of this chapter applies to oil and gas pipeline carriers regulated under the Interstate Commerce Act of 1906, or the Natural Gas Act of 1938, only to the extent not preempted under those federal Acts. (§ 1 ch 139 SLA 1972)

Sec. 42.06.160. Administrative authority of commission; regulations and hearing procedures. (a) The commission may adopt regulations, not inconsistent with law, necessary or proper to exercise its powers and to perform its duties under this chapter.

(b) The commission shall adopt regulations governing practice and procedure, consistent with due process of law, including the conduct of formal and informal investigations, prehearing conferences, hearings and proceedings, and the handling of procedural motions by a single

Sec. 42.06.210. Publication of reports, orders, decisions and regulations. All reports, orders, decisions and regulations of the commission shall be in writing. The commission shall apprise all affected operators of oil or gas pipeline facilities and interested parties of these reports, orders, decisions, and regulations as they are issued and adopted, and, when appropriate to do so, publish them in a manner that will reasonably inform the public or the affected consumers of the services of any oil or gas pipeline facility. The commission may set charges for costs of printing or reproducing and furnishing copies of its reports, orders, decisions and regulations. The publication requirement, as it pertains to regulations, does not supersede the requirements of the Administrative Procedure Act (AS 44.62). (§ 1 ch 139 SLA 1972)

Sec. 42.06.220. Annual report. The commission shall publish an annual report reviewing its work and submit it to the legislature by February 15 of each year. The report shall contain information and data which bear a significant relationship to the development and regulation of oil or gas pipeline facilities in the state and include an outline of the commission's program for the development and regulation of oil or gas pipeline facilities in the forthcoming year. (§ 1 ch 139 SLA 1972)

Sec. 42.06.230. Jurisdiction of commission. Except as otherwise provided in this chapter or hereafter otherwise expressly provided by law, except as to any concurrent jurisdiction with the Alaska Public Utilities Commission under ch. 5 of this title as to a public utility described in AS 42.05.701(2)(D) and (E), and except as to jurisdiction of the Department of Law as provided by § 140(10) of this chapter, the jurisdiction and authority over the subject matter of this chapter is exclusively in the commission. To the extent that the performance of any duties of the commission affect a pipeline carrier or a pipeline subject to the Interstate Commerce Act or the Natural Gas Act, the performance of its duties shall not, as to that pipeline carrier or pipeline, conflict with applicable federal laws, regulations, rules, orders, or other requirements. (§ 1 ch 139 SLA 1972; am § 3 ch 201 SLA 1976)

Effect of amendment. — The 1976 amendment, in the first sentence, deleted "and" preceding "except as to any concurrent jurisdiction" and inserted "and except as to jurisdiction of the Department of Law as provided by § 140(10) of this chapter."

Sec. 42.06.240. Certificate required. (a) After January 1, 1974 no pipeline carrier, or person which will be a pipeline carrier upon completion of any proposed construction or extension, shall engage in the transportation of oil or gas by pipeline subject to the jurisdiction of the commission, or undertake the construction or extension of any pipeline facilities for that purpose, or acquire or operate any pipeline facilities or extension, unless there is in force with respect to that pipeline carrier a certificate of public convenience and necessity issued

(b) If the commission, upon its own motion or upon complaint, after providing reasonable notice and opportunity for hearing, finds that the service or facilities of an oil or gas pipeline facility are unreasonable, unsafe, inadequate, insufficient, or unreasonably discriminatory, or otherwise in violation of this chapter, the commission shall prescribe by regulation or order, the reasonable, safe, adequate, sufficient service or facilities to be observed, furnished, enforced, or employed, including all repairs, changes, alterations, extensions, substitutions, or improvements in facilities that are reasonably necessary and proper for the safety, accommodation, and convenience of the public and the users. Regulations or orders issued under this subsection shall conform to accepted industry standards and practices.

(c) Every common carrier shall, when order by the Alaska Pipeline Commission, extend or enlarge its pipeline or storage facilities provided the extension or enlargement shall be found to be reasonable and required in the public interest and that the expense involved will not impair the ability of the common carrier or public utility to perform its duty to the public. (§ 1 ch 139 SLA 1972; am § 29 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment added subsection (c).

Sec. 42.06.320. Discrimination in service. No oil or gas pipeline carrier may, as to service, make or grant an unreasonable preference or advantage to any person or subject any person to an unreasonable prejudice or disadvantage. No oil or gas pipeline facility which is owned by more than one owner may require that users make separate requests of each separate owner in order to obtain a reasonable share of the service provided by the oil or gas pipeline facility. (§ 1 ch 139 SLA 1972)

Sec. 42.06.330. Power of commission to allocate usage. If the commission, upon its own motion or upon complaint, after providing reasonable notice and opportunity for hearing, finds that an oil or gas pipeline facility is making or granting an unreasonable preference or advantage to any person or subjecting any person to an unreasonable prejudice or discrimination, the commission may prescribe rules to end the discrimination or the commission may itself prescribe the allocation of the service until it determines the discrimination can be avoided by appropriate rule or agreement. (§ 1 ch 139 SLA 1972)

Sec. 42.06.340. Order for joint use or connection. (a) When there is failure to agree upon the joint use or interconnection of oil or gas pipeline facilities or the conditions or compensation for joint use or interconnections, any interested person may apply to the commission for an order requiring the interconnection. If, after investigation and opportunity for hearing, the commission finds that public convenience and necessity require the joint use or connection, and that the use or

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connection will not result in substantial injury to the oil or gas pipeline facility or its customers, or in substantial detriment to the services furnished by the oil or gas pipeline facility, or in the creation of safety hazards, it shall

(1) order that the use be permitted;

(2) prescribe reasonable conditions and compensation for the joint use;

(3) order the interconnection to be made;

(4) determine the time and manner of the interconnection;

(5) determine the apportionment of costs and responsibility for operation and maintenance of the interconnection.

(b) During construction of a pipeline the commission, after investigation and opportunity for hearing and findings as required in (a) of this section, may order the inclusion within the pipeline at points that it designates, special fittings including but not limited to tees, wyes, spools, reducers, enlargers, flanges, flange plates, valves and valve boxes, to reduce the time and cost of future connections for the injection and removal of gas and oil from the main pipeline, and to maintain and facilitate intrastate commerce. A request for special fittings may be made by the commissioner of natural resources for the state. A request for special fittings and valves may be made to the commission by a local government, person, company or corporation. The cost of furnishing and installing the special fittings shall be paid by the state. However, if the special fittings are used by a person for a commercial enterprise or by a municipality for the operation of a utility, the commission shall require that the using person or municipality reimburse the state for the cost of furnishing and installing. (§ 1 ch 139 SLA 1972; am § 1 ch 5 SSSLA 1974)

Effect of amendment. — The 1974 amendment added subsection (b).

Sec. 42.06.350. Tariffs, contracts, filing and public inspection. (a) Under such regulations as the commission shall prescribe, every intrastate oil or gas pipeline carrier shall file with the commission, within the time and in the form designated by the commission, all rates, tariffs, charges, classifications, rules, regulations, terms, and conditions pertaining to service provided under the certificate, and shall maintain copies on file at its principal business office and at places designated by the commission, available to, and subject to inspection by, the general public on demand.

(b) The commission may reject the filing of all or part of a tariff which does not comply with the form or filing regulations of the commission or which is not consistent with this chapter or the regulations of the commission. A tariff or provision so rejected is void. (§ 1 ch 139 SLA 1972)

Sec. 42.06.360. Adherence to tariffs. The terms and conditions under which a pipeline carrier offers its services and facilities to the public

shall be governed strictly by the provisions of its currently effective tariffs. No legally filed and effective tariff rate, charge, rule, regulation or condition of service may be changed except in the manner provided in this chapter. If more than one tariff rate or charge can reasonably be applied for billing purposes the one most advantageous to the customer shall be used. (§ 1 ch 139 SLA 1972)

Sec. 42.06.370. Rates to be just and reasonable. (a) All rates demanded or received by a pipeline carrier, or by any two or more pipeline carriers jointly, for a service furnished or to be furnished shall be just and reasonable.

(b) Additional regulations and rules governing determination of a reasonable tariff shall be published by the commission. (§ 1 ch 139 SLA 1972)

Sec. 42.06.380. Discrimination in rates. (a) No pipeline carrier may, as to rates, grant a preference or advantage to any customer or subject a customer to an unreasonable prejudice or disadvantage. No pipeline carrier may establish or maintain an unreasonable difference as to rates, either as between localities served or between classes of service provided under the certificate.

(b) No pipeline carrier may directly or indirectly refund, rebate or remit in any manner, or by any device, any portion of the rates and charges or charge, demand or receive a greater or lesser compensation for service than is specified in its effective tariff nor extend to any customer served under the certificate any form of contract, agreement, inducement, privilege or facility, or apply any rule, regulation or condition of service except as are extended or applied to all customers under like circumstances. (§ 1 ch 139 SLA 1972)

Sec. 42.06.390. New or revised tariffs. (a) No pipeline carrier may establish or place in effect any new or revised rates, charges, rules, regulations, conditions of service or practices except after 30 days notice to the commission and to the public. Notice shall be given by filing with the commission and keeping open for public inspection the revised tariff provisions which shall plainly indicate the changes to be made in the schedules then in force and the time when the changes will go into effect. The commission may prescribe additional means of giving notice. The commission, for good cause shown, may allow changes to take effect on less than 30 days notice under conditions the commission prescribes.

(b) New and revised tariffs shall be filed in the manner provided in § 350 of this chapter. (§ 1 ch 139 SLA 1972)

Sec. 42.06.400. Suspension of tariff filing. (a) When a tariff filing is made containing a new or revised rate, classification, rule, regulation, practice, or condition of service the commission may, either upon written complaint or upon its own motion, after reasonable notice, conduct a hearing to determine the reasonableness and propriety of the filing.

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Pending a hearing the commission may, by order stating the reasons for its action, suspend the operation of the tariff filing for an initial period not longer than six months beyond the time when it would otherwise go into effect.

(b) An order suspending a tariff filing may be vacated if, after investigation, the commission finds that it is in all respects proper. Otherwise the commission shall hold a hearing on the suspended filing and issue its order, before the end of the suspension period, granting, denying or modifying the suspended tariff in whole or in part.

(c) In the case of a proposed increased rate, the commission may by order require the interested pipeline carrier to place in escrow in a financial institution approved by the commission, and keep accurate account of, all amounts received by reason of the increase, specifying by whom and in whose behalf the amounts are paid. Upon completion of the hearing and decision the commission may by order require the pipeline carrier to refund to the persons in whose behalf the amounts were paid, that portion of the increase in rates which was found to be unreasonable or unlawful. No funds may be released from escrow without the commission's prior written consent and the escrow agent shall be so instructed by the pipeline carrier, in writing, with a copy to the commission. The pipeline carrier, at its expense, may substitute a bond in lieu of the escrow requirement.

(d) One who initiates a change in existing tariffs bears the burden of proving the reasonableness of the change. (§ 1 ch 139 SLA 1972)

Sec. 42.06.410. Power of commission to fix rates. When the commission, after an investigation and hearing, finds that a rate demanded, observed, charged or collected by a pipeline carrier for a service, subject to the jurisdiction of the commission, or that a classification, rule, regulation, practice, or contract affecting the rate, is unjust, unreasonable, unduly discriminatory or preferential, the commission shall determine a just and reasonable rate, classification, rule, regulation, practice, or contract to be observed or allowed and shall establish it by order. (§ 1 ch 139 SLA 1972)

Sec. 42.06.420. Valuation of property of a pipeline carrier. The commission may, after providing reasonable notice and opportunity to be heard, ascertain and set the fair value of the whole or any part of the property of a pipeline carrier, insofar as it is material to the exercise of the jurisdiction of the commission. The commission may make revaluations from time to time and ascertain the fair value of all new construction, extensions, and additions to the property of a pipeline carrier. (§ 1 ch 139 SLA 1972)

Sec. 42.06.430. General provisions as to accounts, records and reports. To the extent necessary to the performance of the duties of the commission as provided in this chapter:

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Sec. 42.06.600. Regulation by municipality. The commission's jurisdiction and authority extend to an oil or gas pipeline facility operating in a city or borough, whether home rule or otherwise. If a conflict between a certificate, order, decision or regulation of the commission and a charter, permit, franchise, ordinance, rule or regulation of such a local governmental entity occurs, the certificate, order, decision or regulation of the commission prevails. (§ 1 ch 139 SLA 1972)

Sec. 42.06.610. Expenses of investigation or hearing. After completion of a hearing or investigation held under this chapter, the commission shall allocate the costs of the hearing or investigation among the parties, including the commission, as is just under the circumstances. The costs allocated may include the costs of any time devoted to the investigation or hearing by hired consultants, whether or not the consultants appear as witnesses or participants. The commission shall provide an opportunity for any person objecting to an allocation to be heard before the allocation becomes final. (§ 1 ch 139 SLA 1972)

Sec. 42.06.620. Classification. The commission may by regulation provide for the classification of oil or gas pipeline facilities based upon differences in annual revenue, assets, nature of ownership and other appropriate distinctions and as between these classifications, by regulation, provide for different reporting, accounting and other regulatory requirements. (§ 1 ch 139 SLA 1972)

Sec. 42.06.630. Definitions. In this chapter

(1) "commission" means the Alaska Pipeline Commission;

(2) "commissioner" means a member of the commission;

(3) "duties" means duties, powers, obligations and functions;

(4) "gas" includes all natural gas and hydrocarbons produced at the wellhead and not defined as oil;

(5) "Interstate Commerce Act" means the Interstate Commerce Act of 1906, 34 Stat. 584, as amended;

(6) "municipality" means an organized borough or incorporated city;

(7) "Natural Gas Act" means the Natural Gas Act of 1938, 52 Stat. 821, as amended;

(8) "oil" includes crude oil, and other hydrocarbons regardless of gravity which are produced at the wellhead in liquid form, its products and liquid hydrocarbons, including the liquid hydrocarbons known as distillate or condensate recovered or extracted from gas, other than gas produced in association with oil and commonly known as casinghead gas;

(9) "pipeline" or "pipeline facility" means all the facilities of a total system of pipe (whether owned or operated by a pipeline carrier under a contract, agreement, or lease) in this state used by a pipeline carrier for transportation, for hire and as a common carrier, of oil or gas for delivery, storage, or further transportation, and including all pipe, pump and compressor stations, station equipment, and all other facilities used

or necessary for an integral line of pipe to effectuate the transportation from point to point, excluding, however, gas processing plants, treaters and separators;

(10) "pipeline carrier" means the owner, including corporations organized under the laws of the United States or of other states, of any pipeline, as the term is defined in this section, or any interest in it;

(11) "regulation" includes rules;

(12) "tariff" means a rate, charge, toll, rule or regulation of an oil or gas pipeline facility relating to services furnished by the facility to the general public or other users for compensation. (§ 1 ch 139 SLA 1972; am §§ 7, 8 ch 6 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote paragraphs (4) and (8).

Sec. 42.06.640. Short title. This chapter may be cited as the Alaska Pipeline Commission Act. (§ 1 ch 139 SLA 1972)

Chapter 07. Alaska Transportation Commission Act.

Article
1. Establishment of Transportation Commission (§§ 42.07.011 — 42.07.111)
2. Powers and Duties of Commission (§§ 42.07.121 — 42.07.161)

Repeal of former chapter. — Section 1, ch. 104, SLA 1969, repealed former Chapter 07, entitled "Alaska Transportation Commission." The former chapter consisted of §§ 42.07.010 — 42.07.159, and derived from § 1, ch. 139, SLA 1966.

Article 1. Establishment of Transportation Commission.

Section
11. Creation and composition
21. Term of office; vacancy
31. Quorum
41. Qualifications
51. Oath of office
61. Restrictions
71. Compensation of members of the Alaska Transportation Commission
81. Principal office and seal
91. Legal counsel
101. Employment and compensation of personnel
111. Annual report

Sec. 42.07.011. Creation and composition. (a) There is created the Alaska Transportation Commission within the Department of Commerce and Economic Development. The commission consists of three members appointed by the governor and confirmed by the legislature in joint session.

(b) The governor shall designate one member of the commission as chairman of the commission. This member shall serve as chairman for

to comply with its terms, conditions, and obligations. Only upon proper acceptance of offered lease by the applicant within 30 days after its having been presented is the grant of the application consummated. (§ 1 ch 72 SLA 1972; am § 9 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.110. Term of lease. Each lease of state land for pipeline right-of-way purposes shall contain a provision that the lease shall run for a specified term of not greater than 30 years, and shall be renewable for additional periods of up to 10 years each, so long as the lessee is in commercial operation and is in full compliance with all state law, including but not limited to state law pertaining to regulation and taxation of the pipeline facility, and is in compliance with all terms of the lease. In making this determination he shall take into consideration the cost of the proposed pipeline, its useful life, and the probable financing requirement for the proposed pipeline. (§ 1 ch 72 SLA 1972; am § 10 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment substituted "30 years" for "25 years" and inserted "is in commercial operation and" in the first sentence and added the second sentence.

Sec. 38.35.120. Covenants required to be included in lease. (a) A noncompetitive lease of state land for a right-of-way for an oil or natural gas pipeline valued at $1,000,000 or more may be granted only upon the condition that the lessee expressly covenants in the lease, in consideration of the rights acquired by it under the lease, that

(1) it assumes the status of and will perform all of its functions undertaken under the lease as a common carrier and will accept, convey, and transport without discrimination crude oil or natural gas, depending on the kind of pipeline involved, delivered to it for transportation from fields in the vicinity of the pipeline subject to the lease throughout its route both on state land obtained under the lease and on other land; however, a lessee who owns or operates a natural gas pipeline subject to regulation either (A) under the Natural Gas Act (15 U.S.C. 717 et seq.) of the United States, or (B) by the state or political subdivisions with respect to rates and charges for the sale of natural gas, is, to the extent of that regulation, exempt from the common carrier requirement in this paragraph; it will accept, convey, and transport crude oil or natural gas without unjust or unreasonable discrimination in favor of one producer or person, including itself, as against another but will take the crude oil or natural gas, depending on the kind of pipeline involved, delivered or offered, without unreasonable discrimination, that the Alaska Pipeline Commission shall, after a full hearing with due notice to the interested parties and a proper finding of facts, determine to be reasonable in the performance of its duties as a common carrier;

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(2) it will interchange crude oil or natural gas, depending on the kind of pipeline involved, with each like common carrier and provide connections and facilities for the interchange of crude oil or natural gas at every locality reached by both pipelines when the necessity exists, subject to rates and regulations made by the appropriate state or federal regulatory agency;

(3) it will maintain and preserve books, accounts, and records and will make those reports that the state may prescribe by regulation or law as necessary and appropriate for purposes of administration of this chapter;

(4) it will accord at all reasonable times to the state and its authorized agents and auditors the right of access to its property and records, of inspection of its property, and of examination and copying of records;

(5) it will provide connections, as determined by the Alaska Pipeline Commission under AS 42.06.340, to facilities on the pipeline subject to the lease, both on state land and other land in the state, for the purpose of delivering crude oil or natural gas, depending on the kind of pipeline involved, to persons (including the state and its political subdivisions) contracting for the purchase at wholesale of crude oil or natural gas transported by the pipeline when required by the public interest;

(6) it shall, notwithstanding any other provision, provide connections and interchange facilities at state expense at such places the state considers necessary if the state determines to take a portion of its royalty or taxes in oil or natural gas;

(7) it will construct and operate the pipeline in accordance with applicable state laws and lawful regulations and orders of the Alaska Pipeline Commission;

(8) it will, at its own expense, during the term of the lease

(A) maintain the leasehold and pipeline in good repair;

(B) promptly repair or remedy any damage to the leasehold;

(C) promptly compensate for any damage to or destruction of property for which the lessee is liable resulting from damage to or destruction of the leasehold or pipeline;

(9) it will not transfer, assign, or dispose of in any manner, directly or indirectly, or by transfer of control of the carrier corporation, its interest in a right-of-way lease, or any rights under the lease or any pipeline subject to the lease to any person other than another owner of the pipeline (including subsidiaries, parents and affiliates of the owners), except to the extent that the commissioner, after consideration of the protection of the public interest (including whether the proposed transferee is fit, willing and able to perform the transportation or other acts proposed in a manner that will reasonably protect the lives, property and general welfare of the people of Alaska), authorizes; the commissioner shall not unreasonably withhold his consent to the transfer, assignment or disposal;

(10) it will file with the commissioner a written appointment of a named permanent resident of the state to be its registered agent in the state and to receive service of notices, regulations, decisions and orders of the commissioner; if it fails to appoint an agent for service, service may be made by posting a copy in the office of the commissioner and filing a copy of it in the office of the lieutenant governor and by mailing a copy to the lessee's last known address;

(11) the applicable law of this state will be used in resolving questions of interpretation of the lease;

(12) the granting of the right-of-way lease is subject to the express condition that the exercise of the rights and privileges granted under the lease will not unduly interfere with the management, administration, or disposal by the state of the land affected by the lease, and that the lessee agrees and consents to the occupancy and use by the state, its grantees, permittees, or other lessees of any part of the right-of-way not actually occupied or required by the pipeline for the full and safe utilization of the pipeline, for necessary operations incident to land management, administration, or disposal;

(13) it will be liable to the state for damages or injury incurred by the state caused by the construction, operation or maintenance of the pipeline and it will indemnify the state for the liabilities or damages;

(14) it will procure and furnish liability and property damage insurance from a company licensed to do business in the state or furnish other security or undertaking upon the terms and conditions the commissioner considers necessary if the commissioner finds that the net assets of the lessee are insufficient to protect the public from damage for which the lessee may be liable arising out of the construction or operation of the pipeline.

(b) For a right-of-way lease granted under this chapter for an oil or natural gas pipeline valued at $1,000,000 or more to be valid and of legal effect, it must contain the terms required to be inserted under the provisions of §§ 110 — 140 of this chapter. An oil or natural gas pipeline right-of-way lease granted under this chapter that does not contain the required terms is null and void and without legal effect and does not vest any interest in state land or any authority in the carrier granted the lease.

(c) The commissioner may insert in any right-of-way lease other reasonable provisions and conditions that he determines the public interest requires.

(d) The lease will also contain terms and conditions that are reasonably necessary to obligate the lessee, to the extent reasonably practicable, to

(1) prevent conflicts with other existing uses of the land involving a superior public interest;

(2) protect state and private property interests;

(3) prevent any significant adverse environmental impact, including but not limited to the erosion of the surface of the land, and damage to fish and wildlife and their habitat;

(4) restore and revegetate during the term and at termination of the lease; and

(5) protect the interests of individuals living in the general area of the right-of-way who rely on the fish, wildlife, and biotic resources of the area for subsistence purposes.

(e) In the event the commissioner proposes to offer a lease or leases to two or more lessees for the same pipeline, the commissioner may include terms in the lease or leases which establish the limit of the obligations and liabilities of each lessee arising under this chapter or under the lease or leases.

(f) The commissioner may, at his discretion, include any or all of the terms set out in this section in leases of state land for products pipeline right-of-way purposes. (§ 1 ch 72 SLA 1972; am § 11 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.130. Right-of-way easements or leases acquired from others. (a) The lessee may, if the commissioner delegates the function to it, condemn, by declaration of taking, under AS 09.55.420 — 09.55.450, real property and acquire leases of or easements or rights-of-way on lands in the state required for right-of-way purposes for a pipeline subject to the lease on behalf of and as agent for the state in which title to or interest in the land shall vest.

(b) The lease shall contain a covenant that the land, right-of-way, or easement acquired under this section is or will form part of the land leased to the lessee. (§ 1 ch 72 SLA 1972; am § 12 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote subsection (a), deleting the paragraph designations and deleting the provisions of former paragraphs (1) and (2). The amendment also, in subsection (b), substituted "The lease shall contain a covenant" for "The lease covenant required by this section shall be accompanied by a provision" and deleted "carrier" following "lessee."

Quoted in Arco Pipeline Co. v. 3.60 Acres, More or Less, Sup. Ct. Op. No. 1177 (File No. 2419), 539 P.2d 64 (1975).

Sec. 38.35.140. Payment of rental and costs. (a) The lease price for a right-of-way lease shall be the annual fair market rental of the state lands included in the right-of-way based on the appraised fair market value of the land. The lease price is payable annually in advance on or before the anniversary of the lease. The appraised fair market rental value shall be adjusted periodically under the provisions of AS 38.05.015. Rental may not be charged for any land acquired by the lessee under § 130(b) of this chapter and conveyed without cost to the state.

(b) The lessee shall reimburse the state for all reasonable costs incurred in monitoring the construction of the pipeline on the right-of-way. (§ 1 ch 72 SLA 1972; am § 13 ch 3 FSSLA 1973)

Bob Stocker - due APUC

Sections from APUC

.05.141 - 211 P + D

221 - 281 P. Conv + Nec.

AG is legal counsel

Xerox 42.05.711 (d)

42.05.141 ~~(1)~~

42.05.171

191

201

HEA 42.05.221 (d) (1) - (5)

42.05.541

42.05.701 (2) (D)

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Sec. 42.05.141. General powers and duties of the commission. The Alaska Public Utilities Commission may

(1) regulate every public utility engaged or proposing to engage in such a business inside the state, except to the extent exempted by § 711 of this chapter and the powers of the commission shall be liberally construed to accomplish its stated purposes;

(2) investigate, upon complaint or upon its own motion, the rates, classifications, rules, regulations, practices, services and facilities of a public utility and hold hearings on them;

(3) make or require just, fair and reasonable rates, classifications, regulations, practices, services and facilities for a public utility;

(4) prescribe the system of accounts and regulate the service and safety of operations of a public utility;

(5) require a public utility to file reports and other information and data;

(6) appear personally or by counsel and represent the interests and welfare of the state in all matters and proceedings involving a public utility pending before an officer, department, board, commission or court of the state or of another state or the United States and to intervene in, protest, resist, or advocate the granting, denial or modification of any petition, application, complaint or other proceeding;

(7) examine witnesses and offer evidence in any proceeding affecting the state and initiate or participate in judicial proceedings to the extent necessary to protect and promote the interests of the state. (§ 6 ch 113 SLA 1970; am § 1 ch 33 SLA 1971)

The general powers and duties of the Public Utilities Commission are set forth in this section. Greater Anchorage Area Borough v. City of Anchorage, Sup. Ct. Op. No. 856 (File No. 1569), 504 P.2d 1027 (1972).

The essence of the administrative power conferred upon the Public Utilities Commission is regulatory; the commission is empowered to set rates, promulgate regulations, collect information, process complaints against utilities and the like. Greater Anchorage Area Borough v. City of Anchorage, Sup. Ct. Op. No. 856 (File No. 1569), 504 P.2d 1027 (1972).

The statutory framework does not grant unlimited adjudicatory authority to the Public Utilities Commission. Greater Anchorage Area Borough v. City of Anchorage, Sup. Ct. Op. No. 856 (File No. 1569), 504 P.2d 1027 (1972).

This chapter simply does not contemplate the establishment of an administrative body with the authority to adjudicate disputes over the authority of boroughs to control construction along their rights of way. Greater Anchorage Area Borough v. City of Anchorage, Sup. Ct. Op. No. 856 (File No. 1569), 504 P.2d 1027 (1972).

The Public Utilities Commission is not empowered to decide disputes between municipalities over the control of construction activities within rights of way belonging to one of the disputants. Greater Anchorage Area Borough v. City of Anchorage, Sup. Ct. Op. No. 856 (File No. 1569), 504 P.2d 1027 (1972).

There is no "right" to have the commission act. Jager v. State, Sup. Ct. Op. No. 1161 (File No. 2057), 537 P.2d 1100 (1975).

The matter of rate discrimination and investigation is such that the commission must be free to weigh the charges and data presented and the costs to the public and the utility, against which a complaint has been brought, to determine whether further proceedings are in the public interest. Jager v. State, Sup. Ct. Op. No. 1161 (File No. 2057), 537 P.2d 1100 (1975).

(b) The Administrative Procedure Act applies to regulations adopted by the commission. (§ 6 ch 113 SLA 1970)

Sec. 42.05.171. Formal hearings. A formal hearing which the commission has power to hold may be held by or before two or more commissioners designated for the purpose by the commission. The testimony and evidence in a formal hearing may be taken by the commissioners to whom the hearing has been assigned. A commissioner who has not heard the testimony, including the argument, may not participate in making a decision of the commission. In determining the place of a hearing the commission shall give preference to holding the hearing at a place most convenient for those interested in the subject of the hearing. (§ 6 ch 113 SLA 1970)

Sec. 42.05.181. Final orders of the commission. No final order of the commission compelling affirmative action, denying a right or privilege, or granting a right or privilege over protest of the public utility or any party of record may be entered without giving the interested party reasonable notice and an opportunity to be heard. (§ 6 ch 113 SLA 1970)

Sec. 42.05.191. Format of orders. Every formal order of the commission shall be based upon the facts of record. Every order entered pursuant to a hearing shall state the commission's findings, the basis of its findings and conclusions, together with its decision. These orders shall be entered of record and a copy of them shall be served on all parties of record in the proceeding. (§ 6 ch 113 SLA 1970)

Sec. 42.05.201. Publication of reports, orders, decisions and regulations. All reports, orders, decisions and regulations of the commission shall be in writing. The commission shall apprise all affected utilities and interested parties of these reports, orders, decisions, and regulations as they are issued and adopted, and, when appropriate to do so, shall publish them in a manner that will reasonably inform the public or the affected consumers of any public utility service. The commission may set charges for costs of printing or reproducing and furnishing copies of its reports, orders, decisions and regulations. The publication requirement, as it pertains to regulations, does not supersede the requirements of the Administrative Procedure Act (AS 44.62). (§ 6 ch 113 SLA 1970)

Sec. 42.05.211. Annual report. The commission shall publish an annual report reviewing its work and submit it to the legislature by February 15 of each year. The report shall contain information and data which bear a significant relationship to the development and regulation of public utility services in the state and include an outline of the commission's program for the development and regulation of public utility services in the forthcoming year. (§ 6 ch 113 SLA 1970)

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Article 3. Certificate of Public Convenience and Necessity.

Section
221. Certificates required
231. Application
241. Conditions of issuance
251. Use of streets in cities and boroughs
261. Discontinuance, suspension or abandonment of certificated service
271. Modification, suspension or revocation of certificates
281. Transfer of certificate

Repeal of former article. — Section 5, ch. 113, SLA 1970, repealed former Article 3, entitled "Valuation of Public Utility Properties." The former article consisted of §§ 42.05.250 — 42.05.280 and derived from ch. 199, SLA 1959.

HEA

Sec. 42.05.221. Certificates required. (a) No public utility may operate and receive compensation for providing a commodity or service after January 1, 1971 without first having obtained from the commission under this chapter a certificate declaring that public convenience and necessity require or will require the service. Where a public utility provides more than one type of utility service, a separate certificate of convenience and necessity is required for each type. A certificate shall describe the nature and extent of the authority granted in it, including, as appropriate for the services involved, a description of the authorized area and scope of operations of the public utility.

(b) All certificates of convenience and necessity issued to a public utility before July 1, 1970 remain in effect but they are subject to modification where there are areas of conflict with public utilities that have not previously been required to have a certificate or where there is a substantial change in circumstances.

(c) A certificate shall be issued to a public utility which was not required to have one before July 1, 1970, and which is required to have one after that date, if it appears to the commission that the utility was actually operating in good faith on that date. Such a certificate is subject to modification where there are areas of conflict with other public utilities or where there has been a substantial change in circumstances.

(d) In an area where the commission determines that two or more public utilities are competing to furnish identical utility service and that this competition is not in the public interest, the commission shall take appropriate action to eliminate the competition and any undesirable duplication of facilities. This appropriate action may include, but is not limited to, ordering the competing utilities to enter into a contract which, among other things would:

(1) delineate the service area boundaries of each in those areas of competition;

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(2) eliminate existing duplication and paralleling to the fullest reasonable extent;

(3) preclude future duplication and paralleling;

(4) provide for the exchange of customers and facilities for the purposes of providing better public service and of eliminating duplication and paralleling; and

(5) provide such other mutually equitable arrangements as would be in the public interest.

(e) The commission may employ professional consultants to assist it in administering the provisions of this section and may apportion the expenses relating to this administration among the competing utilities involved.

(f) A certificate shall be issued by the Public Utilities Commission to a public utility engaged in garbage, refuse, trash or other waste material collection and disposal which was not required to have one before January 1, 1973, and which is required to have one after that date, if the public utility was previously operating under the authority of a permanent permit granted by the Alaska Transportation Commission. The certificate, however, shall exclude all areas within the limits of an incorporated city except a unified city/borough municipality as they existed on January 1, 1973 even though the area was included in the permit issued by the Alaska Transportation Commission. In unified city/borough municipalities, the certificate shall exclude only such areas as were actually served by the municipalities on January 1, 1973. Any area annexed after January 1, 1973, shall not be excluded from a carrier's certificate effective at the time of annexation, and shall be governed by the general provisions of this section. A political subdivision of the state may not provide for a garbage, refuse, trash or other waste material collection and disposal service in any area to the extent it lies within an area granted to a garbage or refuse carrier by a certificate issued by the commission to the carrier until it has purchased the certificate, equipment and facilities of the carrier or that portion of the certificate, facilities and equipment which would be affected, at fair market value. Section 711(b) of this chapter notwithstanding, this subsection shall not be construed to have the effect of bringing public utilities owned and operated by a political subdivision of the state within the jurisdiction of the Alaska Public Utilities Commission. (§ 6 ch 113 SLA 1970; am § 1 ch 76 SLA 1973)

Effect of amendment. — The 1973 amendment added subsection (f).

A certificate of public convenience and necessity is a property right and as such entitled to protection. Homer Elec. Ass'n v. City of Kenai, Sup. Ct. Op. No. 390 (File No. 675), 423 P.2d 285 (1967).

Certificate does not grant monopoly. — A certificate of public convenience and necessity to a public utility by the Alaska Public Service Commission is not an exclusive, or monopoly, grant to furnish electrical energy within the corporate limits of a city. Chugach Elec. Ass'n v. City of Anchorage, Sup. Ct. Op. No. 407 (File Nos. 705, 706), 426 P.2d 1001 (1967).

A public utility's certificate did not grant to it the exclusive right to furnish electrical energy within the corporate limits of a city. Homer Elec. Ass'n v. City of Kenai, Sup. Ct.

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would have incurred if it furnished the service or property with its own personnel and capital. (§ 6 ch 113 SLA 1970)

Am. Jur. and C.J.S. references. — 43 Am. Jur., Public Utilities and Services, §§ 196, 216 to 223.

73 C.J.S. Public Utilities § 46 et seq.

Sec. 42.05.521. Impaired capital. When the commission finds that the capital of a public utility corporation is impaired, or might become impaired, it may, after investigation and hearing, issue an order directing the public utility to cease paying dividends on its common stock until the impairment has been removed. (§ 6 ch 113 SLA 1970)

Sec. 42.05.531. Distribution of surplus and profits. The surplus and profits of public utilities shall be distributed in accordance with the bylaws or ordinances controlling the utility. (§ 6 ch 113 SLA 1970)

Article 8. Judicial Review, Penalties and Enforcement.

Section
541. Effect of regulations
551. Review and enforcement
561. Injunctive and monetary sanctions
571. Civil penalties
581. Each violation a separate offense
601. Actions to recover penalties; disposition
611. Penalties cumulative
621. Joinder of actions

Repeal of former article. — Section 5, ch. 113, SLA 1970, repealed former Article 8, entitled "Municipal and Other Publicly Owned Utilities." The former article consisted of §§ 42.05.620 — 42.05.630 and derived from ch. 199, SLA 1959.

Sec. 42.05.541. Effect of regulations. Regulations adopted and issued by the commission in accordance with this chapter have the effect of law. (§ 6 ch 113 SLA 1970)

Sec. 42.05.551. Review and enforcement. (a) All final orders of the commission are subject to judicial review in accordance with AS 44.62.560 — 44.62.570 of the Administrative Procedure Act.

(b) If an appeal is not taken from a final order of the commission, the commission may apply to the superior court for enforcement of this chapter, the regulations adopted under it and the orders of the commission. The court shall enforce the order by injunction or other process. (§ 6 ch 113 SLA 1970)

Orders of commission expressly made subject to Administrative Procedure Act. — Subsection (a) of this section expressly makes orders of the Public Utilities Commission subject to the provisions of the Alaska Administrative Procedure Act (AS 44.62). Greater Anchorage Area Borough v. City of Anchorage, Sup. Ct. Op. No. 856 (File No. 1569), 504 P.2d 1027 (1972).

AS 44.62.570 is made applicable to review of final orders of the Public Utilities Commission by this section. Jager v. State,

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Article 10. General Provisions.

Section
701. Definitions
711. Exemptions
721. Short title

Sec. 42.05.701. Definitions. In this chapter

(1) "commission" means the Alaska Public Utilities Commission;

(2) "public utility" or "utility" includes every corporation (whether public, cooperative, or otherwise), company, individual, or association of individuals, their lessees, trustees, or receivers appointed by a court, that owns, operates, manages or controls any plant, pipeline or system for

(A) furnishing, by generation, transmission or distribution, electrical service to the public for compensation;

(B) furnishing telecommunications service to the public for compensation;

(C) furnishing water, steam or sewer service to the public for compensation;

(D) furnishing by transmission or distribution of natural or manufactured gas to the Alaska public for compensation;

(E) furnishing for distribution or by distribution petroleum or petroleum products to the Alaska public for compensation when the consumer has no alternative in his choice of supplier of a comparable product and service at an equal or lesser price;

(F) furnishing collection and disposal service of garbage, refuse, trash or other waste material.

(3) "service" means (unless the context indicates otherwise) every commodity, product, use, facility, convenience or other form of service which is offered for and provided by a public utility for the convenience and necessity of the public;

(4) "rate" includes each rate, toll, fare, rental, charge, or other form of compensation demanded, observed, charged or collected by a public utility for its services;

(5) "public" or "general public" means

(A) any group of 10 or more customers that purchase the service or commodity furnished by a public utility as defined in (2) of this section; and

(B) any utility purchasing the product or service or paying for the transmission of electric energy, natural or manufactured gas, or petroleum products which are re-sold to a group included in (A) of this paragraph or which are used to produce the service or commodity sold to the public by the utility.

(6) "affiliated interest" includes:

(A) a person owning or holding directly or indirectly five per cent or more of the voting securities of a public utility engaged in intrastate business in this state;

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(B) a person, other than those specified in (A) of this paragraph, in a chain of successive ownership of five per cent or more of voting securities, the chain beginning with the holder of the voting securities of such public utility;

(C) a corporation five per cent or more of whose voting securities are owned by a person owning five per cent or more of the voting securities of the public utility or by a person in such a chain of successive ownership of five per cent or more of voting securities;

(D) a corporation five per cent or more of whose voting securities are owned or held by a public utility;

(E) a person with whom the public utility has a management or service contract;

(F) a person who is an officer or director of such a public utility or of a corporation in a chain of successive ownership of five per cent or more of voting securities;

(G) a corporation which has one or more officers or directors in common with a public utility;

(H) a person or corporation who or which the commission determines as a matter of fact, after investigation and hearing, actually is exercising such substantial influence over the policies and actions of a utility in conjunction with one or more other corporations or persons with whom they are related by ownership or blood, or by action in concert, that together they are affiliated with the utility within the meaning of this section even though none of them alone is so affiliated; or

(I) a person or corporation who or which the commission determines as a matter of fact after investigation and hearing actually is exercising substantial influence over the policies and actions of a utility even though such influence is not based upon stockholdings, stockholders, officers or directors to the extent specified in this section;

(7) "tariff" means a rate, charge, toll, rule or regulation of a utility relating to services furnished by the utility to the general public for compensation and every map, page, adoption notice, instrument or other document filed with the commission setting out the terms and conditions under which utility services are offered to the public and instruments of concurrence and all other documents and data setting out the terms of a utility's business relations with another utility insofar as they affect the general public either directly or indirectly;

(8) "telecommunications" means the transmission and reception of messages, impressions, pictures and signals by means of electricity, electromagnetic waves and any other kind of energy, force variations or impulses whether conveyed by cable, wire, radiated through space, or transmitted through other media within a specified area or between designated points. (§ 6 ch 113 SLA 1970; am § 2 ch 36 SLA 1971; am § 2 ch 76 SLA 1973)

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Effect of amendment. — The 1973 amendment added subdivision (2)(F).

Editor's note. — Section 1, ch. 36, SLA 1971, provides: "Purpose. It is the finding of the legislature that it is necessary to avoid unnecessary regulatory procedures over petroleum fuel dealers delivering to trailer courts and apartment buildings having local pipe distribution systems for heating fuel, and whose owners or residents have a choice of suppliers."

Legislative committee report. — For report on ch. 113, SLA 1970 (SCSCSHB 2[illegible] am S), see 1969 House Journal, p. 549, and Supplement No. 4 (4/9/69).

Rural Electrification Act does not curtail state regulatory powers. — Since the Rural Electrification Act is primarily a financing measure rather than a regulatory measure, it was in no way intended to curtail otherwise legitimate exercises of state regulatory powers. 1964 Op. Att'y Gen., No. 1.

REA cooperatives are subject to regulation by the Public Service Commission. 1964 Op. Att'y Gen., No. 1.

As subdivision (2) specifically states that intention. — Whether a state may regulate electrical cooperatives as public utilities depends primarily on the language of the relevant state statutes. Where, as in the case of subdivision (2) of this section, the legislature has specifically stated its intention that cooperatives, as well as the more usual types of public utilities are to be covered, this is controlling. 1964 Op. Att'y Gen., No. 1.

And it is unnecessary to look to other criteria. — It is not necessary to look to criteria which courts normally use to determine whether a particular REA cooperative is a public utility (e.g., limitation of service to members) where the statute specifically covers cooperatives. 1964 Op. Att'y Gen., No. 1.

Am. Jur., ALR and C.J.S. references. — 43 Am. Jur., Public Utilities and Services, § 1 et seq.

What are "public utilities within provisions relating to municipal purchase, construction or repair of public utility, 9 ALR 1033; 35 ALR 592.

Conclusiveness of charter as regards character of corporation as a public utility corporation, 119 ALR 1019.

73 C.J.S. Public Utilities §§ 1 to 3.

Sec. 42.05.711. Exemptions. (a) The provisions of this chapter do not apply to a person who furnishes water, gas or petroleum or petroleum products by tank, wagon, or similar conveyance, unless the person is thereby supplying water, gas, petroleum or petroleum products to a public utility in which he has an "affiliated interest."

(b) Public utilities owned and operated by a political subdivision of the state and none of whose utilities, excepting the furnishing of collection and disposal service of garbage, refuse, trash or other waste material, is in competition with any other utility, are exempt from the provisions of this chapter, other than the provisions of §§ 221 — 281 of this chapter, unless the owner and operator elects to be subject to all provisions of this chapter. Notwithstanding any other provisions of this chapter, municipalities providing collection and disposal service of garbage, refuse, trash or other waste material within their corporate boundaries are not subject to regulation by the Alaska Public Utilities Commission unless the municipality elects to be subject to the provisions of this chapter.

(c) The ownership in whole or part, of the corporate stock of a public utility does not make the owner a public utility.

(d) The commission, on a finding that no legitimate public interest will be served, may exempt a utility from all or any portion of this chapter.

(e) Notwithstanding any other provisions of this chapter, any electric or telephone utility that does not gross $25,000 annually is exempt from

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regulation hereunder unless 25 per cent of the subscribers petition the commission for regulation. (§ 6 ch 113 SLA 1970; am § 3 ch 76 SLA 1973)

Effect of amendment. — The 1973 amendment inserted the language beginning "excepting" and ending "waste material" in the first sentence of subsection (b), substituted "the" for "such an" in that sentence, and added the second sentence of that subsection.

Sec. 42.05.721. Short title. This chapter may be cited as the Alaska Public Utilities Commission Act. (§ 6 ch 113 SLA 1970)

Editor's note.—Section 7, ch. 113, SLA 1970, provides: "All litigations, hearings, investigations, and other proceedings whatsoever, pending under any law repealed by this Act, shall continue and remain in full force and effect, and may be continued and completed under the provisions of this act. All certificates, orders, rules, regulations, or tariffs, made, issued, or filed under any law repealed by this Act, and in full force and effect on July 1, 1970, shall remain in full force and effect for the term issued, or until revoked, vacated, or modified under the provisions of this Act. All existing contracts and obligations of the commission, entered into or created under any law repealed by this Act, and in force and effect on July 1, 1970, shall remain in full force and effect and shall continue to be performed by the commission. The existing rates, charges, tariffs, rules, regulations, service and service area of the municipally owned utility shall continue and remain in full force and effect unless otherwise ordered by the commission under the provisions of this Act."

Legislative committee report. — For report on ch. 113, SLA 1970 (SCSCSHB 202 am S), see 1969 House Journal, p. 549, and Supplement No. 4 (4/9/69).

Chapter 06. Alaska Pipeline Commission Act.

Article
1. Declaration of Policy (§ 42.06.010)
2. Establishment of Alaska Pipeline Commission (§§ 42.06.020 — 42.06.130)
3. Powers and Duties of Commission (§ 42.06.140 — 42.06.640)

Legislative committee report. — For report on ch. 139, SLA 1972 (FCCS HCS CSSB 314), see 1972 Senate Journal, p. 1072; 1972 House Journal, p. 1420.

Article 1. Declaration of Policy.

Section
10. Legislative declaration of policy

Sec. 42.06.010. Legislative declaration of policy. The transportation of oil or gas by pipeline in the state is a business involved with the public interest. It is the purpose of this chapter to

(1) promote and oversee the development of an oil and gas pipeline transportation system in the state properly adapted to the present and future needs of the domestic commerce of the state and of the interstate and foreign commerce of the United States;

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U-75-68(3)

STATE OF ALASKA

THE ALASKA PUBLIC UTILITIES COMMISSION

Before Commissioners: Gordon J. Zerbetz, Chairman
Marvin R. Weatherly
Carolyn S. Guess
Susan M. Knowles
Stuart C. Hall

In the Matter of the Filing of a Tariff Revision, Designated as TA12-4, by ALASKA GAS AND SERVICE COMPANY to Adopt Purchased Gas and Tax Adjustment Clauses

U-75-68

ERRATA NOTICE

ORDER NO. 3

ORDER MODIFYING PURCHASED GAS COST AND TAX FLOW THROUGH CLAUSES AND ACCEPTING MODIFIED CLAUSES

(Issued December 17, 1975)

Page 14, line 1 of Ordering Paragraph No. 3: Change "Royalty Tax" to "Royalty Gas"

DATED AND EFFECTIVE at Anchorage, Alaska, this 1st day of November 1976.

BY DIRECTION OF THE COMMISSION

(S E A L)



STATE OF ALASKA

THE ALASKA PUBLIC UTILITIES COMMISSION

Before Commissioners: Gordon J. Zerbetz, Chairman
B. Richard Edwards
Marvin R. Weatherly
Carolyn S. Guess (not participating)
Susan M. Knowles

In the Matter of the Filing of a Tariff Revision, Designated as TA12-4, by ALASKA GAS AND SERVICE COMPANY to Adopt Purchased Gas and Tax Adjustment Clauses	U-75-68 ORDER NO. 3

ORDER MODIFYING PURCHASED GAS COST AND TAX FLOW THROUGH CLAUSES AND ACCEPTING MODIFIED CLAUSES

On July 31, 1975, ALASKA GAS AND SERVICE COMPANY (AGAS), a division of Alaska Interstate Company, filed a tariff revision to reinstate in its natural gas utility tariff its tariff rules Nos. 708 and 709. These sections would allow AGAS to flow through to its customers, by means of a billing surcharge, any increase in its wellhead cost of gas above 41.5¢ per MCF occurring after July 1, 1975, and any new or increased tax or excise imposed by Federal, State, Borough, Municipal or other local taxing authority upon the production, transmission, or sale of gas, or levies of special taxes, license fees, or street or right-of-way levies or fees, above the amounts established on January 1, 1975.

Order No. 1 in this proceeding suspended the tariff revision until March 1, 1976. In Order No. 1 the Commission also established a hearing date of October 30, 1975. AGAS was to bear the burden of proof that the tariff revision requested was reasonable and proper in all respects.

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On October 16, 1975, the MUNICIPALITY OF ANCHORAGE d/b/a MUNICIPAL LIGHT & POWER (ML&P) petitioned the Commission for leave to intervene in the above-captioned proceedings. Order No. 2 in this proceeding, issued on October 27, 1975, allowed ML&P to intervene in this docket.

The tariff revision was noticed to the public by notice dated August 6, 1975. The public hearing of this matter was also noticed to the public by notice placed in the Anchorage Daily Times on October 29, 1975. Several objections to the flow through provisions of AGAS were received by the Commission.

AGAS requested a purchased gas cost adjustment clause and tax adjustment clause to read as follows:

> 708 Purchased Gas Cost Adjustment - Company's rates as of July 1, 1975, are based on a wellhead cost of gas of 22.0¢ per MCF plus 19.5¢ per MCF as a deliverability charge, for a total of 41.5¢ per MCF. In the event this cost is increased or decreased from said amount after July 1, 1975, then the Company may, after appropriate notice to the Alaska Public Utilities Commission as required by AS 42.05.411, place into effect a like increase or decrease in the rates theretofore in effect. Such adjustment shall be pro-rated on bills rendered subsequent to the effective date of the increase or decrease, provided, however, that this Section 708 shall not be implemented by the Company to reflect any negotiated upward re-pricing of any gas reserves or deliverability previously committed to the Company. It is understood that certain escalations of wellhead gas cost are contemplated in the Company's gas purchase contract (amendment dated De-

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cember 18, 1974) and that these escalations will be implemented by this Section 708. It is also understood that the Company may by negotiation acquire additional deliverability and that the cost of gas obtained pursuant to such negotiations will be subject to the implementation of this Section 708.

Implementation of this Section 708 shall not be construed as a justification for perpetuating any particular rate of return by the Company. It shall not be deemed to prevent or impede the Alaska Public Utilities Commission from requiring the Company to carry the burden of proof as to the appropriateness of any of the Company's rate schedules or its rate of return at any time upon reasonable notice by the Commission and for reasonable cause given by the Commission with such notice.

709 Tax Adjustment - Whenever any Federal, State, Borough, Municipal or other local taxing authority imposes any new or increased specific tax or excise upon the production, transmission or sale of gas or levies special taxes, license fees, or street or right of way rentals or fees, above the amount(s) payable on January 1, 1975, any of which are payable by or reimbursable by the Company, Company may, after appropriate notice to the Alaska Public Utilities Commission as required by AS 42.05.411, recover a proportionate share of such increase from the customers served within the tax unit or units levying such tax, excise or special charge based on the proportionate volume of gas used by

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such customers, as a line item surcharge on company's billing for service rendered.

If the tax is thus applicable to all customers of the Company rather than to only a portion, then the Company's rates and contracts will be accordingly revised rather than to institute the line item surcharge. Federal or state income taxes or surtax on such income taxes shall not be deemed to be a "tax" for the purpose of implementing this Section 709.

For reasons stated below it is the Commission's opinion that these clauses should read as follows:

Purchased Gas Cost Adjustment - The gas supply contracts existing on December 1, 1975, contain escalation clauses which result in periodic increases or decreases in the cost of purchased gas. Any increase in the cost of purchased gas to the Company under the escalation clauses that the Company becomes responsible for after July 1, 1976, may be passed on to the customers of the Company. Such an increase may be reflected in the rates paid by the customers for gas used by the customer after the date the Company is responsible for paying the increase. The increase, however, may not be charged to the customers of the Company unless the Company meets the conditions specified in Order No. 3 in Docket U-75-68. The Company may not flow through to its customers any increases in the cost of gas resulting from alterations, changes, or amendments of any part of the escalation clauses existing on December 1, 1975. The Company also may not flow through to its customers any other increase in the cost of gas except as speci-

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fied in this Section and the Royalty Gas Section of this tariff. The increases flowed through to the customers pursuant to this section may not exceed 5¢/MCF per calendar year.

In the event the price which the Company must pay to purchase gas to serve the Company's customers is decreased the Company shall decrease its rates to its customers to fully reflect the entire decrease in the purchased gas cost.

Royalty Gas - The cost of gas purchased from the State is greater than the cost of gas purchased from other suppliers. The gas purchased from the State must be taken by the Company as produced. The Company must therefore distribute this gas to its customers when taken and it must be sold at a higher rate than the gas it now purchases from other suppliers. In order to insure a proper price of gas as a result of the commingling of the higher priced State gas and the lower priced gas from other suppliers the Company shall, month to month, increase or decrease the bills of customers to reflect the average cost per MCF of gas on an MCF basis which shall be computed as the product of the volume of gas purchased from the State each month multiplied by the price of that gas, plus the product of the volume of gas purchased from other suppliers during the month multiplied by the cost of this gas, and the sum of the products thus computed divided by the total volume of gas purchased. The flow through increases or decreases pursuant to this section of the tariff are subject to

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the conditions set forth in Order No. 3 of Docket U-75-68.

Reserve Tax - The reserve tax payable by the gas company as a result of the enactment of 159 SLA 1975 may be charged to the customers of the Company as a surcharge to be separately specified and identified on the bills of the customers. Only the portion of the reserve tax that is not offset by the severance tax in the year the reserve tax is due and owing may be surcharged to the customers. Any further credits to the reserve tax for payments of severance taxes shall be treated as a decrease in the severance tax adjustment allowed by the Severance Tax Section of this tariff. The reserve tax adjustment is subject to the conditions set forth in Order No. 3 of Docket U-75-68.

Severance Tax - In the event the severance tax on the gas necessary for the Company to serve its customers is increased above the amount payable on July 1, 1976, the Company may, in accordance with Order No. 3 in APUC Docket U-75-68 increase correspondingly the rates charged to the Company's customers to reflect the increase in severance taxes. The rates to the customers may be increased in accordance with the amount of gas consumed by the customers. In the event the severance tax charged by the State on the gas necessary to serve the Company's customers decreases the Company shall decrease its rates to its customers to fully reflect the entire decrease in the severance taxes. The rates charged its customers shall also be decreased

AGO 801507

to reflect any portion of the severance tax that is decreased by the State as an offset to the reserve taxes paid by the Company pursuant to 159 SLA 1975.

As can be noted, there are several differences between the flow through provisions proposed by the company and those acceptable to the Commission. In the first place, the Commission has made more specific the type of cost increases and taxes which will be allowed to be flowed through to the customers of AGAS. The Commission has specifically allowed flow through of severance taxes, periodic price escalations pursuant to clauses of contracts existing on December 1, 1975, royalty gas purchases from the State, and the reserve tax enacted by the 1975 Alaska legislature. The provisions proposed by the company were so broad that nearly all increases in any tax or cost of purchased gas could be flowed through. The Commission is reluctant to again find itself in the situation which occurred this past year when AGAS proposed to flow through to its customers pursuant to a similar provision as now proposed by AGAS the deliverability charge of 19.5¢ per MCF.

From the testimony at the hearing it is apparent that at least one escalation clause in a supplier's contract with AGAS is dependent upon changes in the wholesale price index of November of each year. Apparently the price increase per MCF would go into effect on January 1 of the following year. This appears to allow approximately 30 days in which to properly prepare the information that the Commission would like to review and notice before the increase becomes effective. The conditions set forth in this order

AGO 801508

will be tailored as much as possible to enable the gas cost increases based on the wholesale price index to be flowed through in a timely manner.

Where a flow through will not result in AGAS maintaining or receiving more than a reasonable rate of return on its investment it is the opinion of this Commission that the flow through should be permitted. The basic reason for flow through provisions is to insure that a short term windfall does not accrue to the customers of AGAS in rates which do not properly reflect the revenue requirements of AGAS. Such a windfall would result from short term regulatory lag. When designing flow through clauses or allowing the flow throughs pursuant to the clauses the Commission must insure that windfall profits do not accrue to AGAS. Each of the flow through clauses acceptable to the Commission should be applied by AGAS with this in mind. Conservative applications of these clauses should be the norm for AGAS. If the Commission determines that the flow through clauses set forth above in this order including the royalty gas clause are being applied to maintain or receive more than a reasonable rate of return or are otherwise being abused the Commission will commence an investigation to repeal these clauses and order appropriate refunds where applicable.

N/A since it talks about return on investment. No investment is involved

Royalty Gas

The evidence in this proceeding clearly demonstrates that if AGAS is able to purchase royalty gas from the State of Alaska it will be necessary that AGAS take the gas as it is produced and that the price of this royalty gas will be somewhat higher than the price of gas from other gas

AGO 801509

supplies now committed to AGAS. The volume of gas from the State will not meet the entire demand on the system which results in commingling of high and low priced gas. This commingling raises several problems. The initial problem is a month to month change in rates to the consumers of AGAS. The month to month billings would vary directly in accordance with the royalty gas portion of the total gas volume consumed by the customers of AGAS. A higher proportion of royalty gas consumed would result in an increased average cost of gas. In order to prevent a windfall for either AGAS or the customers of AGAS that would result by setting a constant average price, it is the Commission's opinion that the royalty gas may be commingled with the cheaper gas and that the month to month rates of customers of AGAS may vary in accordance with the amount of royalty gas distributed to the customers. Another problem raised with the royalty gas variation involves the conditions under which the royalty gas flow through clause may be used. It is apparent to the Commission that monthly filings of comparative balance sheets, operating expense statements, rate of return calculations and rate base calculations is not practical for the implementation of this clause. It is the Commission's opinion, however, that a report should be filed by AGAS in a form acceptable to the staff of the Commission, that would allow the staff of the Commission to audit the fluctuation of the rates charged for gas to the customers of AGAS. These reports will be due on January 15, April 15, July 15 and October 15 of each year. The information in the report should at least show the total volume of gas consumed for each of the months involved in the report, the volume of

AGO 801510

royalty gas purchased for each month, the price of the royalty gas at the point of purchase by AGAS, and the price and volume of the gas purchased by AGAS from other suppliers.

The method which should be used by AGAS to determine its average cost of gas per MCF is to multiply the amount of State royalty gas purchased in a month times the price of the State royalty gas and add to that product the product of the price and volume of gas purchased from other suppliers in the same month. The sum of the two products should then be divided by the total amount of gas purchased in the month to arrive at the average cost of gas per MCF. It is apparent to the Commission that by using this formula the additional cost of gas per MCF that the customers of AGAS will pay as a result of the commingling of royalty gas with other gas will fall generally in the range of 2 to 5¢ per MCF per month.

It is the Commission's opinion that it is imperative for AGAS to obtain additional reserves and gas supply to serve its customers. If the royalty clause is not used to reflect an average cost of gas on or before August 1, 1976, this Commission will commence an investigation to determine the reasons for the non-use and whether the clause should be deleted from the tariff of AGAS.

RESERVE TAX

The evidence in this proceeding shows that the gas company may become responsible for the payment to its suppliers of gas of the reserve tax that its suppliers are required to pay the State of Alaska pursuant to 159 SLA 1975. It is the opinion of the Commission that this tax should be treated as an expense of the utility recoupable

AGO 801511

through its rates and charges. It appears to the Commission that 159 SLA 1975 provides for payments of the reserve tax to be made in 1976 and 1977. The amount of severance tax due the State in 1976 and 1977 will be deducted from the amount of reserve tax due the State. Furthermore, a certain portion of the severance tax due the State each year after 1977 will be credited against the paid-in reserve tax. Consequently, it is the Commission's opinion that only that portion of the reserve tax which is not offset by the severance tax in the years 1976 and 1977 should be flowed through to the customers of AGAS. Additionally the savings in severance tax payments subsequent to 1977 should result in a reduction of the severance tax which the customers of AGAS are required to pay through their monthly gas bills.

It is apparent to the Commission that the flow through of the reserve tax should be subject to such conditions as would permit the Commission to review the amount of flow through, the amount of severance tax set off against the reserve tax, the price increase per MCF, the projected amount to be collected, the refund procedure in the event more than the amount of tax due is collected and whether the tax will be collected on a one payment basis or as a monthly increase on customers' bills. The reporting of this information shall be in a form satisfactory to the staff of the Alaska Public Utilities Commission and contain at least the information set forth above. This report shall be filed with the Commission on January 15, April 15, July 15 and October 15 of 1976 and 1977 and a final report on January 15, 1978. Each report shall cover the immediate past three month period. Furthermore, it is the Commission's opinion

AGO 801512

that subsequent to the filing of the information AGAS should be allowed to collect or continue to collect the reserve tax unless the Commission within thirty days after the filing of the information orders an investigation into the flow through of this tax.

PURCHASED GAS COST ADJUSTMENT CLAUSE AND SEVERANCE TAX CLAUSE

It is apparent to the Commission from the evidence in this record that approximately 50% of the operating expense of AGAS involves the purchase of gas to be distributed to its customers. It is also apparent to the Commission that where the escalation clause involves the wholesale price index the amount of price increase in the cost of purchased gas could vary from year to year. The other price escalation clauses require increases in 1981 and 1986 and yearly thereafter.

It is the opinion of the Commission that these increases, subject to the conditions set forth below, should be allowed to be flowed through to the customers of AGAS.

The conditions to which a purchased gas cost adjustment clause and severance tax adjustment clause should be subject were previously outlined by this Commission in Order No. 6 in Docket U-74-115 regarding flow-through provisions similar to those now proposed by AGAS. It is apparent to the Commission that prior to using a purchased gas cost adjustment clause or severance tax adjustment clause AGAS should be required to file all the materials set forth in 3 AAC 48.275(a). This information includes comparative balance sheet statements, operating expense statements, rate of return calculations, and rate base calculations. This information should be filed at least 45 days before the

AGO 801513

proposed effective date of the flow through of the increase in the cost of purchased gas or severance taxes. The filing of this information will allow the Commission and staff to completely review the effect of the flow through and accommodate AGAS on its wholesale price index escalation clauses. If the Commission is of the opinion after reviewing the filed information that a rate case should be filed by AGAS, the Commission could then order AGAS to prepare and file a revenue requirement study. If such a revenue requirement study was ordered by the Commission, the study would be part of the burden of proof of AGAS to support its rates and charges to its customers. If the Commission required AGAS to support its rates based on its revenue requirements, the purchased gas cost or severance tax increase would be treated as a normal operating expense.

To assure that regulatory lag does not adversely effect AGAS if the Commission orders the rate investigation, the flow-through of the increased cost for purchased gas or severance taxes would be allowed to go into effect any time after the end of the 45-day notice period provided by AS 42.05.411(a). However, if a revenue requirement study and rate case filing are required by the Commission before the effective date of the flow-through, any portion of the flow-through paid by the customers of AGAS above the amount determined by the Commission to be reasonable in the rate investigation would be required to be refunded by AGAS to its customers.

As mentioned in Order No. 6 in Docket U-74-115, this procedure is similar to the procedures relating to fuel cost rate adjustment clauses which this Commission has

AGO 801514

allowed for several electric utilities. It is the Commission's opinion that the above restrictions and conditions on any type of flow-through clause are clearly reasonable and necessary to insure that the public is not charged a rate above the rate necessary for the company to receive a reasonable rate of return on its investment. These conditions and restrictions have proved the electric utility fuel cost rate adjustment clauses to be a workable and practical solution to increased costs of fuel.

As noted in the purchased gas cost adjustment and severance tax clauses these flow through provisions may only be used for price escalations after July 1, 1976. AGAS has recently filed a rate case with this Commission that should incorporate in AGAS's revenue requirements each of the price escalations up to July 1, 1976, for which AGAS is responsible.

ORDER

THE COMMISSION FURTHER ORDERS:

1. The flow through clauses, Sections 708 and 709, filed by Alaska Gas and Service Company are unacceptable to the Commission and therefore are disapproved.

2. The flow through clauses acceptable to the Commission are set forth in this Order on Pages 4, 5, 6 and 7 under the headings of Purchased Gas Cost Adjustment, Royalty Gas, Reserve Tax and Severance Tax.

3. The Royalty Gas flow through provision is subject to the condition that a report be filed by Alaska Gas and Service Company on January 15, April 15, July 15, and October 15 of each year setting forth as a minimum the

AGO 801515

information requested by the Alaska Public Utilities Commission Staff and the information provided on pages 9 and 10 of this order.

4. The Reserve Tax flow through provision is subject to the conditions that a report be filed with the Commission on January 15, April 15, July 15, and October 15 of 1976 and 1977 and a final report on January 15, 1978, setting forth the information requested by the Alaska Public Utilities Commission Staff and the information required on Page 11 of this order.

5. In addition to conditions specified elsewhere in this order the Purchased Gas Cost Adjustment clause and Severance Tax clause shall be subject to the following conditions and any increases in rates to the customers of Alaska Gas and Service Company pursuant to these clauses may not become effective until: (a) the information required by 3 AAC 48.275(a) is filed at least 45 days before the proposed effective date of the flow through of the increase in the cost of purchased gas or severance taxes; (b) at the time of filing the requirements in paragraph (5)(a) of this order Alaska Gas and Service Company shall file with the Commission a statement of the exact amount of the purchased gas cost adjustment increase and severance tax increase and the effective date that it wishes to increase rates to its customers based on these increases; (c) revised tariff sheets showing the rate increase to its customers shall be filed at least 15 days prior to the effective date of the rate increase; (d) Alaska Gas and Service Company, if ordered to do so by the Commission prior to the end of the 45-day period mentioned in Paragraph (5)(a) of this order,

AGO 801516

shall bear the burden of proof to justify its rates charged to its customers in accordance with generally accepted rate-making procedures and to prove that it is not receiving an unreasonable rate of return.

6. Regardless of whether the Commission orders a rate investigation pursuant to Paragraph 5 of this order and that Alaska Gas and Service Company bears the burden of proof as set forth in Paragraph 5, the increased rates proposed to offset the increased cost of purchased gas or increased severance taxes shall go into effect in accordance with these clauses.

7. If the Commission orders a rate investigation and orders that Alaska Gas and Service Company meet its burden of proof required in Paragraph 5 of this order, Alaska Gas and Service Company shall maintain accurate records of each customers' payments under the increased rates and shall refund to each customer any portion of the payments above the amount determined by the Commission in the rate investigation to be reasonable.

DATED AND EFFECTIVE at Anchorage, Alaska, this 17th day of December, 1975.

BY DIRECTION OF THE COMMISSION

(S E A L)



AGO 801517

SCR 106

CS HCR 142

Introduced: 5/5/76
Referred: Resources

IN THE SENATE

BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

SENATE CONCURRENT RESOLUTION NO. 106

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINTH LEGISLATURE - SECOND SESSION

Relating to the taking of state-owned royalty oil or gas in-kind and its disposal by sale.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the legislature by enactment of the Alaska Royalty Oil and Gas Development Board statute, AS 38.06. et seq., has established a clear policy of favoring the taking of state-owned royalty oil or gas in-kind and making that royalty available for in-state uses; and

WHEREAS the State of Alaska presently receives a one-eighth royalty on gas produced from the North Cook Inlet Gas Field in value, but has the right to receive this royalty in-kind; and

WHEREAS the commissioner of natural resources has entered into a contract for the sale and purchase of state-owned royalty gas from the North Cook Inlet Gas Field with Alaska Pipeline Company, an Alaskan corporation which sells natural gas in the Anchorage and North Kenai Road areas; and

WHEREAS the contract between the State of Alaska and Alaska Pipeline Company requires as a condition precedent to its becoming effective approval by a majority of each house of the Legislature;

BE IT RESOLVED by the Alaska State Legislature that approval of Alaska Royalty Gas Sale No. 76-1, the contract for the sale of state royalty gas from the North Cook Inlet Gas Field to Alaska Pipeline Company, is hereby approved.

AGO 801519

SCR104 REQUESTING THAT BIKE TRAILS AND PATHS BE OPENED FOR USE BY SNOWMOBILES WHEN SNOW CONDITIONS PERMIT

PRIME SPONSORS: COMMERCE BY REQUEST

	DATE	SEQ. NO.	JOURNAL PAGE	SENATE ACTION	DATE	SEQ. NO.	JOURNAL PAGE	HOUSE ACTION
**	05/03/76	01	1012	FIRST READING -- COMMITTEE REPORTS RESOURCES RULES				

SCR105 RELATING TO COMPETITIVE BIDDING FOR STATE CONTRACTS

PRIME SPONSORS: COMMERCE

	DATE	SEQ. NO.	JOURNAL PAGE	SENATE ACTION	DATE	SEQ. NO.	JOURNAL PAGE	HOUSE ACTION
**	05/04/76	01	1028	FIRST READING -- COMMITTEE REPORTS COMMERCE RULES				

SCR106 RELATING TO THE TAKING OF STATE-OWNED ROYALTY OIL OR GAS IN-KIND AND ITS DISPOSAL BY SALE

PRIME SPONSORS: RULES BY REQUEST OF: GOVERNOR

	DATE	SEQ. NO.	JOURNAL PAGE	SENATE ACTION	DATE	SEQ. NO.	JOURNAL PAGE	HOUSE ACTION
	05/05/76	01	1047	FIRST READING -- COMMITTEE REPORTS	05/16/76	05	1408	FIRST READING -- COMMITTEE REPORTS
	05/13/76	02	1156	RES -- DP04, NR03	05/17/76	06	1429	FIN -- DP05
	05/15/76	03	1209	SECOND READING	05/20/76	07	1486	SECOND READING
	05/15/76	04	1209	PASSED BY DIV 17-02-01	05/20/76	08	1486	PASSED BY VOICE VOTE
	05/24/76	09	1346	TRANSMITTED TO GOVERNOR				
**	05/28/76	10	1450	READ BY GOVERNOR -- SENT TO LT GOVERNOR				

SCR107 PAYING TRIBUTE TO JIM MCKEOWN

PRIME SPONSORS: RULES

	DATE	SEQ. NO.	JOURNAL PAGE	SENATE ACTION	DATE	SEQ. NO.	JOURNAL PAGE	HOUSE ACTION
	05/05/76	01	1047	FIRST READING -- COMMITTEE REPORTS	05/06/76	04	1244	FIRST READING -- COMMITTEE REPORTS
	05/05/76	02	1047	SECOND READING	05/07/76	05	1271	SECOND READING
	05/05/76	03	1047	PASSED BY VOICE VOTE	05/07/76	06	1271	PASSED BY VOICE VOTE
	05/12/76	07	1151	TRANSMITTED TO GOVERNOR				
**	05/15/76	08	1199	READ BY GOVERNOR -- SENT TO LT GOVERNOR				

AGO 801520

MESSAGES FROM THE GOVERNOR

Message of May 28 was read, stating the Governor has read the following resolutions and transmitted the enrolled and engrossed copies to the Lieutenant Governor's Office for permanent filing:

HOUSE RESOLUTION NO. 7

HOUSE CONCURRENT RESOLUTION NO. 86

SENATE COMMITTEE SUBSTITUTE FOR COMMITTEE SUBSTITUTE FOR HOUSE CONCURRENT RESOLUTION NO. 123

SENATE RESOLUTION NO. 7

HOUSE COMMITTEE SUBSTITUTE FOR COMMITTEE SUBSTITUTE FOR SENATE CONCURRENT RESOLUTION NO. 62

SENATE CONCURRENT RESOLUTION NO. 91

SENATE CONCURRENT RESOLUTION NO. 106

Message of May 28 was read, stating the Governor has signed the following resolutions and transmitted the enrolled and engrossed copies to the Lieutenant Governor's Office for permanent filing:

SENATE JOINT RESOLUTION NO. 54

HOUSE JOINT RESOLUTION NO. 67

HOUSE JOINT RESOLUTION NO. 77

Messages of May 26, 27 and 28 were read, stating the Governor has signed the following bills and transmitted the enrolled and engrossed copies to the Lieutenant Governor's Office for permanent filing:

HOUSE COMMITTEE SUBSTITUTE FOR SENATE BILL NO. 285 amended by the Free Conference Committee (Chapter 98, SLA 1976)

SENATE COMMITTEE SUBSTITUTE FOR COMMITTEE SUBSTITUTE FOR HOUSE BILL NO. 795 (Chapter 99, SLA 1976)

AGO 801521

HCS SSSB 647 The question being: "Shall the effective date clause on the above bill be adopted?" The roll was taken with the following result:

Yeas: 37 Anderson, H. Beirne, Bradley, Bradner, Brown, Buchholdt, Cotten, Cowper, Davis, Duncan, Eliason, Freeman, Gardiner, Gruening, Guy, Hackney, Haugen, Hershberger, Huntington, Itta, McKinnon, Malone, Miller, Naughton, Ose, Osterback, Ostrosky, Parker, Parr, Rhode, Rudd, Smith, Specking, Sullivan, Swanson, Urion, Wallis.

Nays: 2 M. Beirne, Fischer.

Excused: 1 Kelley.

And so, the effective date clause was adopted.

Mr. Specking gave notice of reconsideration of his vote on HOUSE COMMITTEE SUBSTITUTE FOR SPONSOR SUBSTITUTE FOR SENATE BILL NO. 647 on the next legislative day.

SECOND READING OF SENATE RESOLUTIONS

SCR 106 SENATE CONCURRENT RESOLUTION NO. 106 (taking of state-owned royalty oil or gas in-kind and its disposal by sale) was read the second time with the Finance Committee report (page 1429 of the journal).

The question being: "Shall SENATE CONCURRENT RESOLUTION NO. 106 pass the House?" On voice vote, it passed the House, was signed by the Speaker and the Chief Clerk and returned to the Senate.

CSHB 665 am Mr. Parr asked that the reconsideration of the vote on COMMITTEE SUBSTITUTE FOR HOUSE BILL NO. 665 amended (relating to statewide coordination of health planning) be taken up at this time.

THIRD READING OF HOUSE BILLS

COMMITTEE SUBSTITUTE FOR HOUSE BILL NO. 665 amended was automatically before the House in third reading at this time and was read the third time.

Mr. M. Beirne moved and asked unanimous consent that the above bill be returned to second reading for the purpose of rescinding action in failing to adopt amendment No. 2.

AGO 801522

and transmitting same for consideration. CSHB 661 am

The above message will be considered at a later time.

A message dated May 16, 1976 was read, stating the Senate has passed HOUSE BILL NO. 730 (providing for a tourism economic impact study and authorizing a data collection system) with the following amendment: HB 730

SENATE COMMITTEE SUBSTITUTE FOR HOUSE BILL NO. 730

and transmitting same for consideration.

The above message will be considered at a later time.

A message dated May 16, 1976 was read, stating the Senate has passed HOUSE BILL NO. 917 (relating to disaster relief for Western Alaska; effective date) with the following amendment: HB 917

Page 1, line 14: Delete "natural" insert "major"

Page 1, line 18: Delete "natural" insert "major"

and so, HOUSE BILL NO. 917 amended Senate is transmitted herewith for consideration.

The above message will be considered at a later time.

A message dated May 16, 1976 was read, stating the Senate has passed the following bill and it is transmitted herewith for consideration:

FIRST REFERENCE AND READING OF SENATE BILLS

SENATE BILL NO. 437 amended, by Croft, entitled: SB 437 am

"An Act making a special appropriation to the Department of Commerce and Economic Development, division of tourism, for group travel matching grants; and providing for an effective date."

was read the first time and referred to the Finance Committee.

REPORTS OF STANDING COMMITTEES

The Finance Committee has had SENATE CONCURRENT RESOLUTION NO. 106 (relating to the taking of state-owned royalty oil or gas in-kind and its disposal by sale) under consideration and a majority of the members of the Committee recommends it do pass. The report was signed by Mr. Malone, Chairman, and concurred in by Buchholdt, Haugen, Gruening, Cowper and Malone. SCR 106

SENATE CONCURRENT RESOLUTION NO. 106 was referred to the Rules Committee for placement on the calendar.

// Duncan absent
guy
Itta
Naughton

AGO 801523

And so, COMMITTEE SUBSTITUTE FOR SPONSOR SUBSTITUTE FOR HOUSE BILL NO. 549 (Finance) passed the Senate. CS SSHB 549 (Fin)

Senator Kerttula moved and asked unanimous consent that the roll call on the passage of COMMITTEE SUBSTITUTE FOR SPONSOR SUBSTITUTE FOR HOUSE BILL NO. 549 (Finance) be considered the roll call on the effective date clause. Without objection, it was so ordered.

COMMITTEE SUBSTITUTE FOR SPONSOR SUBSTITUTE FOR HOUSE BILL NO. 549 (Finance) was signed by the President and Secretary and returned to the House.

SECOND READING OF SENATE RESOLUTIONS

SENATE CONCURRENT RESOLUTION NO. 106 (taking of state-owned royalty oil or gas in-kind and its disposal by sale) was read the second time. SCR 106

SENATE CONCURRENT RESOLUTION NO. 106 was considered on final passage. A roll call was requested and appears as follows:

Yeas:	17	Bradley, Butrovich, Chance, Colletta, Croft, Ferguson, Huber, Kerttula, Meland, Miller, Orsini, Poland, Rader, Sackett, Tillion, Willis, Ziegler
Nays:	2	Hohman, Ray
Absent:	1	Rodey (vote DP in Resources)

Senate

And so, SENATE CONCURRENT RESOLUTION NO. 106 passed the Senate.

SENATE CONCURRENT RESOLUTION NO. 106 was referred to the Secretary for engrossment.

SPECIAL ORDERS

Senator Rodey moved and asked unanimous consent that he be excused from a call of the Senate for May 16 and 17. Without objection, Senator Rodey was excused.

Senator Tillion moved and asked unanimous consent that he be excused from a call of the Senate for May 16, 17 and 18. Without objection, Senator Tillion was excused.

AGO 801524

CS HB 893 (Fin) COMMITTEE SUBSTITUTE FOR HOUSE BILL NO. 893 (Finance) by the Finance Committee, entitled:

"An Act relating to general obligation bonds, bills and capital improvements of the state; and providing for an effective date."

was read the first time and referred to the Finance Committee.

CS HB 909 COMMITTEE SUBSTITUTE FOR HOUSE BILL NO. 909 by the Finance Committee, entitled:

"An Act making a special appropriation to the Department of Public Works for construction of a school at Anderson; and providing for an effective date."

was read the first time and referred to the Health, Education and Social Services Committee and the Finance Committee.

STANDING COMMITTEE REPORTS

SCR 105 The Resources Committee has had SENATE CONCURRENT RESOLUTION NO. 106 (taking of state-owned royalty oil or gas in-kind and its disposal by sale) under consideration and a majority of the committee recommends it do pass. The report was signed by Senator Poland, Chairman, and concurred in by Senators Rader, Croft and Rodey. Senators Bubrovich, Orsini and Meland signed: "no recommendation."

SENATE CONCURRENT RESOLUTION NO. 106 was referred to the Rules Committee.

SB 14 The Commerce Committee has had SENATE BILL NO. 14 (land classification) under consideration and a majority of the committee recommends it be replaced with COMMITTEE SUBSTITUTE FOR SENATE BILL NO. 14 (Commerce), entitled:

"An Act relating to agricultural land."

and that the committee substitute do pass. The report was signed by Senator Kerttula, Chairman, and concurred in by Senators Colletta and Bradley. Senator Ziegler signed: "no recommendation."

SENATE BILL NO. 14 was referred to the Rules Committee.

AGO 801525

Died in Finance
See SCR 106

Original Sponsor: Rules Committee by request of the Governor

Offered: 5/10/76
Referred: Finance

IN THE HOUSE BY THE RESOURCES COMMITTEE

CS FOR HOUSE CONCURRENT RESOLUTION NO. 142

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINTH LEGISLATURE - SECOND SESSION

Relating to the taking of state-owned royalty oil or gas in-kind and its disposal by sale.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the legislature by enactment of the Alaska Royalty Oil and Gas Development Board statute, AS 38.06, et seq., has established a clear policy of favoring the taking of state-owned royalty oil or gas in-kind and making that royalty available for in-state uses; and

WHEREAS the State of Alaska presently receives a one-eighth royalty on gas produced from the North Cook Inlet Gas Field in value, but has the right to receive this royalty in-kind; and

WHEREAS the commissioner of natural resources has entered into a contract for the sale and purchase of state-owned royalty gas from the North Cook Inlet Gas Field with Alaska Pipeline Company, an Alaskan corporation which sells natural gas in the Anchorage and North Kenai Road areas; and

WHEREAS the contract between the State of Alaska and Alaska Pipeline Company requires as a condition precedent to its becoming effective approval by a majority of each house of the Legislature;

BE IT RESOLVED by the Alaska State Legislature that Alaska royalty gas sale No. 76-1 and the contract providing for the sale of royalty gas from the North Cook Inlet gas field pertaining to it, between the state and the Alaska Pipeline Company, is hereby approved.

AGO 801526

Introduced: 5/4/76
Referred: Resources and Finance

IN THE HOUSE

BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

HOUSE CONCURRENT RESOLUTION NO. 142

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINTH LEGISLATURE - SECOND SESSION

Relating to the taking of state-owned royalty oil or gas in-kind and its disposal by sale.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the legislature by enactment of the Alaska Royalty Oil and Gas Development Board statute, AS 38.06. et seq., has established a clear policy of favoring the taking of state-owned royalty oil or gas in-kind and making that royalty available for in-state uses; and

WHEREAS the State of Alaska presently receives a one-eighth royalty on gas produced from the North Cook Inlet Gas Field in value, but has the right to receive this royalty in-kind; and

WHEREAS the commissioner of natural resources has entered into a contract for the sale and purchase of state-owned royalty gas from the North Cook Inlet Gas Field with Alaska Pipeline Company, an Alaskan corporation which sells natural gas in the Anchorage and North Kenai Road areas; and

WHEREAS the contract between the State of Alaska and Alaska Pipeline Company requires as a condition precedent to its becoming effective approval by a majority of each house of the Legislature;

BE IT RESOLVED by the Alaska State Legislature that approval of Alaska Royalty Gas Sale No. 76-1, the contract for the sale of state royalty gas from the North Cook Inlet Gas Field to Alaska Pipeline Company, is hereby approved.

AGO 801527

MEMORANDUM

May 8, 1976

SUBJECT: Contract for Sale of State Royalty Gas from the North Cook Inlet Field to Alaska Pipeline Company

TO: The Honorable Fred Brown

FROM: Gregg Erickson
Director of Research Services

Summary

As you requested on Friday, May 7, we have reviewed the unexecuted gas purchase contract identified as #76-1, between the State of Alaska (seller) and Alaska Pipeline Company (buyer) with particular reference to several specific questions you raised. Our analysis raises questions concerning the contract's pricing provisions and suggests that more extensive review by the Department of Natural Resources of Cook Inlet gas prices is called for. We also suggest that a requirement for in-state use of this gas be considered or, alternatively, that the contract be made unilaterally terminable by the state. In general, however, we find no obvious conditions or terms in the contract that appear contrary to the state's interests. Finally, we suggest revised wording for the resolution approving the contract.

Analysis

In general, the contract calls for the state to deliver to the buyer--currently the sole supplier of natural gas to Anchorage--an unspecified quantity of royalty gas received from its lessee in the North Cook Inlet field. It provides that the state shall direct its lessee (which in this case is Phillips Petroleum Company) to make these deliveries directly to the buyer who will then be responsible for its transportation to wherever it is to be consumed. Overall, a review of this contract reveals no glaring inequities or conditions which are

obviously not in the state's best interest. We do note, however, a number of minor policy issues and technical considerations which the legislature may wish to call to the attention of Commissioner Martin and the Alaska Royalty Oil and Gas Development Advisory Board.

The first question you raised concerned the point at which the royalty gas will be delivered to the buyer. The gas purchase contract itself does not specify this point. Under the terms of the lease between the State of Alaska and Phillips, the state has the right to take its royalty gas in kind but must do so on or adjacent to the lease from which it is produced. In the case of an offshore platform such as that from which the North Cook Inlet field is produced, this means that, absent other mutually acceptable arrangements, the state must take delivery of its in-kind royalty gas at the platform and arrange for its own transportation ashore. Thus, unless the state wishes to assume this responsibility, the contract provision as currently framed regarding point of delivery would seem to be the only appropriate alternative, i.e., that the state make its delivery to the buyer at the point where it receives delivery from the lessee.

As a practical matter, pipeline capacity sufficient to transport both the royalty and producer's gas to shore already exists, and Alaska Pipeline Company should be willing to pay Phillips a reasonable fee for the use of that capacity. Normally, both Phillips and Alaska Pipeline would be expected to have plenty of incentive to reach an agreement on these transportation charges. They represent additional income to Phillips without any additional expense (since the pipeline capacity is already in being) and, in the case of the Alaska Pipeline Company,

should be substantially lower than the cost of building and operating its own platform-to-shore pipeline.

The only situation where we could envision difficulties arising would be in the case where the lessee was willing to make significant immediate financial sacrifices in order to sabotage the royalty gas sale and thus regain for itself control over the entire production stream. If the cost of constructing a separate pipeline for the royalty share were economically prohibitive, denial of access of the existing facility might be sufficient to torpedo the entire deal. We do not see this as a likely eventuality, and if it were it is probable that the state could bring countervailing pressure to bear on the lessee. In any event, the possibility of such a confrontation would not seem to require any change in the contract here presented to the legislature.

You also asked us to review the provisions concerning the pricing of royalty gas delivered to the buyer. In general, this provision calls for the buyer to pay the state the higher of either the price the state would have received from Phillips Petroleum Company had it not taken its gas in kind, the highest price paid for gas elsewhere within 100 kilometers (62 miles) of the North Cook Inlet field, or a minimum price (which is 60.36¢ per Mcf as of July, 1977, escalating thereafter at the rate of 2¢ per Mcf annually).

We find these provisions unexceptionable, but we would call your attention to what appears to be unnecessary vagueness with respect to the provisions (on page 4 and repeated on page 5 of the contract) concerning how prices received for gas elsewhere in the Upper Cook Inlet Basin are to be related to the price of gas sold under this contract. The problem

arises from the fact that natural gas may be sold elsewhere within the 100 kilometer radius at a price higher than that which would be due under either of the other two pricing provisions, but that the conditions of delivery of that higher priced gas or its quality may be different enough to raise the question of whether the price is properly comparable to that received for gas purchased by the buyer. The contract states that these comparisons shall be made "with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of contract and connection charges." We would suggest that the semicolons preceding this phrase on pages 4 and 5 be deleted so that it will be clear the phrase applies only to the part of the sentence following the "(iii)", applying only to the comparison of prices within the basin and not to the minimum price or the price that the state would have received from Phillips.

In addition, you might consider it appropriate to work with the commissioner to develop substitute wording defining exactly how the BTU content and delivery pressure differences will influence the comparison prices, eliminating the reference to contract term and connection charges, and adding words indicating how the quantity of gas delivered is to affect the comparison. As it stands now, almost any difference in terms of delivery or quality could be used to justify an effective exemption from the "highest price received elsewhere" requirement.

It should be noted that the price currently received by the state for royalty gas produced from the North Cook Inlet field is an "imputed price". This means that it is not determined on the basis of actual

sales but rather on the basis of a "netback calculation" whereby one takes the price received for this gas in Japan and subtracts therefrom the costs of transportation and liquefaction incurred between the production platform and the delivery point in Tokyo. In the past the state has devoted little or no attention to actual verification of the validity of this imputed price, since it happens to be the highest price received for any gas in the basin. We have no reason to believe there is anything phony about the current price but would suggest that it would be appropriate in the future for the department to pay closer attention to this and other similarly determined prices in the basin since changes in one may influence others as well.

We would also call your attention to the fact that as the contract is currently written the state has no right of termination other than by mutual agreement. The buyer, on the other hand, may unilaterally terminate the contract prior to January 31, 1978. We would also point out in this context that although the "Whereas" paragraphs prior to the body of the contract indicate that the "buyer ...[delivers] natural gas for ultimate consumption within the State of Alaska", nowhere in the contract does the buyer agree to use or sell the gas purchased here only for consumption within the state. Conceivably the buyer could either export the gas from the state himself or sell it to some other party who would do the same thing. If the point of sale is greater than 100 kilometers from the North Cook Inlet field, the price of the sale would not result in any readjustment of the price paid by the buyer to the state. Since the purpose of this contract is to insure adequate supplies of natural gas for domestic consumption within the state, it would seem

logical that the contract include guarantees with respect to this matter or, alternatively, provisions allowing the state to unilaterally terminate the arrangement.

Finally, we would note that the "Resolved" clause of the resolution offered by the governor when he requested approval of this contract (HCR 142) would appear to be incorrectly worded. We would suggest that the following language be substituted:

> "BE IT RESOLVED by the Alaska State Legislature that Alaska royalty gas sale No. 76-1 and the contract providing for the sale of royalty gas from the North Cook Inlet gas field pertaining to it, between the State and the Alaska Pipeline Company, is hereby approved."*

We would also suggest that the contract itself be made a part of the legislature's official record by its inclusion in the House Committee Report, and thus the Supplement.

---

* If the legislature or a committee thereof believes that the above comments or other considerations require some revision of the contract, the most expeditious way of bringing them about might be to instruct the Department of Natural Resources or Mr. Fackler (executive director of the Royalty Board) to work with the proposed buyer to develop the necessary language. The resolved clause could then read:

> "BE IT RESOLVED by the Alaska State Legislature that Alaska Royalty Gas Sale No. 76-1 and the amended contract (submitted to the legislature on ___ May 1976 and appearing in the House Journal Supplement for ___ May 1976) providing for ..."

LEASES AND PERMITS

March 4, 1968

Phillips Petroleum Company
P. O. Box 1967
Houston, Texas

Re: Right-of-Way Permit Application
ADL 37819

Gentlemen:

This letter is to advise you that the Division of Lands has no objection to the installation of your proposed pipeline facility located in the Cook Inlet area and running from Latitude 60° 56' 10", Longitude 150° 42' 55" to Latitude 61° 04' 36", Longitude 150° 56' 54" as shown on the sketch plat attached hereto and made a part hereof. Providing, however, that your company will:

1. Take such reasonable precautions as necessary to prevent pollution or wastage of oil or other materials into Cook Inlet during both construction and maintenance of the pipeline;

2. Assume full responsibility for any adverse claims, liabilities, etc. as a result of construction or maintenance of the pipeline facility;

3. Take such precautions as necessary to cause the least interference with any commercial fishing activities in the vicinity of the pipeline;

4. Assure that the existing beach regimen and stability is maintained for that portion of the pipeline situated on tidelands; and

5. Assure that that portion of the pipeline located on tidelands is buried to sufficient depth so as to prevent damage to the pipeline or obstruction to any other users of the tidelands.

When construction is completed, and as-built plan and profiles are available, three copies of these should be forwarded to the Division of Lands for review. Upon review and approval, the plan and profile will be used to prepare the final right-of-way permit covering the subject lands. In addition, we propose that the right-of-way width for these pipelines be 50 feet either side of an established center line or a total of 100 feet overall.

Thank you for your cooperation.

Sincerely,

F. J. KEENAN, Acting Director

By: Howard J. Grey
Acting Tidelands Supervisor

HJG:dlm

Enclosure

Form No. DL-75
October 1964

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF LANDS

ADL 37819

APPLICATION FOR RIGHT-OF-WAY PERMIT

Date: February 15, 1968

The undersigned Phillips Petroleum Company residing at a Delaware Corporation with offices in Bartlesville, Oklahoma hereby applies to the Director of the Division of Lands, Department of Natural Resources, for Right-of-Way 100 feet in width and as shown on plat feet in length located in Section Various, Township 11N 10N 10N, Range 9W 8W, Seward Meridian, containing an area of _____ acres as shown on the plat attached hereto in triplicate copies, for the purpose of constructing and maintaining thereon a Two 10" gas pipelines and appurtenances for private, public, intermittent, yearlong use (strike inapplicable words).

State briefly the standards of construction of proposed improvements:

4 steel well pipe to be laid on the bottom of Cook Inlet

Constructed _____ Construction to begin approximately June, 1968

To be completed approximately 1 year later

If this application is approved, I agree to construct and maintain the improvements authorized in a workmanlike manner, to keep the area in a neat and sanitary condition; if said right-of-way is to be constructed across leased lands, I agree to reimburse the lessee for all damages to crops and improvements, to the extent of the fair market value thereof, which may be damaged or destroyed as the result of the construction of said right-of-way, and to comply with all the laws, rules and regulations pertaining thereto; and provided further that upon termination or relocation of the Right-of-Way for which application is herein made, I agree to remove or relocate the improvements and restore the area without cost to the State and to the satisfaction of the Director.

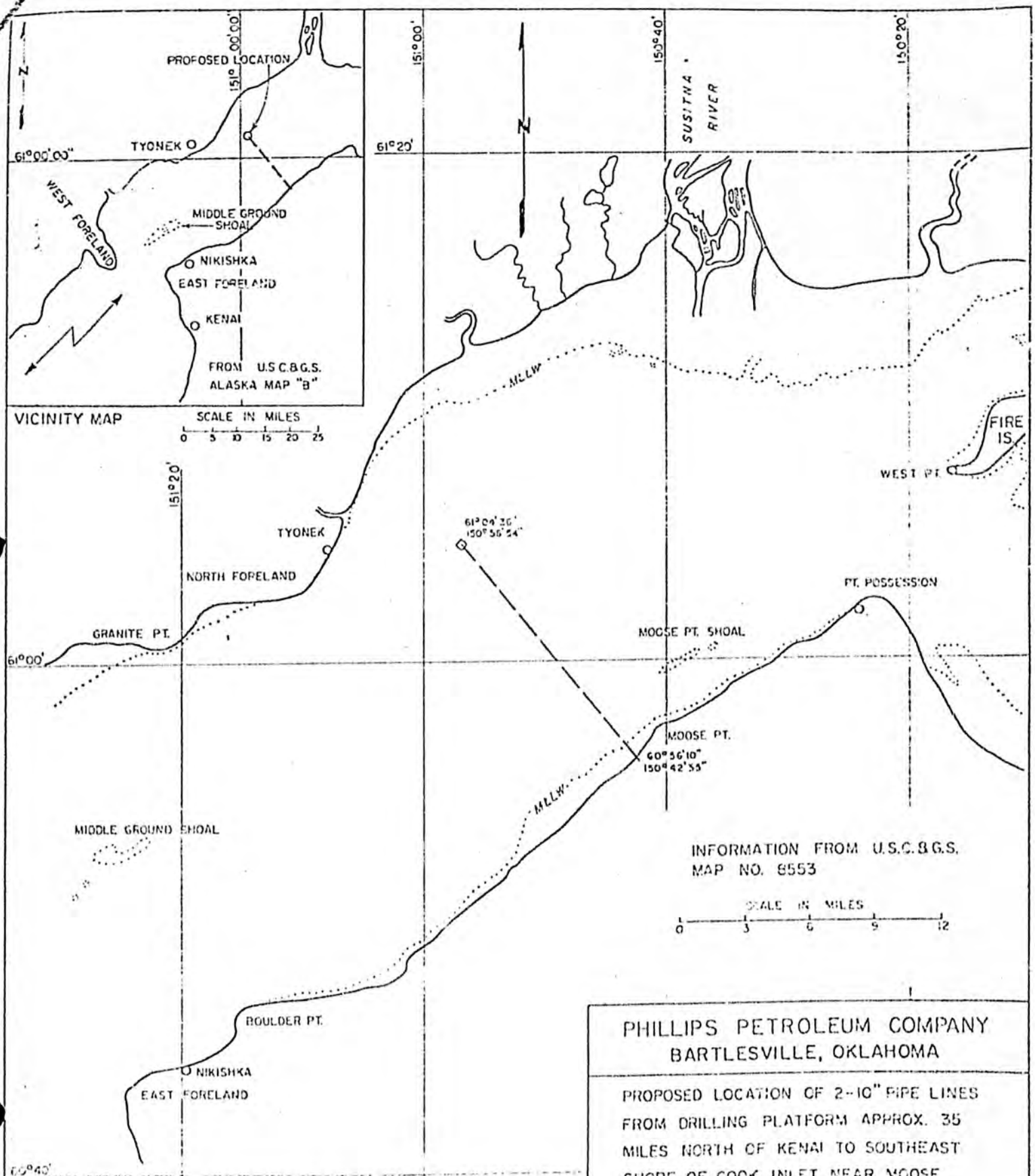
James H. Welch

James H. Welch, Right of Way Representative

(Instructions for preparation of plat: Attach triplicate copies of letter-size plat, show centerline and boundaries of right-of-way, show ties from centerline to establish monuments and section corners, show conflicts with other rights-of-way, if any, scale to 8" per mile, type of survey.)

AGO 801537

37810



PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA

PROPOSED LOCATION OF 2-10" PIPE LINES FROM DRILLING PLATFORM APPROX. 35 MILES NORTH OF KENAI TO SOUTHEAST SHORE OF COOK INLET NEAR MOOSE POINT, ALASKA.

AGO 801538

DATE JANUARY 22, 1968

From The Desk Of:

Pedro Denton

To: GREG Erickson

Attached is 2 copy of the right of way permit you requested. There was no significant correspondence in the file since the permit was issued.

3/22/77 PD

Chief, Minerals Section, Alaska Division Of Lands AGO 801539

Form No. DL 72
(Rev. June 1969)

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF LANDS

ADL No. 37017

RIGHT-OF-WAY PERMIT

THIS AGREEMENT made and entered into this 14th day of March, 1973, by and between the STATE OF ALASKA, acting by and through the Department of Natural Resources, Division of Lands, hereinafter referred to as the grantor and Phillips Gas Supply Corporation hereinafter referred to as the permittee.

WITNESSETH, that in accordance with the provisions of Sec. 38.05.330, A.S. and the rules and regulations promulgated thereunder, the permittee having filed an application for a right-of-way for: Pipeline on portion of Cook Inlet

with the Division of Lands together with a map showing the definite location thereon of the line of right-of-way which the permittee has adopted and agrees to be the specific and definite location of the aforesaid right-of-way, and

WHEREAS, it is understood and agreed by the permittee herein that, as a condition to the granting of the right-of-way applied for, the land covered by said right-of-way shall be used for no purpose other than the location, construction, operation and maintenance of the said right-of-way over and across the following described State lands, to wit:

As shown and described on Alaska Tidelands Survey No. 335, T.R.W.P. #14

running as above feet in length and/or containing as above acres, more or less and shall extend a width of _____ feet.

TO HAVE AND TO HOLD the same until the above described land shall no longer be used for the above-mentioned purpose and subject to conditions and reservations elsewhere set forth herein.

The sketch map revealing the right-of-way granted herein shall be attached hereto and made a part hereof.

In the event that the right-of-way herein granted shall in any manner conflict with or overlap a previously granted right-of-way the permittee herein shall use this right-of-way in such a manner as not to interfere with the peaceful use and enjoyment of the previously issued right-of-way and no improvements shall be constructed by the permittee herein upon the overlapping area unless the consent therefor has first been obtained from the permittee under the pre-existing right-of-way.

The permittee in the exercise of the rights and privileges granted by this

FILED
Division of Lands
Dept. of Natural Resources

indenture shall comply with all regulations now in effect or as hereafter established by the Division of Lands and all other Federal, State or municipal laws, regulations or ordinances applicable to the area herein granted.

Upon abandonment, termination, revocation or cancellation of this indenture, the permittee shall within 90 days remove all structures and improvements from the area herein granted, except those owned by the grantor, and shall restore the area to the same or similar condition as the same was upon the issuance of this permit. Should the permittee fail or refuse to remove said structures or improvements, within the time allotted, they shall revert to and become the property of the grantor. However, the permittee shall not be relieved of the cost of the removal of the structures, improvements and/or the cost of restoring the area. Provided further, however, that the grantor, in his discretion, may alter or modify the requirements contained in this provision if it is to the best interest of Alaska to do so.

The permittee shall utilize the lands herein granted consistent with the purposes of the proposed use, as revealed by the application therefor, and shall maintain the premises in a neat and orderly manner and shall adopt and apply such safety measures as shall be necessary, proper and prudent with respect to the use to which the land is subjected.

The permittee shall take all reasonable precaution to prevent and suppress brush and forest fires. No material shall be disposed of by burning in open fire during the closed season unless a permit therefor has first been obtained from the agency empowered by law to issue such permits.

Prior to any construction or development that will use, divert, obstruct, pollute or utilize any of the waters of the State, the permittee shall first obtain approval therefor from the Commissioner of the Department of Fish and Game and file an image copy thereof with the grantor.

Any lands included in this permit which are sold under a contract to purchase shall be subject to this permit. Upon issuance of title to the purchaser, this permit shall remain in effect until its date of expiration.

In case the necessity for the right-of-way shall no longer exist, or the permittee should abandon or fail to use the same, then this permit shall terminate.

The State of Alaska shall be forever wholly absolved from any liability for damages which might result to the permittee herein on account of this permit having been cancelled, forfeited, or terminated prior to the expiration of the full time for which it was issued.

NOW THEREFOR, in accordance with the provisions of Sec. 38.05.330, A.S. and the rules and regulations promulgated thereunder and in accordance with the conditions heretofore set forth or attached hereto and made a part hereof, the permittee herein is hereby authorized to locate, construct, operate and maintain said right-of-way over and across the lands herein described.

IN WITNESS WHEREOF, the said grantor has caused these presents to be signed in duplicate and the permittee herein has hereunto affixed his signature on the

day and year first above written.

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

By: _____
Chief, Lands Section
Division of Lands

PHILLIPS GAS SUPPLY CORPORATION

X _____
Attorney-in-fact Vice President

UNITED STATES OF AMERICA)
State of Alaska) ss.

This is to certify that on the 12 day of May 19 70, before me, the undersigned Notary Public, personally appeared Howard A. Lenz known to me and known by me to be the Chief Water Resources of the Division of Lands of the Department of Natural Resources, and acknowledged to me that he executed the foregoing instrument for and on behalf of said State, freely and voluntarily for the use and purposes therein set forth.

IN TESTIMONY WHEREOF, I have hereunto set my hand and affixed my official seal, the day and year in this certificate first above written.

_____
Notary Public in and for the State of Alaska
My commission expires 2-19-71

UNITED STATES OF AMERICA)
State of ~~Alaska~~ Oklahoma) ss.
County of Washington

This is to certify that on this X 3 day of April 19 70, before me, the undersigned Notary Public, personally appeared Jack Tarner to me personally known to be one of the persons described in and who executed the within instrument and the said Jack Tarner acknowledged to me that he signed and executed the same freely and voluntarily for the uses and purposes therein mentioned. X

IN TESTIMONY WHEREOF, I have hereunto set my hand and affixed my official seal, the day and year in this certificate first above written.

_____
Notary Public in and for the State of ~~Alaska~~ Oklahoma
My commission expires 12-7-71

AGO 801542

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

M E M O R A N D U M March 31, 1977

SUBJECT: Phillips Gas Supply Corporation pipeline right-of-way permit.

TO: Gregg K. Erickson
Director, Division of Research Services

FROM: Randolph Berry RSB
Legislative Counsel

This is in response to your request for an opinion whether the right-of-way permit issued to the Phillips Gas Supply Corp. for its pipeline in Cook Inlet may be cancelled and a lease under the Right-of-Way Leasing Act (AS 38.35) may substituted.

Unfortunately, due to ambiguities in the language of the right-of-way permit as well as in the regulations under which it was issued, it is not possible to give a straight-forward and definite answer to the question.

The form used by the Division of Lands in issuing this right-of-way permit contains conflicting language supporting both the view that the permit constituted a grant of an easement in perpetuity so long as the permittee used it for pipeline purposes and the contrasting view that the permit may be cancelled by the state. The language of the grant of the permit reads:

> "To have and to hold the same until the above described land shall no longer be used for the above-mentioned purpose and subject to conditions and reservations elsewhere set forth herein."

Standing alone, this would seem to clearly indicate that the right-of-way was perpetual and not cancellable so long as the permittee continued to operate its pipeline.

However, two other provisions of the document appear to be in irreconcilable conflict with the above language. The first of these, dealing with removal of structures and improvements, states:

> "Upon abandonment, termination, revocation or cancellation of this indenture, the permittee shall within 90 days remove all structures and improvements from the area herein granted..."

Since failure to continue to use the right-of-way by the permittee is spoken of elsewhere in the document as leading to termination of the permit, the references here to "revocation" and "cancellation" imply that the state has retained the power to end the permit for other reasons as well (but not specified in the agreement).

The other clause of the agreement supporting the view that the grant was not intended to be irrevocable reads as follows:

> The State of Alaska shall be forever wholly absolved from any liability for damages which might result to the permittee herein on account of this permit having been cancelled, forfeited, or terminated prior to the expiration of the full time for which it was issued."

This language, taken literally, would appear to allow the State to cancel the permit at will without liability.

There are two separate sections in the regulations issued by the Department of Natural Resources which provide for the issuance of right-of-way permits. 11 AAC 58.200 (Right of Way or Easement Permit) is located in Chapter 58 (Leasing of Lands). 11 AAC 62.810 (Tideland Right-of-Way and/or Easement Permits) is located in Chapter 62 (Tide and Submerged Lands). Both sections specify application on Form DL-75, which the applicant in this case used. No distinction is made either on the application form or the permit document indicating under which section the permit was issued, and consequently, which chapter of the regulations governs. Chapter 58 does not contain any reference to the duration of permits. In Chapter 62 various types of tideland permits are provided for and there is an ambiguous section on duration of permits (11 AAC 62.720) which states that "the permits shall not exceed five years in duration, but are renewable pursuant to sec. 790 of this chapter..." This section unfortunately does not clearly specify which classes of permits to which it was intended to imply. It is apparently the view of the Division of Lands that it applies to "tideland permits" (11 AAC 62.720) but not to "tideland right-of-way permits." (11 AAC 62.810). Further, there was apparently no practice on the part of the Division of Lands to distinguish between right-of-way permits issued for tide and submerged lands and for uplands, in spite of the separate sections of the regulations providing for right-of-way permits.

In view of all of the above, it seems almost a certainty that any attempt by the state to cancel the permit would be litigated by the permittee. Due in considerable part to the past practice by the Division of Lands of considering and treating right-of-way permits to be of continuing validity so long as used for the purpose granted, I feel that the odds of prevailing weigh slightly in favor of the permittee. However, I feel that there is sufficient argument that the permit is revocable by the state so that an attempt to do so by the state could not be considered to be unsupportable.

RB:hjd

STATE
of ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Minerals And Energy Management

MEMORANDUM

TO: Elke Kallab
Research Analyst
Legislative Affairs Agency

DATE : April 13, 1977

FROM: Pete Nelson
Land Management Officer III

SUBJECT: North Cook Inlet Gas Field

Attached are copies of the five (5) competitive oil and gas leases within the subject field. Philips Petroleum Company just acquired interests in these lease as follows:

ADL 17589	1/31/62
ADL 17590	6/1/67
ADL 18740	10/11/68
ADL 18741	10/11/68
ADL 37831	6/16/67

AGO 801546

FORM NO. DL-1
(REVISED APRIL, 1961)

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

LEASE NO. ADL 18741

Competitive Oil and Gas Lease

THIS LEASE, dated the 1st day of September, 1962, is made by and between the State of Alaska, acting by and through the Director of the Division of Lands, Department of Natural Resources or his authorized agent, hereinafter called "lessor", and

Pan American Petroleum Corporation

hereinafter called "Lessee", whether one or more.

1. GRANT. For and in consideration of a cash bonus and the first year's rental, the receipt of which is hereby acknowledged, and of the rentals, royalties, covenants, and conditions herein contained on the part of the Lessee to be paid, kept and performed, and subject to the conditions and reservations herein contained, Lessor does hereby grant and lease unto Lessee, exclusively, without warranty, for the sole and only purposes of exploration, development, production, processing and marketing of oil, gas, and associated substances produced therewith, and of installing pipe lines and structures thereon to find, produce, save, store, treat, process, transport, take care of and market all such substances, and for drilling water wells and taking underground and surface water for use in its operations thereon, and for housing and boarding employees in its operation thereon, the following described tract of land in Alaska:

S-13-6-27

containing 5120 acres, more or less, hereinafter called "said land".

For the purposes of this lease, said land contains 8 legal subdivisions, as shown on the plat of said land attached hereto, marked Exhibit A and by this reference made a part of this lease.

If said land is described above by protracted legal sudivisions, or by officially designated tract numbers, and Lessor hereafter causes said land to be surveyed under the public land rectangular system, the boundaries of said land shall be those established by such survey, when approved, subject, however, to the provisions of the regulations relating to such surveys.

2. "OIL AND GAS". "Oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced and saved in liquid form at the well by ordinary production methods. "Gas" means all natural gas and all hydrocarbons produced at the well not defined herein as oil. "Associated substances" means all substances produced in association with oil or gas and not defined herein as oil or gas.

3. TERM. This lease is issued for an initial primary term of five years from the date hereof, subject to extension as provided in Paragraph 4 hereof, and shall continue so long thereafter as oil and gas or either or any of them are produced in paying quantities from said land; provided, that this lease may be extended beyond its primary term as provided in Paragraph 5 hereof and shall not expire under the conditions set forth in Paragraphs 6, 7, and 8 hereof.

4. EXTENSION BY SUSPENSION OF OPERATIONS. If, prior to the expiration of the primary term, Lessor, in the interest of conservation, directs or assents to the suspension of all operations and production, if any, hereunder, the primary term will be extended by adding the period of suspension thereto.

5. EXTENSION BY UNIT PRODUCTION (a) This lease shall without application be extended beyond its primary term if upon or prior to the expiration date of such term the lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, production of oil or gas is had in paying quantities under the agreement, and a portion of such production is allocated to said land under the agreement. In such event this lease shall continue in effect so long as it remains subject to such agreement and action production under said agreement is allocated to said land; (b) The Commissioner may, in his discretion provide for the extension of the term of this lease, if such lease is on the expiration date thereof included in an approved unit plan or if it is included in a program of secondary recovery operation designed to bring about or restore production, provided, however, that if any lease or portion thereof is eliminated from such unit plan or recovery program, or if such unit plan or recovery program is terminated, then no such lease or portion thereof shall continue in full force and effect for ninety (90) days from the date of such elimination or termination and so long thereafter as drilling or redrilling operations are being conducted thereon and so long thereafter as oil or gas is produced in paying quantities.

6. EXTENSION BY DRILLING. (a) If production shall have been obtained in paying quantities during the primary term, and if, at the end of the primary term, or at any time prior to the end of the primary term, such production shall have ceased from any cause, or in the event production shall at any time or times after the expiration of the primary term cease from any cause, then this lease shall not terminate if the Lessee commences drilling or reworking operations (either in a well from which such production has ceased or in a new well) within sixty days after the cessation of production, and the lease shall remain in full force and effect so long as such operations are prosecuted with reasonable diligence or are suspended under Paragraph 27 hereof; and, if such drilling or reworking operations result in the production of oil or gas, the lease shall remain in full force and effect so long as oil or gas is produced therefrom in paying quantities; (b) if actual drilling has commenced on the expiration date of the primary terms of the lease and is continued with reasonable diligence, such operations to include redrilling, sidetracking or other means necessary to reach the originally proposed bottom hole location, the lease shall continue in full force and effect until ninety (90) days after such drilling had ceased and for so long thereafter as oil or gas is produced in paying quantities; (c) if all or part of the lands covered by the lease are lands that have been selected by Alaska under laws of the United States granting lands to Alaska and the conditional lease was issued thereon, the term of the lease shall be extended for a period equal to the period during which the lease was conditional.

7. EXTENSION BY SHUT-IN PRODUCTION. If, upon the expiration of the primary term or at any time or times thereafter, there is on said land a well capable of producing oil or gas in paying quantities, this lease shall not expire because Lessee fails to produce the same unless Lessor gives notice to Lessee allowing a reasonable time, which shall not be less than sixty days, after such notice to place the well on a producing status, and Lessee fails to do so; provided, that after such status is established such production shall continue on the said land unless and until suspension of production is allowed by Lessor.

8. EXTENSION BY SUSPENSION OF PRODUCTION. This lease shall not expire because of any suspension of operations in or upon or production from said land if such suspension is made under any order or with the consent of Lessor.

AGO 801547

AO 4-2-63

is to include the next day on which said office is open for business. Any rental paid for any one lease year shall be credited on any royalty for that year.

10. MINIMUM ROYALTY. Commencing with the lease year beginning on or after completion on said land of a well capable of producing oil or gas in paying quantities, Lessee shall pay Lessor, at the expiration of each lease year, in lieu of rental a minimum royalty equal to $1.00 per acre, or fraction thereof, then included in this lease, or the difference between the actual royalty paid on production during the year if less than $1.00 per acre and the prescribed minimum royalty.

11. ROYALTY ON PRODUCTION. Except for oil and gas used on said land for development and production or unavoidably lost, Lessee shall pay Lessor as royalty the following:

(a) On oil 12½ per cent in amount or value of the oil produced and saved and removed or sold from said land.

(b) On gas 12½ per cent in amount or value of the gas produced and saved and sold or used off said land or used for the extraction of natural gasoline or other products therefrom.

(c) On associated substances 12½ per cent in amount or value of such substances produced and saved and removed or sold from said lands.

12. REDUCTION OF ROYALTY RATES FOR DISCOVERY. If Lessee shall drill on said land and make the first discovery of oil or gas in commercial quantities in any geological structure, the royalty rate under this lease shall, instead of the rates prescribed in Paragraph 11, be five per cent for a period of ten years following the date of such discovery, and thereafter the royalty rates shall be those prescribed in Paragraph 11. If this lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, the five per cent royalty rate shall apply to all, but only, the production allocated to this lease under such agreement.

13. REDUCTION OF RENTAL AND ROYALTY. Rental or minimum royalty may be waived, suspended, or reduced, or royalty may be reduced on all of said land or any tract or portion thereof segregated for royalty purposes if Lessor finds that such relief is necessary for the purpose of encouraging the greatest ultimate recovery of oil or gas and is in the interest of conservation of natural resources and either that such relief is necessary in order to promote development or that the lease cannot be successfully operated under the terms provided herein.

14. ROYALTY IN KIND. Whenever, at the option of Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, Lessor elects to take its royalty in kind, Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon) to Lessor or to such individual, firm, or corporation as Lessor may designate all royalty oil and/or gas produced and saved from said land. Such oil and/or gas shall be in good and merchantable condition. Lessee shall, if necessary, furnish storage for royalty oil free of charge for thirty days after the end of the calendar month in which the oil is produced from said land; provided, that Lessee shall not be held liable for loss or destruction of royalty oil and/or gas from causes beyond Lessee's reasonable control. Should Lessee dehydrate or clean the oil or gas produced from said land, Lessee shall be entitled to an allowance of the actual cost of dehydrating or cleaning said royalty oil or gas.

15. ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts or gross production.

16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or, (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

17. PAYMENTS. All payments to Lessor under this lease shall be made payable to the Department of Revenue of the State of Alaska and shall be tendered to Lessor at the place designated under Paragraph 43 for giving notices to Lessor.

18. OFFSET WELLS. Lessee shall drill such wells as a reasonably prudent operator would drill to protect Lessor adequately from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas should be produced in a well on other land not owned by Lessor or on which Lessor receives a lower rate of royalty than the royalty under this lease, which well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and such well shall produce oil or gas in paying quantities for a period of thirty consecutive days, and if, after notice to Lessee and an opportunity to be heard, Lessor finds that production from such well is draining lands then subject to this lease, Lessee shall within 120 days after written demand by Lessor begin in good faith and prosecute diligently drilling operations for an offset well on said land. In lieu of drilling any well required by this paragraph, Lessee may with Lessor's consent compensate Lessor in full each month for the estimated loss of royalty through drainage in the amount determined by lessor.

19. OTHER WELLS. This lease contemplates the reasonable development of said land for oil and gas as the facts may justify. Upon discovery of oil or gas in paying quantities on said land, Lessee shall drill such wells as a reasonably prudent operator would drill having due regard for the interests of Lessor as well as the interests of Lessee.

20. DILIGENCE; PREVENTION OF WASTE. Lessee shall exercise reasonable diligence in drilling, producing, and operating wells on said land unless consent to suspend operations temporarily is granted by Lessor; shall carry on all operations hereunder in a good and workmanlike manner in accordance with approved methods and practices, having due regard for the prevention of waste of oil and gas and the entrance of water to the oil and gas bearing sands or strata to the destruction or injury of such deposits and the preservation and conservation of the property for future productive operations; shall use reasonable care and all proper safeguards to prevent the pollution of water; shall plug securely in an approved manner any well before abandoningit; shall allow Lessor to inspect all operations at any time; shall carry out at Lessee's expense all reasonable orders and requirements of Lessor relative to the prevention of waste and the preservation of said land, and on failure of Lessee so to do, Lessor shall have the right together with any other recourse available to it to enter on said land to repair damage or prevent waste at Lessor's expense; and shall abide by and conform to valid applicable rules and regulations of the Alaska Oil and Gas Conservation Commission and the regulations of Lessor relating to the matters covered by this paragraph in effect on the effective date hereof or hereafter in effect if not inconsistent with any specific provisions of this lease.

21. WELL LOCATIONS. Lessee shall within five days after spudding in a well advise Lessor in writing of the location and date of spudding of said well.

22. APPROVAL OF PLANS. Lessee shall not place into actual operation any plan or method for the purpose of stimulating or increasing production on said land other than plans and methods in common use without first having obtained the written approval of Lessor.

23. LOGS AND RECORDS. An electric log or radioactive log, if taken, and a descriptive geologic sample log, if taken, and a record of all tests run for each well drilled on said land, together with a plat showing the exact location of each such well, shall be filed with Lessor within thirty (30) days after such well has been completed, suspended, or abandoned. Any and all information filed by Lessee with Lessor in connection with this lease shall be available at all times for the confidential use of Lessor for the purpose of enforcing compliance with the terms, covenants, and conditions of this lease and the regulations of the Lessor but shall not be open for inspection by any person other than officers, or employees of Lessor and persons performing any function or work assigned to them by Lessor for a period of twenty four (24) months after the thirty (30) day filing period, except upon written consent of Lessee. Notwithstanding any other provision hereof, said information may be disclosed to any person where such disclosure is reasonably necessary for the administration of the functions, responsibilities, and duties vested by law in the Commissioner of the Department of Natural Resources or in the Division of Lands or the Director thereof. Including but not limited to functions, responsibilities, and duties arising in connection with any litigation or administrative adjudication relating to this lease or to the rights, duties, and obligations arising hereunder.

24. RECORDS. Lessee shall keep and have in its possession books and records showing the production and disposition of all oil and gas produced from said land and shall permit Lessor or its agents at all reasonable hours to examine the same. Such records and reports of production shall be based upon such methods and techniques as shall insure the most accurate figures reasonably available without requiring the Lessee to provide separate tankage for each well.

25. DAMAGES. Sect. 2 of Article VII of the Alaska Land Act, Chapt. 169, S.L.A., 1959, as amended, provides in part that no rights under reservations contained in certain leases or grants of Alaska land shall be exercised by Lessor or its Lessee until provision has been made to pay to the owner of the land upon which the reserved rights are sought to be exercised full payment for all damages sustained by said owner by reason of entering upon said land; provided, that if said owner for any cause whatever refuses or neglects to settle said damages, Lessor or its Lessee shall have the right to institute such legal proceedings in a court of competent jurisdiction wherein the land is situated as may be necessary to determine the damage which the owner of such land may suffer. Lessee hereby agrees to pay any damage that may become payable under said statutory provisions and to indemnify Lessor and hold it harmless from and

against any claims, demands, liabilities, and expenses arising from or in connection with such damage. The furnishing of a bond in compliance with this Lease will be regarded by Lessor as a sufficient provision for the payment of all damage that may become payable under said statutory provisions.

26. BONDS.

(a) Lessee shall maintain the bond furnished prior to the issuance of this lease in an amount equal to at least $2.00 per acre or fraction thereof contained in said land but not less than $1,000.00.

(b) Before beginning drilling operations on said land Lessee must have furnished and shall maintain a bond in an amount of at least $5,000.00.

(c) Lessee may, in lieu of the foregoing, furnish and maintain a statewide bond in the amount of $100,000.00

(d) Lessor may, after notice to Lessee and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified above in this paragraph where such greater amount is justified by the nature of the surface and its uses and improvements in the vicinity of said land and the degree of the risks involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph but will be considered by Lessor in determining the need for and the amount of any additional bond under this subparagraph.

(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

27. ACTS OF GOD. Should Lessee be prevented from complying with any expressed or implied covenant of this lease, from conducting drilling operations thereon, or from producing or marketing oil or gas from said land after efforts made in good faith, by reason of war, riots, acts of God, severe weather in the area of said land, acts of governmental authorities, failure or lack of adequate transportation facilities, or any other cause beyond Lessee's reasonable control whether similar to those enumerated or not, then while so prevented and for a reasonable time thereafter within which to resume operations, Lessee's obligation to comply with such covenant shall be suspended and Lessee shall not be liable for damages for failure to comply therewith. If drilling or reworking operations are suspended by virtue of this paragraph and the prosecution of such operations would have had the effect of preventing the expiration or termination of this lease, then this lease shall not terminate during the period which the obligation to perform such operations is suspended under this paragraph; provided, however, that nothing in this paragraph shall be construed to suspend the payment of rentals or of minimum royalties.

28. SUSPENSION. Lessor may from time to time direct or assent to the suspension of production or other operations or both under this lease if such action is necessary or justified in the interest of conservation.

29. RESERVATIONS. Lessor reserves the right to dispose of the surface of said land to others subject to this lease, and the right to authorize others by grant, lease, or permit subject to this lease and under such conditions as will prevent unnecessary or unreasonable interference with the rights of Lessee and operations under this lease, to enter upon and use said land:

(a) To explore for oil or gas by geological or geophysical means including the drilling of shallow core holes or stratigraphic tests to a depth of not more than 1,000 feet.

(b) To explore for, develop and remove natural resources other than oil, gas, and associated substances on or from said land.

(c) For nonexclusive easements and rights of way for any lawful purpose including shafts and tunnels necessary or appropriate for the working of said land or other lands for natural resources other than oil, gas or associated substances.

(d) For well sites and well bores of wells drilled from or through said land to explore for or produce oil, gas, and associated substances in and from other lands.

(e) For any other purpose now or hereafter authorized by law and not inconsistent with the rights of Lessee under this lease.

30. UNDERGROUND STORAGE. This lease does not authorize the subsurface storage of oil or gas except as a necessary incident to recycling pressure maintenance, repressuring, or other similar operations designed to increase the ultimate recovery of oil or gas or prevent the waste of oil or gas produced from said land or from any unit area of which the said land is a part. Lessor reserves the right to authorize the subsurface storage of oil or gas in said land by Lessee or by others in order to avoid waste or to promote conservation of natural resources and upon such conditions as will prevent unnecessary or unreasonable interference with the rights and operations of Lessee under this lease, including conditions prohibiting the storage of oil or gas without the consent of Lessee in any reservoir covered by this lease capable of producing oil or gas in paying quantities.

31. ASSIGNMENTS. This lease or any undivided interest herein may with the approval of Lessor be assigned or subleased as to said land or any one or more legal subdivisions included therein, or any separate and distinct zone or geological horizon underlying said land or such one or more legal subdivisions, to any person or persons qualified to hold a lease. No transfer of any interest in this lease including assignments of working or royalty interests and operating agreements and subleases shall be binding upon Lessor unless approved by Lessor. Lessee shall remain liable for all obligations under this lease accruing prior to the approval of such transfer. Approval of transfer of this lease or an interest therein will not be denied except (1) for failure to comply with the regulations, (2) in the discretion of Lessor, where the transfer covers any distinct zone or geological horizon, or (3) where Lessor determines that the best interests of Lessor justify such action. Applications for approval of a transfer under this paragraph must comply with the regulations and must be filed within ninety days after the date of final execution of the instrument of transfer. Where a transfer is made of all or a part of Lessee's interest in and to a portion of the acreage in said land the assigned acreage shall, at the option of Lessor, or may upon request of the transferee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

32. UNITIZATION. Whenever determined and certified by Lessor to be necessary or advisable in the public interest for the purpose of properly conserving the natural resources of any oil or gas pool, field or like area or any part thereof, which includes or underlies said land or any part thereof, Lessee may unite with other Lessees of Lessor or with others owning or operating lands not belonging to Lessor including lands belonging to the United States and with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the development or operation of the pool or field or like area or part thereof. Lessee shall within thirty days after demand by Lessor subscribe to such a cooperative or unit agreement, which agreement shall be reasonable and shall adequately protect all parties in interest including Lessor. Lessor may with the consent of Lessee establish, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of this lease if committed to any such cooperative or unit agreement and may make such regulations with reference to this lease with the like consent of Lessee in connection with the institution and operation of any such cooperative or unit agreement as Lessor may determine to be necessary or proper to secure the proper protection of the public interest. If a portion of said land is committed to an approved or prescribed unit agreement, the committed acreage shall at the option of Lessor and may upon the request of Lessee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

33. SURRENDER. Lessee may at any time make and file with Lessor a written surrender of all rights under this lease or any portion thereof comprising one or more legal subdivisions or, with the consent of Lessor, of any separate and distinct Zone or geological horizon underlying said lands or such one or more legal subdivisions thereof. Such surrender shall be effective as of the date of filing subject to the continued obligations of Lessee and his surety to make payment of all royalties theretofore accrued and to place all wells on the surrendered land or in the surrendered zones or horizons in condition satisfactory to Lessor for suspension or abandonment; thereupon, Lessee shall be released from all other obligations accrued or to accrue under this lease with respect to the surrendered lands, zones, or horizons

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[illegible] payment of rental and Lessee fails within sixty days after written notice of such default to commence to remedy and thereafter prosecute diligently operations to remedy such default, Lessor may cancel this lease if at that time there is no well on said land capable of producing oil or gas in paying quantities. If at such time there is on said land a well capable of producing oil or gas in paying quantities, this lease may be cancelled only by judicial proceedings. In the event of any cancellation under this paragraph, Lessee shall have the right to retain under this lease any and all drilling or producing wells as to which no default exists together with a parcel of land surrounding each such well or wells and such rights of way through said land as may be reasonably necessary to enable Lessee to drill and operate such retained well or wells.

35. EXCESS AREA. If for any reason said land includes more acreage than the maximum permitted under aplicable laws and/or regulations, this lease shall not be void but the acreage included in said land shall be reduced to the permitted maximum. Whenever Lessor determines that this lease so exceeds the permitted acreage and notifies Lessee stating the amount of acreage that must be eliminated, Lessee may within sixty days after such notice surrender one or more legal subdivisions included in said lands comprising at least the amount of acreage that must be eliminated. If such a surrender is not filed within such sixty days Lessor may terminate this lease as to the acreage that must be eliminated by mailing notice of such termination to Lessee describing the parcel or parcels eliminated. Such a notice shall have the effect of terminating this lease as to the parcel or parcels described in such notice.

36. RIGHTS ON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion of said lands, Lessee shall have the privilege at any time within a period of six months thereafter, or such extension thereof as may be granted by Lessor, of removing from said land or portion thereof all machinery, equipment, tools, and materials other than improvements needed for producing wells. Any materials, tools, appliances, machinery, structures, and equipment subject to removal as above provided which are allowed to remain on said land or portion thereof shall become the property of Lessor upon expiration of such period; provided, that Lessee shall remove any and all of such properties when so directed by Lessor. Subject to the foregoing, Lessee shall deliver up said lands or such portion or portions thereof in good order and condition.

37. INTEREST IN LAND. It is the intention of the parties that the rights vested in Lessee by this lease shall constitute an interest in real property in said land.

38. LESSOR INTEREST. If Lessor owns a lesser interest in the oil and gas deposits in said land than the entire and undivided fee simple estate, then the royalties and rentals herein provided shall be paid Lessor only in the proportion which its interest bears to the whole and undivided fee.

39. CONDITIONAL LEASE. If all or a part of said land is land that has been selected by the Lessor under laws of the United States granting lands to Lessor, but such land has not been patented to Lessor by the United States, then this lease is a conditional lease as provided by law until such patent become effective. If for any reason such a selection is not finally approved or such a patent does not become effective, and rental, royalty or minimum royalty payments made to Lessor under this lease will not be refunded.

40. DRILLING OPERATIONS. As used in this lease "drilling operations" mean any work or actual operations undertaken or commenced in good faith for the purpose of carrying out any of the rights, privileges or duties of Lessee under this lease, followed diligently and in due course by the construction of a road or derrick and/or other necessary structures for the drilling of an oil or gas well, and by the actual operation of drilling in the ground. Any such work or operations preliminary to drilling in the ground may be undertaken either on said land or in the vicinity of said land in any order Lessee shall see fit.

40. (a) ACTUAL DRILLING. As used in this lease, "actual drilling" means any and all operations necessary or convenient to the drilling of a well in the ground after the first drilling or spudding with equipment of sufficient size and capacity to drill to the total depth proposed for the well.

41. RULES AND REGULATIONS. As used in this lease "regulations" mean the applicable and valid oil and gas leasing regulations of the Commissioner of the Department of Natural Resources in effect on the effective date of this lease unless otherwise specified.

42. INTERPRETATION. As used in this lease words which are defined in the regulations have the meaning assigned by such definition except where the context clearly requires a different meaning. The paragraph headings are not a part of this lease and are inserted only for convenience.

43. NOTICES. Any notice required or permitted under this lease shall be in writing and shall be given by registered or certified mail, return receipt requested, addressed as follows:

To Lessor:
Director, Division of Lands
State of Alaska
344 Sixth Avenue
Anchorage, Alaska

To Lessee:
Pan American Petroleum Corporation
P. O. Box 712
Anchorage, Alaska

Any such notice shall be deemed given when delivered to the foregoing address. Either party may change the address to which such notices are to be sent, by a notice given in accordance with this paragraph.

44. HEIRS AND ASSIGNS. Subject to the other provisions of this lease, the covenants, conditions, and agreements contained in this lease shall extend to and be binding upon the heirs, executors, administrators, successors, or assigns of Lessor and Lessee.

45. WILDLIFE STIPULATIONS. This lease is subject to such stipulations as are attached.

IN WITNESS WHEREOF the parties have executed this lease.

Pan American Petroleum Corporation

BY: Ross W. Craig
Its Attorney-in-Fact
LESSEE

STATE OF ALASKA

By Norris C. Bakke Jr.
Norris C. Bakke, Jr.
Title Minerals Officer LESSOR

THE UNITED STATES OF AMERICA }
STATE OF ALASKA } ss.

This certifies that on the 28th day of August, 1962 before me, a notary public in and for the State of Alaska, duly commissioned and sworn, personally appeared NORRIS C. BAKKE, JR., to me known and known to me to be the person described in and who executed the foregoing lease on behalf of the State of Alaska as Director of the Division of Lands, Department of Natural Resources, or his authorized agent. The said NORRIS C. BAKKE, JR. executed said lease in my presence and, after being duly sworn according to law, stated to me under oath that he is the Director of the Division of Lands, Department of Natural Resources, or his authorized agent, and has authority pursuant to law to execute the foregoing lease as such Director, or authorized agent, on behalf of the State of Alaska, acting through the Division of Lands, Department of Natural Resources and that he executed the same freely and voluntarily as the free and voluntary act and deed of the said State of Alaska and for the Division of Lands, Department of Natural Resources.

WITNESS my hand and official seal of the day and year in this certificate above written.

John Kalaro) Notary Public in and for Alaska. My Commission expires 9-27-65

FORM NO. DL-1
(REVISED APRIL, 1961)

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

ADL 3783
LEASE NO. ADL ~~ADL 18255~~

Competitive Oil and Gas Lease

THIS LEASE, dated the 1st day of September, 1962, is made by and between the State of Alaska, acting by and through the Director of the Division of Lands, Department of Natural Resources or his authorized agent, hereinafter called "lessor", and SHELL OIL COMPANY, a Delaware Corp., 1008 W. Sixth Street, Los Angeles 54, Calif., ADL-QF #3; STANDARD OIL COMPANY OF CALIFORNIA, a Delaware Corp., 225 Bush Street, San Francisco 20, Calif., ADL-QF #2, and RICHFIELD OIL CORPORATION, a Delaware Corp., hereinafter called "Lessee", whether one or more. 555 S. Flower Street, Los Angeles 17, Calif., ADL-QF #

1. GRANT. For and in consideration of a cash bonus and the first year's rental, the receipt of which is hereby acknowledged, and of the rentals, royalties, covenants, and conditions herein contained on the part of the Lessee to be paid, kept and performed, and subject to the conditions and reservations herein contained, Lessor does hereby grant and lease unto Lessee, exclusively, without warranty, for the sole and only purposes of exploration, development, production, processing and marketing of oil, gas, and associated substances produced therewith, and of installing pipe lines and structures thereon to find, produce, save, store, treat, process, transport, take care of and market all such substances, and for drilling water wells and taking underground and surface water for use in its operations thereon, and for housing and boarding employees in its operation thereon, the following described tract of land in Alaska:

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containing 5051.00 acres, more or less, hereinafter called "said land".

For the purposes of this lease, said land contains 8 legal subdivisions, as shown on the plat of said land attached hereto, marked Exhibit A and by this reference made a part of this lease.

If said land is described above by protracted legal sudivisions, or by officially designated tract numbers, and Lessor hereafter causes said land to be surveyed under the public land rectangular system, the boundaries of said land shall be those established by such survey, when approved, subject, however, to the provisions of the regulations relating to such surveys.

2. "OIL AND GAS". "Oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced and saved in liquid form at the well by ordinary production methods. "Gas" means all natural gas and all hydrocarbons produced at the well not defined herein as oil. "Associated substances" means all substances produced in association with oil or gas and not defined herein as oil or gas.

3. TERM. This lease is issued for an initial primary term of five years from the date hereof, subject to extension as provided in Paragraph 4 hereof, and shall continue so long thereafter as oil and gas or either or any of them are produced in paying quantities from said land; provided, that this lease may be extended beyond its primary term as provided in Paragraph 5 hereof and shall not expire under the conditions set forth in Paragraphs 6, 7, and 8 hereof.

4. EXTENSION BY SUSPENSION OF OPERATIONS. If, prior to the expiration of the primary term, Lessor, in the interest of conservation, directs or assents to the suspension of all operations and production, if any, hereunder, the primary term will be extended by adding the period of suspension thereto.

5. EXTENSION BY UNIT PRODUCTION (a) This lease shall without application be extended beyond its primary term if upon or prior to the expiration date of such term the lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, production of oil or gas is had in paying quantities under the agreement, and a portion of such production is allocated to said land under the agreement. In such event this lease shall continue in effect so long as it remains subject to such agreement and action production under said agreement is allocated to said land; (b) The Commissioner may, in his discretion provide for the extension of the term of this lease, if such lease is on the expiration date thereof included in an approved unit plan or if it is included in a program of secondary recovery operation designed to bring about or restore production, provided, however, that if any lease or portion thereof is eliminated from such unit plan or recovery program, or if such unit plan or recovery program is terminated, then no such lease or portion thereof shall continue in full force and effect for ninety (90) days from the date of such elimination or termination and so long thereafter as drilling or redrilling operations are being conducted thereon and so long thereafter as oil or gas is produced in paying quantities.

6. EXTENSION BY DRILLING. (a) If production shall have been obtained in paying quantities during the primary term, and if, at the end of the primary term, or at any time prior to the end of the primary term, such production shall have ceased from any cause, or in the event production shall at any time or times after the expiration of the primary term cease from any cause, then this lease shall not terminate if the Lessee commences drilling or reworking operations (either in a well from which such production has ceased or in a new well) within sixty days after the cessation of production, and the lease shall remain in full force and effect so long as such operations are prosecuted with reasonable diligence or are suspended under Paragraph 27 hereof; and, if such drilling or reworking operations result in the production of oil or gas, the lease shall remain in full force and effect so long as oil or gas is produced therefrom in paying quantities; (b) if actual drilling has commenced on the expiration date of the primary terms of the lease and is continued with reasonable diligence, such operations to include redrilling, sidetracking or other means necessary to reach the originally proposed bottom hole location, the lease shall continue in full force and effect until ninety (90) days after such drilling had ceased and for so long thereafter as oil or gas is produced in paying quantities; (c) if all or part of the lands covered by the lease are lands that have been selected by Alaska under laws of the United States granting lands to Alaska and the conditional lease was issued thereon, the term of the lease shall be extended for a period equal to the period during which the lease was conditional.

7. EXTENSION BY SHUT-IN PRODUCTION. If, upon the expiration of the primary term or at any time or times thereafter, there is on said land a well capable of producing oil or gas in paying quantities, this lease shall not expire because Lessee fails to produce the same unless Lessor gives notice to Lessee allowing a reasonable time, which shall not be less than sixty days, after such notice to place the well on a producing status, and Lessee fails to do so; provided, that after such status is established such production shall continue on the said land unless and until suspension of production is allowed by Lessor.

8. EXTENSION BY SUSPENSION OF PRODUCTION. This lease shall not expire because of any suspension of operations in or upon or production from said land if such suspension is made under any order or with the consent of Lessor.

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9. RENTAL. This lease shall terminate on any anniversary date hereof prior to the completion on said land of a well capable of producing oil or gas in paying quantities, unless on or before said anniversary date Lessee shall pay or tender to Lessor as annual rental a sum equal to $1.00 per acre, or fraction thereof, then included in this lease, or unless such annual rental has been waived or suspended as provided in Paragraph 13 of this lease. If Lessor's office is not open for business on the anniversary date, the time for payment is extended to include the next day on which said office is open for business. Any rental paid for any one lease year shall be credited on any royalty for that year.

10. MINIMUM ROYALTY. Commencing with the lease year beginning on or after completion on said land of a well capable of producing oil or gas in paying quantities, Lessee shall pay Lessor, at the expiration of each lease year, in lieu of rental a minimum royalty equal to $1.00 per acre, or fraction thereof, then included in this lease, or the difference between the actual royalty paid on production during the year if less than $1.00 per acre and the prescribed minimum royalty.

11. ROYALTY ON PRODUCTION. Except for oil and gas used on said land for development and production or unavoidably lost, Lessee shall pay Lessor as royalty the following:

(a) On oil 12½ per cent in amount or value of the oil produced and saved and removed or sold from said land.

(b) On gas 12½ per cent in amount or value of the gas produced and saved and sold or used off said land or used for the extraction of natural gasoline or other products therefrom.

(c) On associated substances 12½ per cent in amount or value of such substances produced and saved and removed or sold from said lands.

12. REDUCTION OF ROYALTY RATES FOR DISCOVERY. If Lessee shall drill on said land and make the first discovery of oil or gas in commercial quantities in any geological structure, the royalty rate under this lease shall, instead of the rates prescribed in Paragraph 11, be five per cent for a period of ten years following the date of such discovery, and thereafter the royalty rates shall be those prescribed in Paragraph 11. If this lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, the five per cent royalty rate shall apply to all, but only, the production allocated to this lease under such agreement.

13. REDUCTION OF RENTAL AND ROYALTY. Rental or minimum royalty may be waived, suspended, or reduced, or royalty may be reduced on all of said land or any tract or portion thereof segregated for royalty purposes if Lessor finds that such relief is necessary for the purpose of encouraging the greatest ultimate recovery of oil or gas and is in the interest of conservation of natural resources and either that such relief is necessary in order to promote development or that the lease cannot be successfully operated under the terms provided herein.

14. ROYALTY IN KIND. Whenever, at the option of Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, Lessor elects to take its royalty in kind, Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon) to Lessor or to such individual, firm, or corporation as Lessor may designate all royalty oil and/or gas produced and saved from said land. Such oil and/or gas shall be in good and merchantable condition. Lessee shall, if necessary, furnish storage for royalty oil free of charge for thirty days after the end of the calendar month in which the oil is produced from said land; provided, that Lessee shall not be held liable for loss or destruction of royalty oil and/or gas from causes beyond Lessee's reasonable control. Should Lessee dehydrate or clean the oil or gas produced from said land, Lessee shall be entitled to an allowance of the actual cost of dehydrating or cleaning said royalty oil or gas.

15. ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts or gross production.

16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or, (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

17. PAYMENTS. All payments to Lessor under this lease shall be made payable to the Department of Revenue of the State of Alaska and shall be tendered to Lessor at the place designated under Paragraph 43 for giving notices to Lessor.

18. OFFSET WELLS. Lessee shall drill such wells as a reasonably prudent operator would drill to protect Lessor adequately from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas should be produced in a well on other land not owned by Lessor or on which Lessor receives a lower rate of royalty than the royalty under this lease, which well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and such well shall produce oil or gas in paying quantities for a period of thirty consecutive days, and if, after notice to Lessee and an opportunity to be heard, Lessor finds that production from such well is draining lands then subject to this lease, Lessee shall within 120 days after written demand by Lessor begin in good faith and prosecute diligently drilling operations for an offset well on said land. In lieu of drilling any well required by this paragraph, Lessee may with Lessor's consent compensate Lessor in full each month for the estimated loss of royalty through drainage in the amount determined by lessor.

19. OTHER WELLS. This lease contemplates the reasonable development of said land for oil and gas as the facts may justify. Upon discovery of oil or gas in paying quantities on said land, Lessee shall drill such wells as a reasonably prudent operator would drill having due regard for the interests of Lessor as well as the interests of Lessee.

20. DILIGENCE; PREVENTION OF WASTE. Lessee shall exercise reasonable diligence in drilling, producing, and operating wells on said land unless consent to suspend operations temporarily is granted by Lessor; shall carry on all operations hereunder in a good and workmanlike manner in accordance with approved methods and practices, having due regard for the prevention of waste of oil and gas and the entrance of water to the oil and gas bearing sands or strata to the destruction or injury of such deposits and the preservation and conservation of the property for future productive operations; shall use reasonable care and all proper safeguards to prevent the pollution of water; shall plug securely in an approved manner any well before abandoningit; shall allow Lessor to inspect all operations at any time; shall carry out at Lessee's expense all reasonable orders and requirements of Lessor relative to the prevention of waste and the preservation of said land, and on failure of Lessee so to do, Lessor shall have the right together with any other recourse available to it to enter on said land to repair damage or prevent waste at Lessor's expense; and shall abide by and conform to valid applicable rules and regulations of the Alaska Oil and Gas Conservation Commission and the regulations of Lessor relating to the matters covered by this paragraph in effect on the effective date hereof or hereafter in effect if not inconsistent with any specific provisions of this lease.

21. WELL LOCATIONS. Lessee shall within five days after spudding in a well advise Lessor in writing of the location and date of spudding of said well.

22. APPROVAL OF PLANS. Lessee shall not place into actual operation any plan or method for the purpose of stimulating or increasing production on said land other than plans and methods in common use without first having obtained the written approval of Lessor.

23. LOGS AND RECORDS. An electric log or radioactive log, if taken, and a descriptive geologic sample log, if taken, and a record of all tests run for each well drilled on said land, together with a plat showing the exact location of each such well, shall be filed with Lessor within thirty (30) days after such well has been completed, suspended, or abandoned. Any and all information filed by Lessee with Lessor in connection with this lease shall be available at all times for the confidential use of Lessor for the purpose of enforcing compliance with the terms, covenants, and conditions of this lease and the regulations of the Lessor but shall not be open for inspection by any person other than officers, or employees of Lessor and persons performing any function or work assigned to them by Lessor for a period of twenty four (24) months after the thirty (30) day filing period, except upon written consent of Lessee. Notwithstanding any other provision hereof, said information may be disclosed to any person where such disclosure is reasonably necessary for the administration of the functions, responsibilities, and duties vested by law in the Commissioner of the Department of Natural Resources or in the Division of Lands or the Director thereof. Including but not limited to functions, responsibilities, and duties arising in connection with any litigation or administrative adjudication relating to this lease or to the rights, duties, and obligations arising hereunder.

24. RECORDS. Lessee shall keep and have in its possession books and records showing the production and disposition of all oil and gas produced from said land and shall permit Lessor or its agents at all reasonable hours to examine the same. Such records and reports of production shall be based upon such methods and techniques as shall insure the most accurate figures reasonably available without requiring the Lessee to provide separate tankage for each well.

25. DAMAGES. Sect. 2 of Article VII of the Alaska Land Act, Chapt. 169, S.L.A., 1959, as amended, provides in part that no rights under reservations contained in certain leases or grants of Alaska land shall be exercised by Lessor or its Lessee until provision has been made to pay to the owner of the land upon which the reserved rights are sought to be exercised full payment for all damages sustained by said owner by reason of entering upon said land; provided, that if said owner for any cause whatever refuses or neglects to settle said damages, Lessor or its Lessee shall have the right to institute such legal proceedings in a court of competent jurisdiction wherein the land is situated as may be necessary to determine the damage which the owner of such land may suffer. Lessee hereby agrees to pay any damage that may become payable under said statutory provisions and to indemnify Lessor and hold it harmless from and against any claims, demands, liabilities, and expenses arising from or in connection with such damage. The furnishing of a bond in compliance with this lease will be regarded by Lessor as a sufficient provision for the payment of all damage that may become payable under said statutory provisions.

26. BONDS.

(a) Lessee shall maintain the bond furnished prior to the issuance of this lease in an amount equal to at least $2.00 per acre or fraction thereof contained in said land but not less than $1,000.00.

(b) Before beginning drilling operations on said land Lessee must have furnished and shall maintain a bond in an amount of at least $5,000.00.

(c) Lessee may, in lieu of the foregoing, furnish and maintain a statewide bond in the amount of $100,000.00

(d) Lessor may, after notice to Lessee and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified above in this paragraph where such greater amount is justified by the nature of the surface and its uses and improvements in the vicinity of said land and the degree of the risks involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph but will be considered by Lessor in determining the need for and the amount of any additional bond under this subparagraph.

(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

27. ACTS OF GOD. Should Lessee be prevented from complying with any expressed or implied covenant of this

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each such well, shall be filed with Lessor within thirty (30) days after such well has been completed, suspended, or abandoned. Any and all information filed by Lessee with Lessor in connection with this lease shall be available at all times for the confidential use of Lessor for the purpose of enforcing compliance with the terms, covenants, and conditions of this lease and the regulations of the Lessor but shall not be open for inspection by any person other than officers, or employees of Lessor and persons performing any function or work assigned to them by Lessor for a period of twenty four (24) months after the thirty (30) day filing period, except upon written consent of Lessee. Notwithstanding any other provision hereof, said information may be disclosed to any person where such disclosure is reasonably necessary for the administration of the functions, responsibilities, and duties vested by law in the Commissioner of the Department of Natural Resources or in the Division of Lands or the Director thereof. Including but not limited to functions, responsibilities, and duties arising in connection with any litigation or administrative adjudication relating to this lease or to the rights, duties, and obligations arising hereunder.

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(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

27. ACTS OF GOD. Should Lessee be prevented from complying with any expressed or implied covenant of this lease, from conducting drilling operations thereon, or from producing or marketing oil or gas from said land after efforts made in good faith, by reason of war, riots, acts of God, severe weather in the area of said land, acts of governmental authorities, failure or lack of adequate transportation facilities, or any other cause beyond Lessee's reasonable control whether similar to those enumerated or not, then while so prevented and for a reasonable time thereafter within which to resume operations, Lessee's obligation to comply with such covenant shall be suspended and Lessee shall not be liable for damages for failure to comply therewith. If drilling or reworking operations are suspended by virtue of this paragraph and the prosecution of such operations would have had the effect of preventing the expiration or termination of this lease, then this lease shall not terminate during the period which the obligation to perform such operations is suspended under this paragraph; provided, however, that nothing in this paragraph shall be construed to suspend the payment of rentals or of minimum royalties.

28. SUSPENSION. Lessor may from time to time direct or assent to the suspension of production or other operations or both under this lease if such action is necessary or justified in the interest of conservation.

29. RESERVATIONS. Lessor reserves the right to dispose of the surface of said land to others subject to this lease, and the right to authorize others by grant, lease, or permit subject to this lease and under such conditions as will prevent unnecessary or unreasonable interference with the rights of Lessee and operations under this lease, to enter upon and use said land:

(a) To explore for oil or gas by geological or geophysical means including the drilling of shallow core holes or stratigraphic tests to a depth of not more than 1,000 feet.

(b) To explore for, develop and remove natural resources other than oil, gas, and associated substances on or from said land.

(c) For nonexclusive easements and rights of way for any lawful purpose including shafts and tunnels necessary or appropriate for the working of said land or other lands for natural resources other than oil, gas or associated substances.

(d) For well sites and well bores of wells drilled from or through said land to explore for or produce oil, gas, and associated substances in and from other lands.

(e) For any other purpose now or hereafter authorized by law and not inconsistent with the rights of Lessee under this lease.

30. UNDERGROUND STORAGE. This lease does not authorize the subsurface storage of oil or gas except as a necessary incident to recycling pressure maintenance, repressuring, or other similar operations designed to increase the ultimate recovery of oil or gas or prevent the waste of oil or gas produced from said land or from any unit area of which the said land is a part. Lessor reserves the right to authorize the subsurface storage of oil or gas in said land by Lessee or by others in order to avoid waste or to promote conservation of natural resources and upon such conditions as will prevent unnecessary or unreasonable interference with the rights and operations of Lessee under this lease, including conditions prohibiting the storage of oil or gas without the consent of Lessee in any reservoir covered by this lease capable of producing oil or gas in paying quantities.

31. ASSIGNMENTS. This lease or any undivided interest herein may with the approval of Lessor be assigned or subleased as to said land or any one or more legal subdivisions included therein, or any separate and distinct zone or geological horizon underlying said land or such one or more legal subdivisions, to any person or persons qualified to hold a lease. No transfer of any interest in this lease including assignments of working or royalty interests and operating agreements and subleases shall be binding upon Lessor unless approved by Lessor. Lessee shall remain liable for all obligations under this lease accruing prior to the approval of such transfer. Approval of transfer of this lease or an interest therein will not be denied except (1) for failure to comply with the regulations, (2) in the discretion of Lessor, where the transfer covers any distinct zone or geological horizon, or (3) where Lessor determines that the best interests of Lessor justify such action. Applications for approval of a transfer under this paragraph must comply with the regulations and must be filed within ninety days after the date of final execution of the instrument of transfer. Where a transfer is made of all or a part of Lessee's interest in and to a portion of the acreage in said land the assigned acreage shall, at the option of Lessor, or may upon request of the transferee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

32. UNITIZATION. Whenever determined and certified by Lessor to be necessary or advisable in the public interest for the purpose of properly conserving the natural resources of any oil or gas pool, field or like area or any part thereof, which includes or underlies said land or any part thereof. Lessee may unite with other Lessees of Lessor or with others owning or operating lands not belonging to Lessor including lands belonging to the United States and with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the development or operation of the pool or field or like area or part thereof. Lessee shall within thirty days after demand by Lessor subscribe to such a cooperative or unit agreement, which agreement shall be reasonable and shall adequately protect all parties in interest including Lessor. Lessor may with the consent of Lessee establish, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of this lease if committed to any such cooperative or unit agreement and may make such regulations with reference to this lease with the like consent of Lessee in connection with the institution and operation of any such cooperative or unit agreement as Lessor may determine to be necessary or proper to secure the proper protection of the public interest. If a portion of said land is committed to an approved or prescribed unit agreement, the committed acreage shall at the option of Lessor and may upon the request of Lessee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

33. SURRENDER. Lessee may at any time make and file with Lessor a written surrender of all rights under this lease or any portion thereof comprising one or more legal subdivisions or, with the consent of Lessor, of any separate and distinct Zone or geological horizon underlying said lands or such one or more legal subdivisions thereof. Such a surrender shall be effective as of the date of filing subject to the continued obligations of Lessee and his surety to make payment of all royalties theretofore accrued and to place all wells on the surrendered land or in the surrendered zones or horizons in condition satisfactory to Lessor for suspension or abandonment; thereupon, Lessee shall be released from all other obligations accrued or to accrue under this lease with respect to the surrendered lands, zones, or horizons.

34. DEFAULT; TERMINATION. Whenever Lessee fails to comply with any of the provisions of this lease other than the payment of rental and Lessee fails within sixty days after written notice of such default to commence to remedy and thereafter prosecute diligently operations to remedy such default, Lessor may cancel this lease if at that time there is no well on said land capable of producing oil or gas in paying quantities. If at such time there is on said land a well capable of producing oil or gas in paying quantities, this lease may be cancelled only by judicial proceedings. In the event of any cancellation under this paragraph, Lessee shall have the right to retain under this lease any and all drilling or producing wells as to which no default exists together with a parcel of land surrounding each such well or wells and such rights of way through said land as may be reasonably necessary to enable Lessee to drill and operate such retained well or wells.

35. EXCESS AREA. If for any reason said land includes more acreage than the maximum permitted under applicable laws and/or regulations, this lease shall not be void but the acreage included in said land shall be reduced to the permitted maximum. Whenever Lessor determines that this lease so exceeds the permitted acreage and notifies Lessee stating the amount of acreage that must be eliminated, Lessee may within sixty days after such notice surrender one or more legal subdivisions included in said lands comprising at least the amount of acreage that must be eliminated. If such a surrender is not filed within such sixty days Lessor may terminate this lease as to the acreage that must be eliminated by mailing notice of such termination to Lessee describing the parcel or parcels eliminated. Such a notice shall have the effect of terminating this lease as to the parcel or parcels described in such notice.

36. RIGHTS ON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion of said lands, Lessee shall have the privilege at any time within a period of six months thereafter, or such extension thereof as may be granted by Lessor, of removing from said land or portion thereof all machinery, equipment, tools, and materials other than improvements needed for producing wells. Any materials, tools, appliances, machinery, structures, and equipment subject to removal as above provided which are allowed to remain on said land or portion thereof shall become the property of Lessor upon expiration of such period; provided, that Lessee shall remove any and all of such properties when so directed by Lessor. Subject to the foregoing, Lessee shall deliver up said lands or such portion or portions thereof in good order and condition.

37. INTEREST IN LAND. It is the intention of the parties that the rights vested in Lessee by this lease shall constitute an interest in real property in said land.

38. LESSOR INTEREST. If Lessor owns a lesser interest in the oil and gas deposits in said land than the entire and undivided fee simple estate, then the royalties and rentals herein provided shall be paid Lessor only in the proportion which its interest bears to the whole and undivided fee.

39. CONDITIONAL LEASE. If all or a part of said land is land that has been selected by the Lessor under laws of the United States granting lands to Lessor, but such land has not been patented to Lessor by the United States, then this lease is a conditional lease as provided by law until such patent become effective. If for any reason such a selection is not finally approved or such a patent does not become effective, and rental, royalty or minimum royalty payments made to Lessor under this lease will not be refunded.

40. DRILLING OPERATIONS. As used in this lease "drilling operations" mean any work or actual operations undertaken or commenced in good faith for the purpose of carrying out any of the rights, privileges or duties of Lessee under this lease, followed diligently and in due course by the construction of a road or derrick and/or other necessary structures for the drilling of an oil or gas well, and by the actual operation of drilling in the ground. Any such work or operations preliminary to drilling in the ground may be undertaken either on said land or in the vicinity of said land in any order Lessee shall see fit.

40. (a) ACTUAL DRILLING. As used in this lease, "actual drilling" means any and all operations necessary or convenient to the drilling of a well in the ground after the first drilling or spudding with equipment of sufficient size and capacity to drill to the total depth proposed for the well.

41. RULES AND REGULATIONS. As used in this lease "regulations" mean the applicable and valid oil and gas leasing regulations of the Commissioner of the Department of Natural Resources in effect on the effective date of this lease unless otherwise specified.

42. INTERPRETATION. As used in this lease words which are defined in the regulations have the meaning assigned by such definition except where the context clearly requires a different meaning. The paragraph headings are not a part of this lease and are inserted only for convenience.

43. NOTICES. Any notice required or permitted under this lease shall be in writing and shall be given by registered or certified mail, return receipt requested, addressed as follows:

To Lessor:

Director, Division of Lands
State of Alaska
344 Sixth Avenue
Anchorage, Alaska

To Lessee:

SHELL OIL COMPANY
1008 WEST SIXTH STREET
LOS ANGELES 54, CALIFORNIA

Any such notice shall be deemed given when delivered to the foregoing address. Either party may change the address to which such notices are to be sent, by a notice given in accordance with this paragraph.

44. HEIRS AND ASSIGNS. Subject to the other provisions of this lease, the covenants, conditions, and agreements contained in this lease shall extend to and be binding upon the heirs, executors, administrators, successors, or assigns of Lessor and Lessee.

45. WILDLIFE STIPULATIONS. This lease is subject to such stipulations as are attached.

IN WITNESS WHEREOF the parties have executed this lease.

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.....
.....
.....
.....
LESSEE

STATE OF ALASKA

By NORRIS C. BAKKE, JR. Norris C. Bakke, Jr.
Minerals Officer
Title ..... LESSOR

THE UNITED STATES OF AMERICA }
STATE OF ALASKA } ss.

This certifies that on the 23rd day of August, 1962, before me, a notary public in and for the State of Alaska, duly commissioned and sworn, personally appeared NORRIS C. BAKKE JR. to me known and known to me to be the person described in and who executed the foregoing lease on behalf of the State of Alaska as ~~Director~~ of the Division of Lands, Department of Natural Resources, or his authorized agent. The said NORRIS C. BAKKE JR. executed said lease in my presence and, after being duly sworn according to law, stated to me under oath that he is the ~~Director~~ of the Division of Lands, Department of Natural Resources, or his authorized agent, and has authority pursuant to law to execute the foregoing lease as such ~~Director,~~ or authorized agent, on behalf of the State of Alaska, acting through the Division of Lands, Department of Natural Resources and that he executed the same freely and voluntarily as the free and voluntary act and deed of the said State of Alaska and for the Division of Lands, Department of Natural Resources.

WITNESS my hand and official seal of the day and year in this certificate above written.

John C. Bates
Notary Public in and for Alaska. My Commission expires 9-27-65

IN WITNESS WHEREOF the parties have executed this lease.

STANDARD OIL COMPANY OF CALIFORNIA

By Geo. R. Gaskill
Contract Agent

By E. Altansen
Assistant Secretary

RICHFIELD OIL CORPORATION

By E. H. Phillips
Assistant General Manager of Production Dept.

By A. Nelson
Assistant Secretary

SHELL OIL COMPANY

By A. E. Mohn
Attorney in Fact

LESSEE

AGO 801553

FORM NO. DL-1
(REVISED APRIL, 1961)

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

LEASE NO. ADL 17590

Competitive Oil and Gas Lease

THIS LEASE, dated the 1st day of March, 19 62, is made by and between the State of Alaska, acting by and through the Director of the Division of Lands, Department of Natural Resources or his authorized agent, hereinafter called "lessor", and SHELL OIL COMPANY, a Delaware corp., 1008 W. Sixth Street, Los Angeles 54, Calif., ADL-QF #3; STANDARD OIL COMPANY OF CALIFORNIA, a Delaware corp., 225 Bush Street, San Francisco 20, Calif., ADL-QF #2,; and RICHFIELD OIL CORPORATION, a Delaware corp., 555 S. Flower Street, Los Angeles 17, Calif., ADL-QF #4 hereinafter called "Lessee", whether one or more.

1. GRANT. For and in consideration of a cash bonus and the first year's rental, the receipt of which is hereby acknowledged, and of the rentals, royalties, covenants, and conditions herein contained on the part of the Lessee to be paid, kept and performed, and subject to the conditions and reservations herein contained, Lessor does hereby grant and lease unto Lessee, exclusively, without warranty, for the sole and only purposes of exploration, development, production, processing and marketing of oil, gas, and associated substances produced therewith, and of installing pipe lines and structures thereon to find, produce, save, store, treat, process, transport, take care of and market all such substances, and for drilling water wells and taking underground and surface water for use in its operations thereon, and for housing and boarding employees in its operation thereon, the following described tract of land in Alaska:

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containing 5120.00 acres, more or less, hereinafter called "said land".

For the purposes of this lease, said land contains 8 legal subdivisions, as shown on the plat of said land attached hereto, marked Exhibit A and by this reference made a part of this lease.

If said land is described above by protracted legal sudivisions, or by officially designated tract numbers, and Lessor hereafter causes said land to be surveyed under the public land rectangular system, the boundaries of said land shall be those established by such survey, when approved, subject, however, to the provisions of the regulations relating to such surveys.

2. "OIL AND GAS". "Oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced and saved in liquid form at the well by ordinary production methods. "Gas" means all natural gas and all hydrocarbons produced at the well not defined herein as oil. "Associated substances" means all substances produced in association with oil or gas and not defined herein as oil or gas.

3. TERM. This lease is issued for an initial primary term of five years from the date hereof, subject to extension as provided in Paragraph 4 hereof, and shall continue so long thereafter as oil and gas or either or any of them are produced in paying quantities from said land; provided, that this lease may be extended beyond its primary term as provided in Paragraph 5 hereof and shall not expire under the conditions set forth in Paragraphs 6, 7, and 8 hereof.

4. EXTENSION BY SUSPENSION OF OPERATIONS. If, prior to the expiration of the primary term, Lessor, in the interest of conservation, directs or assents to the suspension of all operations and production, if any, hereunder, the primary term will be extended by adding the period of suspension thereto.

5. EXTENSION BY UNIT PRODUCTION (a) This lease shall without application be extended beyond its primary term if upon or prior to the expiration date of such term the lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, production of oil or gas is had in paying quantities under the agreement, and a portion of such production is allocated to said land under the agreement. In such event this lease shall continue in effect so long as it remains subject to such agreement and action production under said agreement is allocated to said land; (b) The Commissioner may, in his discretion provide for the extension of the term of this lease, if such lease is on the expiration date thereof included in an approved unit plan or if it is included in a program of secondary recovery operation designed to bring about or restore production, provided, however, that if any lease or portion thereof is eliminated from such unit plan or recovery program, or if such unit plan or recovery program is terminated, then no such lease or portion thereof shall continue in full force and effect for ninety (90) days from the date of such elimination or termination and so long thereafter as drilling or redrilling operations are being conducted thereon and so long thereafter as oil or gas is produced in paying quantities.

6. EXTENSION BY DRILLING. (a) If production shall have been obtained in paying quantities during the primary term, and if, at the end of the primary term, or at any time prior to the end of the primary term, such production shall have ceased from any cause, or in the event production shall at any time or times after the expiration of the primary term cease from any cause, then this lease shall not terminate if the Lessee commences drilling or reworking operations (either in a well from which such production has ceased or in a new well) within sixty days after the cessation of production, and the lease shall remain in full force and effect so long as such operations are prosecuted with reasonable diligence or are suspended under Paragraph 27 hereof; and, if such drilling or reworking operations result in the production of oil or gas, the lease shall remain in full force and effect so long as oil or gas is produced therefrom in paying quantities; (b) if actual drilling has commenced on the expiration date of the primary terms of the lease and is continued with reasonable diligence, such operations to include redrilling, sidetracking or other means necessary to reach the originally proposed bottom hole location, the lease shall continue in full force and effect until ninety (90) days after such drilling had ceased and for so long thereafter as oil or gas is produced in paying quantities; (c) if all or part of the lands covered by the lease are lands that have been selected by Alaska under laws of the United States granting lands to Alaska and the conditional lease was issued thereon, the term of the lease shall be extended for a period equal to the period during which the lease was conditional.

7. EXTENSION BY SHUT-IN PRODUCTION. If, upon the expiration of the primary term or at any time or times thereafter, there is on said land a well capable of producing oil or gas in paying quantities, this lease shall not expire because Lessee fails to produce the same unless Lessor gives notice to Lessee allowing a reasonable time, which shall not be less than sixty days, after such notice to place the well on a producing status, and Lessee fails to do so; provided, that after such status is established such production shall continue on the said land unless and until suspension of production is allowed by Lessor.

8. EXTENSION BY SUSPENSION OF PRODUCTION. This lease shall not expire because of any suspension of operations in or upon or production from said land if such suspension is made under any order or with the consent of Lessor.

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9. RENTAL. This lease shall terminate on any anniversary date hereof prior to the completion on said land of a well capable of producing oil or gas in paying quantities, unless on or before said anniversary date Lessee shall pay or tender to Lessor as annual rental a sum equal to $1.00 per acre, or fraction thereof, then included in this lease, or unless such annual rental has been waived or suspended as provided in Paragraph 13 of this lease. If Lessor's office is not open for business on the anniversary date, the time for payment is extended to include the next day on which said office is open for business. Any rental paid for any one lease year shall be credited on any royalty for that year.

10. MINIMUM ROYALTY. Commencing with the lease year beginning on or after completion on said land of a well capable of producing oil or gas in paying quantities, Lessee shall pay Lessor, at the expiration of each lease year, in lieu of rental a minimum royalty equal to $1.00 per acre, or fraction thereof, then included in this lease, or the difference between the actual royalty paid on production during the year if less than $1.00 per acre and the prescribed minimum royalty.

11. ROYALTY ON PRODUCTION. Except for oil and gas used on said land for development and production or unavoidably lost, Lessee shall pay Lessor as royalty the following:

(a) On oil 12½ per cent in amount or value of the oil produced and saved and removed or sold from said land.

(b) On gas 12½ per cent in amount or value of the gas produced and saved and sold or used off said land or used for the extraction of natural gasoline or other products therefrom.

(c) On associated substances 12½ per cent in amount or value of such substances produced and saved and removed or sold from said lands.

12. REDUCTION OF ROYALTY RATES FOR DISCOVERY. If Lessee shall drill on said land and make the first discovery of oil or gas in commercial quantities in any geological structure, the royalty rate under this lease shall, instead of the rates prescribed in Paragraph 11, be five per cent for a period of ten years following the date of such discovery, and thereafter the royalty rates shall be those prescribed in Paragraph 11. If this lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, the five per cent royalty rate shall apply to all, but only, the production allocated to this lease under such agreement.

13. REDUCTION OF RENTAL AND ROYALTY. Rental or minimum royalty may be waived, suspended, or reduced, or royalty may be reduced on all of said land or any tract or portion thereof segregated for royalty purposes if Lessor finds that such relief is necessary for the purpose of encouraging the greatest ultimate recovery of oil or gas and is in the interest of conservation of natural resources and either that such relief is necessary in order to promote development or that the lease cannot be successfully operated under the terms provided herein.

14. ROYALTY IN KIND. Whenever, at the option of Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, Lessor elects to take its royalty in kind, Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon) to Lessor or to such individual, firm, or corporation as Lessor may designate all royalty oil and/or gas produced and saved from said land. Such oil and/or gas shall be in good and merchantable condition. Lessee shall, if necessary, furnish storage for royalty oil free of charge for thirty days after the end of the calendar month in which the oil is produced from said land; provided, that Lessee shall not be held liable for loss or destruction of royalty oil and/or gas from causes beyond Lessee's reasonable control. Should Lessee dehydrate or clean the oil or gas produced from said land, Lessee shall be entitled to an allowance of the actual cost of dehydrating or cleaning said royalty oil or gas.

15. ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts or gross production.

16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or, (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

17. PAYMENTS. All payments to Lessor under this lease shall be made payable to the Department of Revenue of the State of Alaska and shall be tendered to Lessor at the place designated under Paragraph 43 for giving notices to Lessor.

18. OFFSET WELLS. Lessee shall drill such wells as a reasonably prudent operator would drill to protect Lessor adequately from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas should be produced in a well on other land not owned by Lessor or on which Lessor receives a lower rate of royalty than the royalty under this lease, which well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and such well shall produce oil or gas in paying quantities for a period of thirty consecutive days, and if, after notice to Lessee and an opportunity to be heard, Lessor finds that production from such well is draining lands then subject to this lease, Lessee shall within 120 days after written demand by Lessor begin in good faith and prosecute diligently drilling operations for an offset well on said land. In lieu of drilling any well required by this paragraph, Lessee may with Lessor's consent compensate Lessor in full each month for the estimated loss of royalty through drainage in the amount determined by lessor.

19. OTHER WELLS. This lease contemplates the reasonable development of said land for oil and gas as the facts may justify. Upon discovery of oil or gas in paying quantities on said land, Lessee shall drill such wells as a reasonably prudent operator would drill having due regard for the interests of Lessor as well as the interests of Lessee.

20. DILIGENCE; PREVENTION OF WASTE. Lessee shall exercise reasonable diligence in drilling, producing, and operating wells on said land unless consent to suspend operations temporarily is granted by Lessor; shall carry on all operations hereunder in a good and workmanlike manner in accordance with approved methods and practices, having due regard for the prevention of waste of oil and gas and the entrance of water to the oil and gas bearing sands or strata to the destruction or injury of such deposits and the preservation and conservation of the property for future productive operations; shall use reasonable care and all proper safeguards to prevent the pollution of water; shall plug securely in an approved manner any well before abandoningit; shall allow Lessor to inspect all operations at any time; shall carry out at Lessee's expense all reasonable orders and requirements of Lessor relative to the prevention of waste and the preservation of said land, and on failure of Lessee so to do, Lessor shall have the right together with any other recourse available to it to enter on said land to repair damage or prevent waste at Lessor's expense; and shall abide by and conform to valid applicable rules and regulations of the Alaska Oil and Gas Conservation Commission and the regulations of Lessor relating to the matters covered by this paragraph in effect on the effective date hereof or hereafter in effect if not inconsistent with any specific provisions of this lease.

21. WELL LOCATIONS. Lessee shall within five days after spudding in a well advise Lessor in writing of the location and date of spudding of said well.

22. APPROVAL OF PLANS. Lessee shall not place into actual operation any plan or method for the purpose of stimulating or increasing production on said land other than plans and methods in common use without first having obtained the written approval of Lessor.

23. LOGS AND RECORDS. An electric log or radioactive log, if taken, and a descriptive geologic sample log, if taken, and a record of all tests run for each well drilled on said land, together with a plat showing the exact location of each such well, shall be filed with Lessor within thirty (30) days after such well has been completed, suspended, or abandoned. Any and all information filed by Lessee with Lessor in connection with this lease shall be available at all times for the confidential use of Lessor for the purpose of enforcing compliance with the terms, covenants, and conditions of this lease and the regulations of the Lessor but shall not be open for inspection by any person other than officers, or employees of Lessor and persons performing any function or work assigned to them by Lessor for a period of twenty four (24) months after the thirty (30) day filing period, except upon written consent of Lessee. Notwithstanding any other provision hereof, said information may be disclosed to any person where such disclosure is reasonably necessary for the administration of the functions, responsibilities, and duties vested by law in the Commissioner of the Department of Natural Resources or in the Division of Lands or the Director thereof. Including but not limited to functions, responsibilities, and duties arising in connection with any litigation or administrative adjudication relating to this lease or to the rights, duties, and obligations arising hereunder.

24. RECORDS. Lessee shall keep and have in its possession books and records showing the production and disposition of all oil and gas produced from said land and shall permit Lessor or its agents at all reasonable hours to examine the same. Such records and reports of production shall be based upon such methods and techniques as shall insure the most accurate figures reasonably available without requiring the Lessee to provide separate tankage for each well.

25. DAMAGES. Sect. 2 of Article VII of the Alaska Land Act, Chapt. 169, S.L.A., 1959, as amended, provides in part that no rights under reservations contained in certain leases or grants of Alaska land shall be exercised by Lessor or its Lessee until provision has been made to pay to the owner of the land upon which the reserved rights are sought to be exercised full payment for all damages sustained by said owner by reason of entering upon said land; provided, that if said owner for any cause whatever refuses or neglects to settle said damage Lessor or its Lessee shall have the right to institute such legal proceedings in a court of competent jurisdiction wherein the land is situated as may be necessary to determine the damage which the owner of such land may suffer. Lessee hereby agrees to pay any damage that may become payable under said statutory provisions and to indemnify Lessor and hold it harmless from and against any claims, demands, liabilities, and expenses arising from or in connection with such damage. The furnishing of a bond in compliance with this lease will be regarded by Lessor as a sufficient provision for the payment of all damage that may become payable under said statutory provisions.

26. BONDS.

(a) Lessee shall maintain the bond furnished prior to the issuance of this lease in an amount equal to at least $2.00 per acre or fraction thereof contained in said land but not less than $1,000.00.

(b) Before beginning drilling operations on said land Lessee must have furnished and shall maintain a bond in an amount of at least $5,000.00.

(c) Lessee may, in lieu of the foregoing, furnish and maintain a statewide bond in the amount of $100,000.00

(d) Lessor may, after notice to Lessee and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified above in this paragraph where such greater amount is justified by the nature of the surface and its uses and improvements in the vicinity of said land and the degree of the risks involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph but will be considered by Lessor in determining the need for and the amount of any additional bond under this subparagraph.

(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

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(d) Lessor may, after notice to Lessee and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified above in this paragraph where such greater amount is justified by the nature of the surface and its uses and improvements in the vicinity of said land and the degree of the risks involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph but will be considered by Lessor in determining the need for and the amount of any additional bond under this subparagraph.

(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

27. ACTS OF GOD. Should Lessee be prevented from complying with any expressed or implied covenant of this lease, from conducting drilling operations thereon, or from producing or marketing oil or gas from said land after efforts made in good faith, by reason of war, riots, acts of God, severe weather in the area of said land, acts of governmental authorities, failure or lack of adequate transportation facilities, or any other cause beyond Lessee's reasonable control whether similar to those enumerated or not, then while so prevented and for a reasonable time thereafter within which to resume operations, Lessee's obligation to comply with such covenant shall be suspended and Lessee shall not be liable for damages for failure to comply therewith. If drilling or reworking operations are suspended by virtue of this paragraph and the prosecution of such operations would have had the effect of preventing the expiration or termination of this lease, then this lease shall not terminate during the period which the obligation to perform such operations is suspended under this paragraph; provided, however, that nothing in this paragraph shall be construed to suspend the payment of rentals or of minimum royalties.

28. SUSPENSION. Lessor may from time to time direct or assent to the suspension of production or other operations or both under this lease if such action is necessary or justified in the interest of conservation.

29. RESERVATIONS. Lessor reserves the right to dispose of the surface of said land to others subject to this lease, and the right to authorize others by grant, lease, or permit subject to this lease and under such conditions as will prevent unnecessary or unreasonable interference with the rights of Lessee and operations under this lease, to enter upon and use said land:

(a) To explore for oil or gas by geological or geophysical means including the drilling of shallow core holes or stratigraphic tests to a depth of not more than 1,000 feet.

(b) To explore for, develop and remove natural resources other than oil, gas, and associated substances on or from said land.

(c) For nonexclusive easements and rights of way for any lawful purpose including shafts and tunnels necessary or appropriate for the working of said land or other lands for natural resources other than oil, gas or associated substances.

(d) For well sites and well bores of wells drilled from or through said land to explore for or produce oil, gas, and associated substances in and from other lands.

(e) For any other purpose now or hereafter authorized by law and not inconsistent with the rights of Lessee under this lease.

30. UNDERGROUND STORAGE. This lease does not authorize the subsurface storage of oil or gas except as a necessary incident to recycling pressure maintenance, repressuring, or other similar operations designed to increase the ultimate recovery of oil or gas or prevent the waste of oil or gas produced from said land or from any unit area of which the said land is a part. Lessor reserves the right to authorize the subsurface storage of oil or gas in said land by Lessee or by others in order to avoid waste or to promote conservation of natural resources and upon such conditions as will prevent unnecessary or unreasonable interference with the rights and operations of Lessee under this lease, including conditions prohibiting the storage of oil or gas without the consent of Lessee in any reservoir covered by this lease capable of producing oil or gas in paying quantities.

31. ASSIGNMENTS. This lease or any undivided interest herein may with the approval of Lessor be assigned or subleased as to said land or any one or more legal subdivisions included therein, or any separate and distinct zone or geological horizon underlying said land or such one or more legal subdivisions, to any person or persons qualified to hold a lease. No transfer of any interest in this lease including assignments of working or royalty interests and operating agreements and subleases shall be binding upon Lessor unless approved by Lessor. Lessee shall remain liable for all obligations under this lease accruing prior to the approval of such transfer. Approval of transfer of this lease or an interest therein will not be denied except (1) for failure to comply with the regulations, (2) in the discretion of Lessor, where the transfer covers any distinct zone or geological horizon, or (3) where Lessor determines that the best interests of Lessor justify such action. Applications for approval of a transfer under this paragraph must comply with the regulations and must be filed within ninety days after the date of final execution of the instrument of transfer. Where a transfer is made of all or a part of Lessee's interest in and to a portion of the acreage in said land the assigned acreage shall, at the option of Lessor, or may upon request of the transferee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

32. UNITIZATION. Whenever determined and certified by Lessor to be necessary or advisable in the public interest for the purpose of properly conserving the natural resources of any oil or gas pool, field or like area or any part thereof, which includes or underlies said land or any part thereof, Lessee may unite with other Lessees of Lessor or with others owning or operating lands not belonging to Lessor including lands belonging to the United States and with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the development or operation of the pool or field or like area or part thereof. Lessee shall within thirty days after demand by Lessor subscribe to such a cooperative or unit agreement, which agreement shall be reasonable and shall adequately protect all parties in interest including Lessor. Lessor may with the consent of Lessee establish, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of this lease if committed to any such cooperative or unit agreement and may make such regulations with reference to this lease with the like consent of Lessee in connection with the institution and operation of any such cooperative or unit agreement as Lessor may determine to be necessary or proper to secure the proper protection of the public interest. If a portion of said land is committed to an approved or prescribed unit agreement, the committed acreage shall at the option of Lessor and may upon the request of Lessee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

33. SURRENDER. Lessee may at any time make and file with Lessor a written surrender of all rights under this lease or any portion thereof comprising one or more legal subdivisions or, with the consent of Lessor, of any separate and distinct Zone or geological horizon underlying said lands or such one or more legal subdivisions thereof. Such a surrender shall be effective as of the date of filing subject to the continued obligations of Lessee and his surety to make payment of all royalties theretofore accrued and to place all wells on the surrendered land or in the surrendered zones or horizons in condition satisfactory to Lessor for suspension or abandonment; thereupon, Lessee shall be released from all other obligations accrued or to accrue under this lease with respect to the surrendered lands, zones, or horizons.

34. DEFAULT; TERMINATION. Whenever Lessee fails to comply with any of the provisions of this lease other than the payment of rental and Lessee fails within sixty days after written notice of such default to commence to remedy and thereafter prosecute diligently operations to remedy such default, Lessor may cancel this lease if at that time there is no well on said land capable of producing oil or gas in paying quantities. If at such time there is on said land a well capable of producing oil or gas in paying quantities, this lease may be cancelled only by judicial proceedings. In the event of any cancellation under this paragraph, Lessee shall have the right to retain under this lease any and all drilling or producing wells as to which no default exists together with a parcel of land surrounding each such well wells and such rights of way through said land as may be reasonably necessary to enable Lessee to drill and operate ch retained well or wells.

35. EXCESS AREA. If for any reason said land includes more acreage than the maximum permitted under apcable laws and/or regulations, this lease shall not be void but the acreage included in said land shall be reduced to he permitted maximum. Whenever Lessor determines that this lease so exceeds the permitted acreage and notifies Lessee stating the amount of acreage that must be eliminated, Lessee may within sixty days after such notice surrender ne or more legal subdivisions included in said lands comprising at least the amount of acreage that must be eliminated. f such a surrender is not filed within such sixty days Lessor may terminate this lease as to the acreage that must be elimnated by mailing notice of such termination to Lessee describing the parcel or parcels eliminated. Such a notice shall have the effect of terminating this lease as to the parcel or parcels described in such notice.

36. RIGHTS ON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion of said lands, Lessee shall have the privilege at any time within a period of six months thereafter, or such extension thereof as may be granted by Lessor, of removing from said land or portion thereof all machinery, equipment, tools, and materials other than improvements needed for producing wells. Any materials, tools, appliances, machinery, structures, and equipment subject to removal as above provided which are allowed to remain on said land or portion thereof shall become the property of Lessor upon expiration of such period; provided, that Lessee shall remove any and all of such properties when so directed by Lessor. Subject to the foregoing, Lessee shall deliver up said lands or such portion or portions thereof in good order and condition.

37. INTEREST IN LAND. It is the intention of the parties that the rights vested in Lessee by this lease shall constitute an interest in real property in said land.

38. LESSOR INTEREST. If Lessor owns a lesser interest in the oil and gas deposits in said land than the entire and undivided fee simple estate, then the royalties and rentals herein provided shall be paid Lessor only in the proportion which its interest bears to the whole and undivided fee.

39. CONDITIONAL LEASE. If all or a part of said land is land that has been selected by the Lessor under laws of the United States granting lands to Lessor, but such land has not been patented to Lessor by the United States, then this lease is a conditional lease as provided by law until such patent become effective. If for any reason such a selection is not finally approved or such a patent does not become effective, and rental, royalty or minimum royalty payments made to Lessor under this lease will not be refunded.

40. DRILLING OPERATIONS. As used in this lease "drilling operations" mean any work or actual operations undertaken or commenced in good faith for the purpose of carrying out any of the rights, privileges or duties of Lessee under this lease, followed diligently and in due course by the construction of a road or derrick and/or other necessary structures for the drilling of an oil or gas well, and by the actual operation of drilling in the ground. Any such work or operations preliminary to drilling in the ground may be undertaken either on said land or in the vicinity of said land in any order Lessee shall see fit.

40. (a) ACTUAL DRILLING. As used in this lease, "actual drilling" means any and all operations necessary or convenient to the drilling of a well in the ground after the first drilling or spudding with equipment of sufficient size and capacity to drill to the total depth proposed for the well.

41. RULES AND REGULATIONS. As used in this lease "regulations" mean the applicable and valid oil and gas leasing regulations of the Commissioner of the Department of Natural Resources in effect on the effective date of this lease unless otherwise specified.

42. INTERPRETATION. As used in this lease words which are defined in the regulations have the meaning assigned by such definition except where the context clearly requires a different meaning. The paragraph headings are not a part of this lease and are inserted only for convenience.

43. NOTICES. Any notice required or permitted under this lease shall be in writing and shall be given by registered or certified mail, return receipt requested, addressed as follows:

To Lessor:

Director, Division of Lands
State of Alaska
344 Sixth Avenue
Anchorage, Alaska

To Lessee:

SHELL OIL COMPANY
1008 W. SIXTH STREET
LOS ANGELES 54, CALIFORNIA

Any such notice shall be deemed given when delivered to the foregoing address. Either party may change the address to which such notices are to be sent, by a notice given in accordance with this paragraph.

44. HEIRS AND ASSIGNS. Subject to the other provisions of this lease, the covenants, conditions, and agreements contained in this lease shall extend to and be binding upon the heirs, executors, administrators, successors, or assigns of Lessor and Lessee.

45. WILDLIFE STIPULATIONS. This lease is subject to such stipulations as are attached.

IN WITNESS WHEREOF the parties have executed this lease.

.....
.....
.....
.....
.....
LESSEE

STATE OF ALASKA

By Pearl Gingerich

Title Mineral Leasing Officer LESSOR

THE UNITED STATES OF AMERICA)
) ss.
STATE OF ALASKA)

This certifies that on the 11th day of February, 19 65 before me, a notary public in and for the State of Alaska, duly commissioned and sworn, personally appeared Pearl Gingerich, to me known and known to me to be the person described in and who executed the foregoing lease on behalf of the State of Alaska as Director of the Division of Lands, Department of Natural Resources, or his authorized agent. The said Pearl Gingerich executed said lease in my presence and, after being duly sworn according to law, stated to me under oath that he is the Director of the Division of Lands, Department of Natural Resources, or his authorized agent, and has authority pursuant to law to execute the foregoing lease as such Director, or authorized agent, on behalf of the State of Alaska, acting through the Division of Lands, Department of Natural Resources and that he executed the same freely and voluntarily as the free and voluntary act and deed of the said State of Alaska and for the Division of Lands, Department of Natural Resources.

WITNESS my hand and official seal the day and year in this certificate above written

John Malaee Notary Public in and for Alaska. My Commission expires 9-27-65

AGO 801557

State of California) ss
City and County of San Francisco)

On this 15th day of December, in the year of our Lord One Thousand Nine Hundred and Sixty One before me, Edmond Lee Kelly, a Notary Public in and for said City and County and State, residing therein, duly commissioned and sworn, personally appeared GEO. D. ENGLISH and J. P. BOWMAN known to me to be the CONTRACT AGENT and ASSISTANT SECRETARY, respectively of STANDARD OIL COMPANY OF CALIFORNIA the Corporation described in and that executed the within instrument, and also known to me to be the persons who executed it on behalf of the said Corporation therein named, and they acknowledged to me that such Corporation executed the same.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal, at my office in the City and County and State aforesaid the day and year in this certificate above written.

EDMOND LEE KELLY
[illegible]
My Commission Expires Jan. 2[illegible], 1964
RESIDING AT SAN [illegible], CALIFORNIA

Edmond Lee Kelly 35
Notary Public in and for said City and County of San Francisco, State of California

[illegible] notice of such default to commence to remedy [illegible] diligently operations to remedy such default, Lessor may cancel this lease if at that time there is no well on said land capable of producing oil or gas in paying quantities. If at such time there is on said land a well capable of producing oil or gas in paying quantities, this lease may be cancelled only by judicial proceedings. In the event of any cancellation under this paragraph, Lessee shall have the right to retain under this lease any and all drilling or producing wells as to which no default exists together with a parcel of land surrounding each such well

STATE OF CALIFORNIA, } ss.
COUNTY OF LOS ANGELES.

ON this 14th day of December, in the year 1961, before me, SUE M. MASON, a Notary Public in and for said County and State, personally appeared F. E. McPHILLIPS, known to me to be the Assistant General Manager of Production Dept., and R. G. NELSON, known to me to be the Assistant Secretary of RICHFIELD OIL CORPORATION, the corporation that executed the within instrument, known to me to be the persons who executed the within instrument on behalf of the corporation therein named, and acknowledged to me that such corporation executed the same.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal the day and year in this certificate first above written.

My commission expires My Commission Expires May 4, 1964

Sue M. Mason
Notary Public in and for said County and State.

ACK ROC CORP
ROC FORM 2529
PRTD. IN U.S.A. 6-61

SUE M. MASON

STATE OF CALIFORNIA
ss.
COUNTY OF LOS ANGELES

This certifies that on the 13th day of December, 1961, personally appeared before me, the undersigned, a notary public in and for said County and State, residing therein, S. F. BOWLBY, a Vice President of Shell Oil Company, the corporation described in and which executed the foregoing instrument, and said S. F. BOWLBY acknowledged to me that such corporation executed the same freely and voluntarily, for the uses and purposes therein mentioned.

WITNESS my hand and official seal the day and year in this certificate first above written.

Mildred M. Crawford
Mildred M. Crawford Notary Public in and for said County and State

My Commission expires December 11, 1963

IN WITNESS WHEREOF the parties have executed this lease.

SHELL OIL COMPANY
By [signature] Vice President
Attest by [signature], Assistant Secretary

RICHFIELD OIL CORPORATION
By F. E. McPhillips
Assistant General Manager of Production Dept.
By [signature]
Assistant Secretary

STANDARD OIL COMPANY OF CALIFORNIA
By Geo. D. English CONTRACT AGENT
By J. P. Bowman ASSISTANT SECRETARY

LESSEE

AGO 801558

FORM NO. DL-1
(REVISED APRIL, 1961)

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

LEASE NO. ADL 18719

Competitive Oil and Gas Lease

THIS LEASE, dated the 1st day of September, 19 62, is made by and between the State of Alaska, acting by and through the Director of the Division of Lands, Department of Natural Resources or his authorized agent, hereinafter called "lessor", and

Pan American Petroleum Corporation

hereinafter called "Lessee", whether one or more.

1. GRANT For and in consideration of a cash bonus and the first year's rental, the receipt of which is hereby acknowledged, and of the rentals, royalties, covenants, and conditions herein contained on the part of the Lessee to be paid, kept and performed, and subject to the conditions and reservations herein contained, Lessor does hereby grant and lease unto Lessee, exclusively, without warranty, for the sole and only purposes of exploration, development, production, processing and marketing of oil, gas, and associated substances produced therewith, and of installing pipe lines and structures thereon to find, produce, save, store, treat, process, transport, take care of and market all such substances, and for drilling water wells and taking underground and surface water for use in its operations thereon, and for housing and boarding employees in its operation thereon, the following described tract of land in Alaska:

S-13-6-28

containing 5120 acres, more or less, hereinafter called "said land".

For the purposes of this lease, said land contains 8 legal subdivisions, as shown on the plat of said land attached hereto, marked Exhibit A and by this reference made a part of this lease.

If said land is described above by protracted legal sudivisions, or by officially designated tract numbers, and Lessor hereafter causes said land to be surveyed under the public land rectangular system, the boundaries of said land shall be those established by such survey, when approved, subject, however, to the provisions of the regulations relating to such surveys.

2. "OIL AND GAS". "Oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced and saved in liquid form at the well by ordinary production methods. "Gas" means all natural gas and all hydrocarbons produced at the well not defined herein as oil. "Associated substances" means all substances produced in association with oil or gas and not defined herein as oil or gas.

3. TERM. This lease is issued for an initial primary term of five years from the date hereof, subject to extension as provided in Paragraph 4 hereof, and shall continue so long thereafter as oil and gas or either or any of them are produced in paying quantities from said land; provided, that this lease may be extended beyond its primary term as provided in Paragraph 5 hereof and shall not expire under the conditions set forth in Paragraphs 6, 7, and 8 hereof.

4. EXTENSION BY SUSPENSION OF OPERATIONS. If, prior to the expiration of the primary term, Lessor, in the interest of conservation, directs or assents to the suspension of all operations and production, if any, hereunder, the primary term will be extended by adding the period of suspension thereto.

5. EXTENSION BY UNIT PRODUCTION (a) This lease shall without application be extended beyond its primary term if upon or prior to the expiration date of such term the lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, production of oil or gas is had in paying quantities under the agreement, and a portion of such production is allocated to said land under the agreement. In such event this lease shall continue in effect so long as it remains subject to such agreement and action production under said agreement is allocated to said land; (b) The Commissioner may, in his discretion provide for the extension of the term of this lease, if such lease is on the expiration date thereof included in an approved unit plan or if it is included in a program of secondary recovery operation designed to bring about or restore production, provided, however, that if any lease or portion thereof is eliminated from such unit plan or recovery program, or if such unit plan or recovery program is terminated, then no such lease or portion thereof shall continue in full force and effect for ninety (90) days from the date of such elimination or termination and so long thereafter as drilling or redrilling operations are being conducted thereon and so long thereafter as oil or gas is produced in paying quantities.

6. EXTENSION BY DRILLING. (a) If production shall have been obtained in paying quantities during the primary term, and if, at the end of the primary term, or at any time prior to the end of the primary term, such production shall have ceased from any cause, or in the event production shall at any time or times after the expiration of the primary term cease from any cause, then this lease shall not terminate if the Lessee commences drilling or reworking operations (either in a well from which such production has ceased or in a new well) within sixty days after the cessation of production, and the lease shall remain in full force and effect so long as such operations are prosecuted with reasonable diligence or are suspended under Paragraph 27 hereof; and, if such drilling or reworking operations result in the production of oil or gas, the lease shall remain in full force and effect so long as oil or gas is produced therefrom in paying quantities; (b) if actual drilling has commenced on the expiration date of the primary terms of the lease and is continued with reasonable diligence, such operations to include redrilling, sidetracking or other means necessary to reach the originally proposed bottom hole location, the lease shall continue in full force and effect until ninety (90) days after such drilling had ceased and for so long thereafter as oil or gas is produced in paying quantities; (c) if all or part of the lands covered by the lease are lands that have been selected by Alaska under laws of the United States granting lands to Alaska and the conditional lease was issued thereon, the term of the lease shall be extended for a period equal to the period during which the lease was conditional.

7. EXTENSION BY SHUT-IN PRODUCTION. If, upon the expiration of the primary term or at any time or times thereafter, there is on said land a well capable of producing oil or gas in paying quantities, this lease shall not expire because Lessee fails to produce the same unless Lessor gives notice to Lessee allowing a reasonable time, which shall not be less than sixty days, after such notice to place the well on a producing status, and Lessee fails to do so; provided, that after such status is established such production shall continue on the said land unless and until suspension of production is allowed by Lessor.

8. EXTENSION BY SUSPENSION OF PRODUCTION. This lease shall not expire because of any suspension of operations in or upon or production from said land if such suspension is made under any order or with the consent of Lessor.

9. RENTAL. This lease shall terminate on any anniversary date hereof prior to the completion on said land of a well capable of producing oil or gas in paying quantities, unless on or before said anniversary date Lessee shall pay or tender to Lessor as annual rental a sum equal to $1.00 per acre, or fraction thereof, then included in this lease, or unless such annual rental has been waived or suspended as provided in Paragraph 13 of this lease. If Lessor's office is not open for business on the anniversary date, the time for payment is extended to include the next day on which said office is open for business. Any rental paid for any one lease year shall be credited on any royalty for that year.

10. MINIMUM ROYALTY. Commencing with the lease year beginning on or after completion on said land of a well capable of producing oil or gas in paying quantities, Lessee shall pay Lessor, at the expiration of each lease year, in lieu of rental a minimum royalty equal to $1.00 per acre, or fraction thereof, then included in this lease, or the difference between the actual royalty paid on production during the year if less than $1.00 per acre and the prescribed minimum royalty.

11. ROYALTY ON PRODUCTION. Except for oil and gas used on said land for development and production or unavoidably lost, Lessee shall pay Lessor as royalty the following:

(a) On oil 12½ per cent in amount or value of the oil produced and saved and removed or sold from said land.

(b) On gas 12½ per cent in amount or value of the gas produced and saved and sold or used off said land or used for the extraction of natural gasoline or other products therefrom.

(c) On associated substances 12½ per cent in amount or value of such substances produced and saved and removed or sold from said lands.

12. REDUCTION OF ROYALTY RATES FOR DISCOVERY. If Lessee shall drill on said land and make the first discovery of oil or gas in commercial quantities in any geological structure, the royalty rate under this lease shall, instead of the rates prescribed in Paragraph 11, be five per cent for a period of ten years following the date of such discovery, and thereafter the royalty rates shall be those prescribed in Paragraph 11. If this lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, the five per cent royalty rate shall apply to all, but only, the production allocated to this lease under such agreement.

13. REDUCTION OF RENTAL AND ROYALTY. Rental or minimum royalty may be waived, suspended, or reduced, or royalty may be reduced on all of said land or any tract or portion thereof segregated for royalty purposes if Lessor finds that such relief is necessary for the purpose of encouraging the greatest ultimate recovery of oil or gas and is in the interest of conservation of natural resources and either that such relief is necessary in order to promote development or that the lease cannot be successfully operated under the terms provided herein.

14. ROYALTY IN KIND. Whenever, at the option of Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, Lessor elects to take its royalty in kind, Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon) to Lessor or to such individual, firm, or corporation as Lessor may designate all royalty oil and/or gas produced and saved from said land. Such oil and/or gas shall be in good and merchantable condition. Lessee shall, if necessary, furnish storage for royalty oil free of charge for thirty days after the end of the calendar month in which the oil is produced from said land; provided, that Lessee shall not be held liable for loss or destruction of royalty oil and/or gas from causes beyond Lessee's reasonable control. Should Lessee dehydrate or clean the oil or gas produced from said land, Lessee shall be entitled to an allowance of the actual cost of dehydrating or cleaning said royalty oil or gas.

15. ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts or gross production.

16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or, (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

17. PAYMENTS. All payments to Lessor under this lease shall be made payable to the Department of Revenue of the State of Alaska and shall be tendered to Lessor at the place designated under Paragraph 43 for giving notices to Lessor.

18. OFFSET WELLS. Lessee shall drill such wells as a reasonably prudent operator would drill to protect Lessor adequately from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas should be produced in a well on other land not owned by Lessor or on which Lessor receives a lower rate of royalty than the royalty under this lease, which well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and such well shall produce oil or gas in paying quantities for a period of thirty consecutive days, and if, after notice to Lessee and an opportunity to be heard, Lessor finds that production from such well is draining lands then subject to this lease, Lessee shall within 120 days after written demand by Lessor begin in good faith and prosecute diligently drilling operations for an offset well on said land. In lieu of drilling any well required by this paragraph, Lessee may with Lessor's consent compensate Lessor in full each month for the estimated loss of royalty through drainage in the amount determined by lessor.

19. OTHER WELLS. This lease contemplates the reasonable development of said land for oil and gas as the facts may justify. Upon discovery of oil or gas in paying quantities on said land, Lessee shall drill such wells as a reasonably prudent operator would drill having due regard for the interests of Lessor as well as the interests of Lessee.

20. DILIGENCE; PREVENTION OF WASTE. Lessee shall exercise reasonable diligence in drilling, producing, and operating wells on said land unless consent to suspend operations temporarily is granted by Lessor; shall carry on all operations hereunder in a good and workmanlike manner in accordance with approved methods and practices, having due regard for the prevention of waste of oil and gas and the entrance of water to the oil and gas bearing sands or strata to the destruction or injury of such deposits and the preservation and conservation of the property for future productive operations; shall use reasonable care and all proper safeguards to prevent the pollution of water; shall plug securely in an approved manner any well before abandoningit; shall allow Lessor to inspect all operations at any time; shall carry out at Lessee's expense all reasonable orders and requirements of Lessor relative to the prevention of waste and the preservation of said land, and on failure of Lessee so to do, Lessor shall have the right together with any other recourse available to it to enter on said land to repair damage or prevent waste at Lessor's expense; and shall abide by and conform to valid applicable rules and regulations of the Alaska Oil and Gas Conservation Commission and the regulations of Lessor relating to the matters covered by this paragraph in effect on the effective date hereof or hereafter in effect if not inconsistent with any specific provisions of this lease.

21. WELL LOCATIONS. Lessee shall within five days after spudding in a well advise Lessor in writing of the location and date of spudding of said well.

22. APPROVAL OF PLANS. Lessee shall not place into actual operation any plan or method for the purpose of stimulating or increasing production on said land other than plans and methods in common use without first having obtained the written approval of Lessor.

23. LOGS AND RECORDS. An electric log or radioactive log, if taken, and a descriptive geologic sample log, if taken, and a record of all tests run for each well drilled on said land, together with a plat showing the exact location of each such well, shall be filed with Lessor within thirty (30) days after such well has been completed, suspended, or abandoned. Any and all information filed by Lessee with Lessor in connection with this lease shall be available at all times for the confidential use of Lessor for the purpose of enforcing compliance with the terms, covenants, and conditions of this lease and the regulations of the Lessor but shall not be open for inspection by any person other than officers, or employees of Lessor and persons performing any function or work assigned to them by Lessor for a period of twenty four (24) months after the thirty (30) day filing period, except upon written consent of Lessee. Notwithstanding any other provision hereof, said information may be disclosed to any person where such disclosure is reasonably necessary for the administration of the functions, responsibilities, and duties vested by law in the Commissioner of the Department of Natural Resources or in the Division of Lands or the Director thereof. Including but not limited to functions, responsibilities, and duties arising in connection with any litigation or administrative adjudication relating to this lease or to the rights, duties, and obligations arising hereunder.

24. RECORDS. Lessee shall keep and have in its possession books and records showing the production and disposition of all oil and gas produced from said land and shall permit Lessor or its agents at all reasonable hours to examine the same. Such records and reports of production shall be based upon such methods and techniques as shall insure the most accurate figures reasonably available without requiring the Lessee to provide separate tankage for each well.

25. DAMAGES. Sect. 2 of Article VII of the Alaska Land Act, Chapt. 169, S.L.A., 1959, as amended, provides in part that no rights under reservations contained in certain leases or grants of Alaska land shall be exercised by Lessor or its Lessee until provision has been made to pay to the owner of the land upon which the reserved rights are sought to be exercised full payment for all damages sustained by said owner by reason of entering upon said land; provided, that if said owner for any cause whatever refuses or neglects to settle said damage Lessor or its Lessee shall have the right to institute such legal proceedings in a court of competent jurisdiction wherein the land is situated as may be necessary to determine the damage which the owner of such land may suffer. Lessee hereby agrees to pay any damage that may become payable under said statutory provisions and to indemnify Lessor and hold it harmless from and against any claims, demands, liabilities, and expenses arising from or in connection with such damage. The furnishing of a bond in compliance with this Lease will be regarded by Lessor as a sufficient provision for the payment of all damage that may become payable under said statutory provisions.

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26. BONDS.

(a) Lessee shall maintain the bond furnished prior to the issuance of this lease in an amount equal to at least $2.00 per acre or fraction thereof contained in said land but not less than $1,000.00.

(b) Before beginning drilling operations on said land Lessee must have furnished and shall maintain a bond in an amount of at least $5,000.00.

(c) Lessee may, in lieu of the foregoing, furnish and maintain a statewide bond in the amount of $100,000.00

(d) Lessor may, after notice to Lessee and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified above in this paragraph where such greater amount is justified by the nature of the surface and its uses and improvements in the vicinity of said land and the degree of the risks involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph but will be considered by Lessor in determining the need for and the amount of any additional bond under this subparagraph.

(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by [illegible] bond is furnished in accordance with the regulations, Lessee

and duties arising in connection with any litigation or administrative adjudication relating to this lease or to the rights, duties, and obligations arising hereunder.

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(d) Lessor may, after notice to Lessee and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified above in this paragraph where such greater amount is justified by the nature of the surface and its uses and improvements in the vicinity of said land and the degree of the risks involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph but will be considered by Lessor in determining the need for and the amount of any additional bond under this subparagraph.

(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

27. ACTS OF GOD. Should Lessee be prevented from complying with any expressed or implied covenant of this lease, from conducting drilling operations thereon, or from producing or marketing oil or gas from said land after efforts made in good faith, by reason of war, riots, acts of God, severe weather in the area of said land, acts of governmental authorities, failure or lack of adequate transportation facilities, or any other cause beyond Lessee's reasonable control whether similar to those enumerated or not, then while so prevented and for a reasonable time thereafter within which to resume operations, Lessee's obligation to comply with such covenant shall be suspended and Lessee shall not be liable for damages for failure to comply therewith. If drilling or reworking operations are suspended by virtue of this paragraph and the prosecution of such operations would have had the effect of preventing the expiration or termination of this lease, then this lease shall not terminate during the period which the obligation to perform such operations is suspended under this paragraph; provided, however, that nothing in this paragraph shall be construed to suspend the payment of rentals or of minimum royalties.

28. SUSPENSION. Lessor may from time to time direct or assent to the suspension of production or other operations or both under this lease if such action is necessary or justified in the interest of conservation.

29. RESERVATIONS. Lessor reserves the right to dispose of the surface of said land to others subject to this lease, and the right to authorize others by grant, lease, or permit subject to this lease and under such conditions as will prevent unnecessary or unreasonable interference with the rights of Lessee and operations under this lease, to enter upon and use said land:

(a) To explore for oil or gas by geological or geophysical means including the drilling of shallow core holes or stratigraphic tests to a depth of not more than 1,000 feet.

(b) To explore for, develop and remove natural resources other than oil, gas, and associated substances on or from said land.

(c) For nonexclusive easements and rights of way for any lawful purpose including shafts and tunnels necessary or appropriate for the working of said land or other lands for natural resources other than oil, gas or associated substances.

(d) For well sites and well bores of wells drilled from or through said land to explore for or produce oil, gas, and associated substances in and from other lands.

(e) For any other purpose now or hereafter authorized by law and not inconsistent with the rights of Lessee under this lease.

30. UNDERGROUND STORAGE. This lease does not authorize the subsurface storage of oil or gas except as a necessary incident to recycling pressure maintenance, repressuring, or other similar operations designed to increase the ultimate recovery of oil or gas or prevent the waste of oil or gas produced from said land or from any unit area of which the said land is a part. Lessor reserves the right to authorize the subsurface storage of oil or gas in said land by Lessee or by others in order to avoid waste or to promote conservation of natural resources and upon such conditions as will prevent unnecessary or unreasonable interference with the rights and operations of Lessee under this lease, including conditions prohibiting the storage of oil or gas without the consent of Lessee in any reservoir covered by this lease capable of producing oil or gas in paying quantities.

31. ASSIGNMENTS. This lease or any undivided interest herein may with the approval of Lessor be assigned or subleased as to said land or any one or more legal subdivisions included therein, or any separate and distinct zone or geological horizon underlying said land or such one or more legal subdivisions, to any person or persons qualified to hold a lease. No transfer of any interest in this lease including assignments of working or royalty interests and operating agreements and subleases shall be binding upon Lessor unless approved by Lessor. Lessee shall remain liable for all obligations under this lease accruing prior to the approval of such transfer. Approval of transfer of this lease or an interest therein will not be denied except (1) for failure to comply with the regulations, (2) in the discretion of Lessor, where the transfer covers any distinct zone or geological horizon, or (3) where Lessor determines that the best interests of Lessor justify such action. Applications for approval of a transfer under this paragraph must comply with the regulations and must be filed within ninety days after the date of final execution of the instrument of transfer. Where a transfer is made of all or a part of Lessee's interest in and to a portion of the acreage in said land the assigned acreage shall, at the option of Lessor, or may upon request of the transferee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

32. UNITIZATION. Whenever determined and certified by Lessor to be necessary or advisable in the public interest for the purpose of properly conserving the natural resources of any oil or gas pool, field or like area or any part thereof, which includes or underlies said land or any part thereof, Lessee may unite with other Lessees of Lessor or with others owning or operating lands not belonging to Lessor including lands belonging to the United States and with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the development or operation of the pool or field or like area or part thereof. Lessee shall within thirty days after demand by Lessor subscribe to such a cooperative or unit agreement, which agreement shall be reasonable and shall adequately protect all parties in interest including Lessor. Lessor may with the consent of Lessee establish, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of this lease if committed to any such cooperative or unit agreement and may make such regulations with reference to this lease with the like consent of Lessee in connection with the institution and operation of any such cooperative or unit agreement as Lessor may determine to be necessary or proper to secure the proper protection of the public interest. If a portion of said land is committed to an approved or prescribed unit agreement, the committed acreage shall at the option of Lessor and may upon the request of Lessee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

33. SURRENDER. Lessee may at any time make and file with Lessor a written surrender of all rights under this lease or any portion thereof comprising one or more legal subdivisions or, with the consent of Lessor, of any separate and distinct Zone or geological horizon underlying said lands or such one or more legal subdivisions thereof. Such a surrender shall be effective as of the date of filing subject to the continued obligations of Lessee and his surety to make payment of all royalties theretofore accrued and to place all wells on the surrendered land or in the surrendered zones or horizons in condition satisfactory to Lessor for suspension or abandonment; thereupon, Lessee shall be released from all other obligations accrued or to accrue under this lease with respect to the surrendered lands, zones, or horizons.

34. DEFAULT; TERMINATION. Whenever Lessee fails to comply with any of the provisions of this lease other than the payment of rental and Lessee fails within sixty days after written notice of such default to commence to remedy and thereafter prosecute diligently operations to remedy such default, Lessor may cancel this lease if at that time there is no well on said land capable of producing oil or gas in paying quantities. If at such time there is on said land a well capable of producing oil or gas in paying quantities, this lease may be cancelled only by judicial proceedings. In the event of any cancellation under this paragraph, Lessee shall have the right to retain under this lease any and all drilling or producing wells as to which no default exists together with a parcel of land surrounding each such well or wells and such rights of way through said land as may be reasonably necessary to enable Lessee to drill and operate such retained well or wells.

35. EXCESS AREA. If for any reason said land includes more acreage than the maximum permitted under applicable laws and/or regulations, this lease shall not be void but the acreage included in said land shall be reduced to the permitted maximum. Whenever Lessor determines that this lease so exceeds the permitted acreage and notifies Lessee stating the amount of acreage that must be eliminated, Lessee may within sixty days after such notice surrender one or more legal subdivisions included in said lands comprising at least the amount of acreage that must be eliminated. If such a surrender is not filed within such sixty days Lessor may terminate this lease as to the acreage that must be eliminated by mailing notice of such termination to Lessee describing the parcel or parcels eliminated. Such a notice shall have the effect of terminating this lease as to the parcel or parcels described in such notice.

36. RIGHTS ON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion of said lands, Lessee shall have the privilege at any time within a period of six months thereafter, or such extension thereof as may be granted by Lessor, of removing from said land or portion thereof all machinery, equipment, tools, and materials other than improvements needed for producing wells. Any materials, tools, appliances, machinery, structures, and equipment subject to removal as above provided which are allowed to remain on said land or portion thereof shall become the property of Lessor upon expiration of such period; provided, that Lessee shall remove any and all of such properties when so directed by Lessor. Subject to the foregoing, Lessee shall deliver up said lands or such portion or portions thereof in good order and condition.

37. INTEREST IN LAND. It is the intention of the parties that the rights vested in Lessee by this lease shall constitute an interest in real property in said land.

38. LESSOR INTEREST. If Lessor owns a lesser interest in the oil and gas deposits in said land than the entire and undivided fee simple estate, then the royalties and rentals herein provided shall be paid Lessor only in the proportion which its interest bears to the whole and undivided fee.

39. CONDITIONAL LEASE. If all or a part of said land is land that has been selected by the Lessor under laws of the United States granting lands to Lessor, but such land has not been patented to Lessor by the United States, then this lease is a conditional lease as provided by law until such patent become effective. If for any reason such a selection is not finally approved or such a patent does not become effective, and rental, royalty or minimum royalty payments made to Lessor under this lease will not be refunded.

40. DRILLING OPERATIONS. As used in this lease "drilling operations" mean any work or actual operations undertaken or commenced in good faith for the purpose of carrying out any of the rights, privileges or duties of Lessee under this lease, followed diligently and in due course by the construction of a road or derrick and/or other necessary structures for the drilling of an oil or gas well, and by the actual operation of drilling in the ground. Any such work or operations preliminary to drilling in the ground may be undertaken either on said land or in the vicinity of said land in any order Lessee shall see fit.

40. (a) ACTUAL DRILLING. As used in this lease, "actual drilling" means any and all operations necessary or convenient to the drilling of a well in the ground after the first drilling or spudding with equipment of sufficient size and capacity to drill to the total depth proposed for the well.

41. RULES AND REGULATIONS. As used in this lease "regulations" mean the applicable and valid oil and gas leasing regulations of the Commissioner of the Department of Natural Resources in effect on the effective date of this lease unless otherwise specified.

42. INTERPRETATION. As used in this lease words which are defined in the regulations have the meaning assigned by such definition except where the context clearly requires a different meaning. The paragraph headings are not a part of this lease and are inserted only for convenience.

43. NOTICES. Any notice required or permitted under this lease shall be in writing and shall be given by registered or certified mail, return receipt requested, addressed as follows:

To Lessor:

Director, Division of Lands
State of Alaska
344 Sixth Avenue
Anchorage, Alaska

To Lessee: Pan American Petroleum Corporation
P. O. Box 712
Anchorage, Alaska

Any such notice shall be deemed given when delivered to the foregoing address. Either party may change the address to which such notices are to be sent, by a notice given in accordance with this paragraph.

44. HEIRS AND ASSIGNS. Subject to the other provisions of this lease, the covenants, conditions, and agreements contained in this lease shall extend to and be binding upon the heirs, executors, administrators, successors, or assigns of Lessor and Lessee.

45. WILDLIFE STIPULATIONS. This lease is subject to such stipulations as are attached.

IN WITNESS WHEREOF the parties have executed this lease.

Pan American Petroleum Corporation

BY: Ross W. Lowry
Its Attorney-in-Fact
LESSEE

STATE OF ALASKA

By Norris C. Bakke, Jr.
Norris C. Bakke, Jr.
Title Minerals Officer LESSOR

THE UNITED STATES OF AMERICA)
STATE OF ALASKA) ss.

This certifies that on the 28th day of August, 1962, before me, a notary public in and for the State of Alaska, duly commissioned and sworn, personally appeared NORRIS C. BAKKE, JR., to me known and known to me to be the person described in and who executed the foregoing lease on behalf of the State of Alaska as Director of the Division of Lands, Department of Natural Resources, or his authorized agent. The said NORRIS C. BAKKE, JR. executed said lease in my presence and, after being duly sworn according to law, stated to me under oath that he is the Director of the Division of Lands, Department of Natural Resources, or his authorized agent, and has authority pursuant to law to execute the foregoing lease as such Director, or authorized agent, on behalf of the State of Alaska, acting through the Division of Lands, Department of Natural Resources and that he executed the same freely and voluntarily as the free and voluntary act and deed of the said State of Alaska and for the Division of Lands, Department of Natural Resources.

WITNESS my hand and official seal the day and year in this certificate above written.

John Kalas
Notary Public in and for Alaska. My Commission expires 9-27-65

AGO 801562

FORM NO. DL-1
(REVISED APRIL, 1961)

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

LEASE NO. ADL 17589

Competitive Oil and Gas Lease

THIS LEASE, dated the 1st day of February, 1962, is made by and between the State of Alaska, acting by and through the Director of the Division of Lands, Department of Natural Resources or his authorized agent, hereinafter called "lessor", and

Pan American Petroleum Corporation, P. O. Box 712, Anchorage, Alaska

hereinafter called "Lessee", whether one or more.

1. GRANT. For and in consideration of a cash bonus and the first year's rental, the receipt of which is hereby acknowledged, and of the rentals, royalties, covenants, and conditions herein contained on the part of the Lessee to be paid, kept and performed, and subject to the conditions and reservations herein contained, Lessor does hereby grant and lease unto Lessee, exclusively, without warranty, for the sole and only purposes of exploration, development, production, processing and marketing of oil, gas, and associated substances produced therewith, and of installing pipe lines and structures thereon to find, produce, save, store, treat, process, transport, take care of and market all such substances, and for drilling water wells and taking underground and surface water for use in its operations thereon, and for housing and boarding employees in its operation thereon, the following described tract of land in Alaska:

S-13-6-8

containing 5002 acres, more or less, hereinafter called "said land".

For the purposes of this lease, said land contains 8 legal subdivisions, as shown on the plat of said land attached hereto, marked Exhibit A and by this reference made a part of this lease.

If said land is described above by protracted legal sudivisions, or by officially designated tract numbers, and Lessor hereafter causes said land to be surveyed under the public land rectangular system, the boundaries of said land shall be those established by such survey, when approved, subject, however, to the provisions of the regulations relating to such surveys.

2. "OIL AND GAS". "Oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced and saved in liquid form at the well by ordinary production methods. "Gas" means all natural gas and all hydrocarbons produced at the well not defined herein as oil. "Associated substances" means all substances produced in association with oil or gas and not defined herein as oil or gas.

3. TERM. This lease is issued for an initial primary term of five years from the date hereof, subject to extension as provided in Paragraph 4 hereof, and shall continue so long thereafter as oil and gas or either or any of them are produced in paying quantities from said land; provided, that this lease may be extended beyond its primary term as provided in Paragraph 5 hereof and shall not expire under the conditions set forth in Paragraphs 6, 7, and 8 hereof.

4. EXTENSION BY SUSPENSION OF OPERATIONS. If, prior to the expiration of the primary term, Lessor, in the interest of conservation, directs or assents to the suspension of all operations and production, if any, hereunder, the primary term will be extended by adding the period of suspension thereto.

5. EXTENSION BY UNIT PRODUCTION (a) This lease shall without application be extended beyond its primary term if upon or prior to the expiration date of such term the lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, production of oil or gas is had in paying quantities under the agreement, and a portion of such production is allocated to said land under the agreement. In such event this lease shall continue in effect so long as it remains subject to such agreement and action production under said agreement is allocated to said land; (b) The Commissioner may, in his discretion provide for the extension of the term of this lease, if such lease is on the expiration date thereof included in an approved unit plan or if it is included in a program of secondary recovery operation designed to bring about or restore production, provided, however, that if any lease or portion thereof is eliminated from such unit plan or recovery program, or if such unit plan or recovery program is terminated, then no such lease or portion thereof shall continue in full force and effect for ninety (90) days from the date of such elimination or termination and so long thereafter as drilling or redrilling operations are being conducted thereon and so long thereafter as oil or gas is produced in paying quantities.

6. EXTENSION BY DRILLING. (a) If production shall have been obtained in paying quantities during the primary term, and if, at the end of the primary term, or at any time prior to the end of the primary term, such production shall have ceased from any cause, or in the event production shall at any time or times after the expiration of the primary term cease from any cause, then this lease shall not terminate if the Lessee commences drilling or reworking operations (either in a well from which such production has ceased or in a new well) within sixty days after the cessation of production, and the lease shall remain in full force and effect so long as such operations are prosecuted with reasonable diligence or are suspended under Paragraph 27 hereof; and, if such drilling or reworking operations result in the production of oil or gas, the lease shall remain in full force and effect so long as oil or gas is produced therefrom in paying quantities; (b) if actual drilling has commenced on the expiration date of the primary terms of the lease and is continued with reasonable diligence, such operations to include redrilling, sidetracking or other means necessary to reach the originally proposed bottom hole location, the lease shall continue in full force and effect until ninety (90) days after such drilling had ceased and for so long thereafter as oil or gas is produced in paying quantities; (c) if all or part of the lands covered by the lease are lands that have been selected by Alaska under laws of the United States granting lands to Alaska and the conditional lease was issued thereon, the term of the lease shall be extended for a period equal to the period during which the lease was conditional.

7. EXTENSION BY SHUT-IN PRODUCTION. If, upon the expiration of the primary term or at any time or times thereafter, there is on said land a well capable of producing oil or gas in paying quantities, this lease shall not expire because Lessee fails to produce the same unless Lessor gives notice to Lessee allowing a reasonable time, which shall not be less than sixty days, after such notice to place the well on a producing status, and Lessee fails to do so; provided, that after such status is established such production shall continue on the said land unless and until suspension of production is allowed by Lessor.

8. EXTENSION BY SUSPENSION OF PRODUCTION. This lease shall not expire because of any suspension of operations in or upon or production from said land if such suspension is made under any order or with the consent of Lessor.

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12N 9W
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9. RENTAL. This lease shall terminate on any anniversary date hereof prior to the completion on said land of a well capable of producing oil or gas in paying quantities, unless on or before said anniversary date Lessee shall pay or tender to Lessor as annual rental a sum equal to $1.00 per acre, or fraction thereof, then included in this lease, or unless such annual rental has been waived or suspended as provided in Paragraph 13 of this lease. If Lessor's office is not open for business on the anniversary date, the time for payment is extended to include the next day on which said office is open for business. Any rental paid for any one lease year shall be credited on any royalty for that year.

10. MINIMUM ROYALTY. Commencing with the lease year beginning on or after completion on said land of a well capable of producing oil or gas in paying quantities, Lessee shall pay Lessor, at the expiration of each lease year, in lieu of rental a minimum royalty equal to $1.00 per acre, or fraction thereof, then included in this lease, or the difference between the actual royalty paid on production during the year if less than $1.00 per acre and the prescribed minimum royalty.

11. ROYALTY ON PRODUCTION. Except for oil and gas used on said land for development and production or unavoidably lost, Lessee shall pay Lessor as royalty the following:

(a) On oil 12-1/2 per cent in amount or value of the oil produced and saved and removed or sold from said land.

(b) On gas 12-1/2 per cent in amount or value of the gas produced and saved and sold or used off said land or used for the extraction of natural gasoline or other products therefrom.

(c) On associated substances 12-1/2 per cent in amount or value of such substances produced and saved and removed or sold from said lands.

12. REDUCTION OF ROYALTY RATES FOR DISCOVERY. If Lessee shall drill on said land and make the first discovery of oil or gas in commercial quantities in any geological structure, the royalty rate under this lease shall, instead of the rates prescribed in Paragraph 11, be five per cent for a period of ten years following the date of such discovery, and thereafter the royalty rates shall be those prescribed in Paragraph 11. If this lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, the five per cent royalty rate shall apply to all, but only, the production allocated to this lease under such agreement.

13. REDUCTION OF RENTAL AND ROYALTY. Rental or minimum royalty may be waived, suspended, or reduced, or royalty may be reduced on all of said land or any tract or portion thereof segregated for royalty purposes if Lessor finds that such relief is necessary for the purpose of encouraging the greatest ultimate recovery of oil or gas and is in the interest of conservation of natural resources and either that such relief is necessary in order to promote development or that the lease cannot be successfully operated under the terms provided herein.

14. ROYALTY IN KIND. Whenever, at the option of Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, Lessor elects to take its royalty in kind, Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon) to Lessor or to such individual, firm, or corporation as Lessor may designate all royalty oil and/or gas produced and saved from said land. Such oil and/or gas shall be in good and merchantable condition. Lessee shall, if necessary, furnish storage for royalty oil free of charge for thirty days after the end of the calendar month in which the oil is produced from said land; provided, that Lessee shall not be held liable for loss or destruction of royalty oil and/or gas from causes beyond Lessee's reasonable control. Should Lessee dehydrate or clean the oil or gas produced from said land, Lessee shall be entitled to an allowance of the actual cost of dehydrating or cleaning said royalty oil or gas.

15. ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts or gross production.

16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or, (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

17. PAYMENTS. All payments to Lessor under this lease shall be made payable to the Department of Revenue of the State of Alaska and shall be tendered to Lessor at the place designated under Paragraph 43 for giving notices to Lessor.

18. OFFSET WELLS. Lessee shall drill such wells as a reasonably prudent operator would drill to protect Lessor adequately from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas should be produced in a well on other land not owned by Lessor or on which Lessor receives a lower rate of royalty than the royalty under this lease, which well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and such well shall produce oil or gas in paying quantities for a period of thirty consecutive days, and if, after notice to Lessee and an opportunity to be heard, Lessor finds that production from such well is draining lands then subject to this lease, Lessee shall within 120 days after written demand by Lessor begin in good faith and prosecute diligently drilling operations for an offset well on said land. In lieu of drilling any well required by this paragraph, Lessee may with Lessor's consent compensate Lessor in full each month for the estimated loss of royalty through drainage in the amount determined by lessor.

19. OTHER WELLS. This lease contemplates the reasonable development of said land for oil and gas as the facts may justify. Upon discovery of oil or gas in paying quantities on said land, Lessee shall drill such wells as a reasonably prudent operator would drill having due regard for the interests of Lessor as well as the interests of Lessee.

20. DILIGENCE; PREVENTION OF WASTE. Lessee shall exercise reasonable diligence in drilling, producing, and operating wells on said land unless consent to suspend operations temporarily is granted by Lessor; shall carry on all operations hereunder in a good and workmanlike manner in accordance with approved methods and practices, having due regard for the prevention of waste of oil and gas and the entrance of water to the oil and gas bearing sands or strata to the destruction or injury of such deposits and the preservation and conservation of the property for future productive operations; shall use reasonable care and all proper safeguards to prevent the pollution of water; shall plug securely in an approved manner any well before abandoningit; shall allow Lessor to inspect all operations at any time; shall carry out at Lessee's expense all reasonable orders and requirements of Lessor relative to the prevention of waste and the preservation of said land, and on failure of Lessee so to do, Lessor shall have the right together with any other recourse available to it to enter on said land to repair damage or prevent waste at Lessor's expense; and shall abide by and conform to valid applicable rules and regulations of the Alaska Oil and Gas Conservation Commission and the regulations of Lessor relating to the matters covered by this paragraph in effect on the effective date hereof or hereafter in effect if not inconsistent with any specific provisions of this lease.

21. WELL LOCATIONS. Lessee shall within five days after spudding in a well advise Lessor in writing of the location and date of spudding of said well.

22. APPROVAL OF PLANS. Lessee shall not place into actual operation any plan or method for the purpose of stimulating or increasing production on said land other than plans and methods in common use without first having obtained the written approval of Lessor.

23. LOGS AND RECORDS. An electric log or radioactive log, if taken, and a descriptive geologic sample log, if taken, and a record of all tests run for each well drilled on said land, together with a plat showing the exact location of each such well, shall be filed with Lessor within thirty (30) days after such well has been completed, suspended, or abandoned. Any and all information filed by Lessee with Lessor in connection with this lease shall be available at all times for the confidential use of Lessor for the purpose of enforcing compliance with the terms, covenants, and conditions of this lease and the regulations of the Lessor but shall not be open for inspection by any person other than officers, or employees of Lessor and persons performing any function or work assigned to them by Lessor for a period of twenty four (24) months after the thirty (30) day filing period, except upon written consent of Lessee. Notwithstanding any other provision hereof, said information may be disclosed to any person where such disclosure is reasonably necessary for the administration of the functions, responsibilities, and duties vested by law in the Commissioner of the Department of Natural Resources or in the Division of Lands or the Director thereof. Including but not limited to functions, responsibilities, and duties arising in connection with any litigation or administrative adjudication relating to this lease or to the rights, duties, and obligations arising hereunder.

24. RECORDS. Lessee shall keep and have in its possession books and records showing the production and disposition of all oil and gas produced from said land and shall permit Lessor or its agents at all reasonable hours to examine the same. Such records and reports of production shall be based upon such methods and techniques as shall insure the most accurate figures reasonably available without requiring the Lessee to provide separate tankage for each well.

25. DAMAGES. Sect. 2 of Article VII of the Alaska Land Act, Chapt. 169, S.L.A., 1959, as amended, provides in part that no rights under reservations contained in certain leases or grants of Alaska land shall be exercised by Lessor or its Lessee until provision has been made to pay to the owner of the land upon which the reserved rights are sought to be exercised full payment for all damages sustained by said owner by reason of entering upon said land; provided, that if said owner for any cause whatever refuses or neglects to settle said damages, Lessor or its Lessee shall have the right to institute such legal proceedings in a court of competent jurisdiction wherein the land is situated as may be necessary to determine the damage which the owner of such land may suffer. Lessee hereby agrees to pay any damage that may become payable under said statutory provisions and to indemnify Lessor and hold it harmless from and against any claims, demands, liabilities, and expenses arising from or in connection with such damage. The furnishing of a bond in compliance with this Lease will be regarded by Lessor as a sufficient provision for the payment of all damage that may become payable under said statutory provisions.

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26. BONDS.

(a) Lessee shall maintain the bond furnished prior to the issuance of this lease in an amount equal to at least $2.00 per acre or fraction thereof contained in said land but not less than $1,000.00.

(b) Before beginning drilling operations on said land Lessee must have furnished and shall maintain a bond in an amount of at least $5,000.00.

(c) Lessee may, in lieu of the foregoing, furnish and maintain a statewide bond in the amount of $100,000.00

(d) Lessor may, after notice to Lessee and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified above in this paragraph where such greater amount is justified by the nature of the surface and its uses and improvements in the vicinity of said land and the degree of the risks involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph but will be considered by Lessor in determining the need for and the amount of any additional bond under this subparagraph.

(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

27. ACTS OF GOD. Should Lessee be prevented from complying with any expressed or implied covenant of this

Lessee until provision has been made to pay to the owner of the land upon which the reserved rights are sought to be exercised full payment for all damages sustained by said owner by reason of entering upon said land; provided, that if said owner for any cause whatever refuses or neglects to settle said damages, Lessor or its Lessee shall have the right to institute such legal proceedings in a court of competent jurisdiction wherein the land is situated as may be necessary to determine the damage which the owner of such land may suffer. Lessee hereby agrees to pay any damage that may become payable under said statutory provisions and to indemnify Lessor and hold it harmless from and against any claims, demands, liabilities, and expenses arising from or in connection with such damage. The furnishing of a bond in compliance with this Lease will be regarded by Lessor as a sufficient provision for the payment of all damage that may become payable under said statutory provisions.

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(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

27. ACTS OF GOD. Should Lessee be prevented from complying with any expressed or implied covenant of this lease, from conducting drilling operations thereon, or from producing or marketing oil or gas from said land after efforts made in good faith, by reason of war, riots, acts of God, severe weather in the area of said land, acts of governmental authorities, failure or lack of adequate transportation facilities, or any other cause beyond Lessee's reasonable control whether similar to those enumerated or not, then while so prevented and for a reasonable time thereafter within which to resume operations, Lessee's obligation to comply with such covenant shall be suspended and Lessee shall not be liable for damages for failure to comply therewith. If drilling or reworking operations are suspended by virtue of this paragraph and the prosecution of such operations would have had the effect of preventing the expiration or termination of this lease, then this lease shall not terminate during the period which the obligation to perform such operations is suspended under this paragraph; provided, however, that nothing in this paragraph shall be construed to suspend the payment of rentals or of minimum royalties.

28. SUSPENSION. Lessor may from time to time direct or assent to the suspension of production or other operations or both under this lease if such action is necessary or justified in the interest of conservation.

29. RESERVATIONS. Lessor reserves the right to dispose of the surface of said land to others subject to this lease, and the right to authorize others by grant, lease, or permit subject to this lease and under such conditions as will prevent unnecessary or unreasonable interference with the rights of Lessee and operations under this lease, to enter upon and use said land:

(a) To explore for oil or gas by geological or geophysical means including the drilling of shallow core holes or stratigraphic tests to a depth of not more than 1,000 feet.

(b) To explore for, develop and remove natural resources other than oil, gas, and associated substances on or from said land.

(c) For nonexclusive easements and rights of way for any lawful purpose including shafts and tunnels necessary or appropriate for the working of said land or other lands for natural resources other than oil, gas or associated substances.

(d) For well sites and well bores of wells drilled from or through said land to explore for or produce oil, gas, and associated substances in and from other lands.

(e) For any other purpose now or hereafter authorized by law and not inconsistent with the rights of Lessee under this lease.

30. UNDERGROUND STORAGE. This lease does not authorize the subsurface storage of oil or gas except as a necessary incident to recycling pressure maintenance, repressuring, or other similar operations designed to increase the ultimate recovery of oil or gas or prevent the waste of oil or gas produced from said land or from any unit area of which the said land is a part. Lessor reserves the right to authorize the subsurface storage of oil or gas in said land by Lessee or by others in order to avoid waste or to promote conservation of natural resources and upon such conditions as will prevent unnecessary or unreasonable interference with the rights and operations of Lessee under this lease, including conditions prohibiting the storage of oil or gas without the consent of Lessee in any reservoir covered by this lease capable of producing oil or gas in paying quantities.

31. ASSIGNMENTS. This lease or any undivided interest herein may with the approval of Lessor be assigned or subleased as to said land or any one or more legal subdivisions included therein, or any separate and distinct zone or geological horizon underlying said land or such one or more legal subdivisions, to any person or persons qualified to hold a lease. No transfer of any interest in this lease including assignments of working or royalty interests and operating agreements and subleases shall be binding upon Lessor unless approved by Lessor. Lessee shall remain liable for all obligations under this lease accruing prior to the approval of such transfer. Approval of transfer of this lease or an interest therein will not be denied except (1) for failure to comply with the regulations, (2) in the discretion of Lessor, where the transfer covers any distinct zone or geological horizon, or (3) where Lessor determines that the best interests of Lessor justify such action. Applications for approval of a transfer under this paragraph must comply with the regulations and must be filed within ninety days after the date of final execution of the instrument of transfer. Where a transfer is made of all or a part of Lessee's interest in and to a portion of the acreage in said land the assigned acreage shall, at the option of Lessor, or may upon request of the transferee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

32. UNITIZATION. Whenever determined and certified by Lessor to be necessary or advisable in the public interest for the purpose of properly conserving the natural resources of any oil or gas pool, field or like area or any part thereof, which includes or underlies said land or any part thereof, Lessee may unite with other Lessees of Lessor or with others owning or operating lands not belonging to Lessor including lands belonging to the United States and with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the development or operation of the pool or field or like area or part thereof. Lessee shall within thirty days after demand by Lessor subscribe to such a cooperative or unit agreement, which agreement shall be reasonable and shall adequately protect all parties in interest including Lessor. Lessor may with the consent of Lessee establish, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of this lease if committed to any such cooperative or unit agreement and may make such regulations with reference to this lease with the like consent of Lessee in connection with the institution and operation of any such cooperative or unit agreement as Lessor may determine to be necessary or proper to secure the proper protection of the public interest. If a portion of said land is committed to an approved or prescribed unit agreement, the committed acreage shall at the option of Lessor and may upon the request of Lessee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

33. SURRENDER. Lessee may at any time make and file with Lessor a written surrender of all rights under this lease or any portion thereof comprising one or more legal subdivisions or, with the consent of Lessor, of any separate and distinct Zone or geological horizon underlying said lands or such one or more legal subdivisions thereof. Such a surrender shall be effective as of the date of filing subject to the continued obligations of Lessee and his surety to make payment of all royalties theretofore accrued and to place all wells on the surrendered land or in the surrendered zones or horizons in condition satisfactory to Lessor for suspension or abandonment; thereupon, Lessee shall be released from all other obligations accrued or to accrue under this lease with respect to the surrendered lands, zones, or horizons.

34. DEFAULT; TERMINATION. Whenever Lessee fails to comply with any of the provisions of this lease other than the payment of rental and Lessee fails within sixty days after written notice of such default to commence to remedy and thereafter prosecute diligently operations to remedy such default, Lessor may cancel this lease if at that time there is no well on said land capable of producing oil or gas in paying quantities. If at such time there is on said land a well capable of producing oil or gas in paying quantities, this lease may be cancelled only by judicial proceedings. In the event of any cancellation under this paragraph, Lessee shall have the right to retain under this lease any and all drilling or producing wells as to which no default exists together with a parcel of land surrounding each such well or wells and such rights of way through said land as may be reasonably necessary to enable Lessee to drill and operate such retained well or wells.

35. EXCESS AREA. If for any reason said land includes more acreage than the maximum permitted under applicable laws and/or regulations, this lease shall not be void but the acreage included in said land shall be reduced to the permitted maximum. Whenever Lessor determines that this lease so exceeds the permitted acreage and notifies Lessee stating the amount of acreage that must be eliminated, Lessee may within sixty days after such notice surrender one or more legal subdivisions included in said lands comprising at least the amount of acreage that must be eliminated. If such a surrender is not filed within such sixty days Lessor may terminate this lease as to the acreage that must be eliminated by mailing notice of such termination to Lessee describing the parcel or parcels eliminated. Such a notice shall have the effect of terminating this lease as to the parcel or parcels described in such notice.

36. RIGHTS ON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion of said lands, Lessee shall have the privilege at any time within a period of six months thereafter, or such extension thereof as may be granted by Lessor, of removing from said land or portion thereof all machinery, equipment, tools, and materials other than improvements needed for producing wells. Any materials, tools, appliances, machinery, structures, and equipment subject to removal as above provided which are allowed to remain on said land or portion thereof shall become the property of Lessor upon expiration of such period; provided, that Lessee shall remove any and all of such properties when so directed by Lessor. Subject to the foregoing, Lessee shall deliver up said lands or such portion or portions thereof in good order and condition.

37. INTEREST IN LAND. It is the intention of the parties that the rights vested in Lessee by this lease shall constitute an interest in real property in said land.

38. LESSOR INTEREST. If Lessor owns a lesser interest in the oil and gas deposits in said land than the entire and undivided fee simple estate, then the royalties and rentals herein provided shall be paid Lessor only in the proportion which its interest bears to the whole and undivided fee.

39. CONDITIONAL LEASE. If all or a part of said land is land that has been selected by the Lessor under laws of the United States granting lands to Lessor, but such land has not been patented to Lessor by the United States, then this lease is a conditional lease as provided by law until such patent become effective. If for any reason such a selection is not finally approved or such a patent does not become effective, and rental, royalty or minimum royalty payments made to Lessor under this lease will not be refunded.

40. DRILLING OPERATIONS. As used in this lease "drilling operations" mean any work or actual operations undertaken or commenced in good faith for the purpose of carrying out any of the rights, privileges or duties of Lessee under this lease, followed diligently and in due course by the construction of a road or derrick and/or other necessary structures for the drilling of an oil or gas well, and by the actual operation of drilling in the ground. Any such work or operations preliminary to drilling in the ground may be undertaken either on said land or in the vicinity of said land in any order Lessee shall see fit.

40. (a) ACTUAL DRILLING. As used in this lease, "actual drilling" means any and all operations necessary or convenient to the drilling of a well in the ground after the first drilling or spudding with equipment of sufficient size and capacity to drill to the total depth proposed for the well.

41. RULES AND REGULATIONS. As used in this lease "regulations" mean the applicable and valid oil and gas leasing regulations of the Commissioner of the Department of Natural Resources in effect on the effective date of this lease unless otherwise specified.

42. INTERPRETATION. As used in this lease words which are defined in the regulations have the meaning assigned by such definition except where the context clearly requires a different meaning. The paragraph headings are not a part of this lease and are inserted only for convenience.

43. NOTICES. Any notice required or permitted under this lease shall be in writing and shall be given by registered or certified mail, return receipt requested, addressed as follows:

To Lessor:
Director, Division of Lands
State of Alaska
344 Sixth Avenue
Anchorage, Alaska

To Lessee:
Pan American Petroleum Corporation
P. O. Box 712
Anchorage, Alaska

Any such notice shall be deemed given when delivered to the foregoing address. Either party may change the address to which such notices are to be sent, by a notice given in accordance with this paragraph.

44. HEIRS AND ASSIGNS. Subject to the other provisions of this lease, the covenants, conditions, and agreements contained in this lease shall extend to and be binding upon the heirs, executors, administrators, successors, or assigns of Lessor and Lessee.

45. WILDLIFE STIPULATIONS. This lease is subject to such stipulations as are attached.

IN WITNESS WHEREOF the parties have executed this lease.

Pan American Petroleum Corporation

By: Willard B. Congdon
Its Attorney in Fact

LESSEE

STATE OF ALASKA

By Roscoe E. Bell

Title Director, Div. of Lands LESSOR

THE UNITED STATES OF AMERICA }
STATE OF ALASKA } ss.

This certifies that on the 31 day of January, 19 62, before me, a notary public in and for the State of Alaska, duly commissioned and sworn, personally appeared ROSCOE E. BELL, to me known and known to me to be the person described in and who executed the foregoing lease on behalf of the State of Alaska as Director of the Division of Lands, Department of Natural Resources, or his authorized agent. The said ROSCOE E. BELL executed said lease in my presence and, after being duly sworn according to law, stated to me under oath that he is the Director of the Division of Lands, Department of Natural Resources, or his authorized agent, and has authority pursuant to law to execute the foregoing lease as such Director, or authorized agent, on behalf of the State of Alaska acting through the Division of Lands, Department of Natural Resources and that he executed the same freely and voluntarily as the free and voluntary act and deed of the said State of Alaska for the Division of Lands, Department of Natural Resources.

WITNESS my hand and official seal the day and year in this certificate above written.

Notary Public in and for Alaska. My Commission expires 9-27-65

AGO 801566

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APPLICABLE STATUTES

(s) *Short title.* This section may be cited as the Geothermal Resources Act.
(am §§ 40, 41 ch 127 SLA 1974)

Effect of amendment.
The 1974 amendment substituted "AS 41.08.020" for "AS 41.07.020" near the middle of subsection (b) (1) and "AS 41.08.040" for "AS 41.07.040" at the end of subsection (b) (2) and deleted "of 1971" from the end of subsection (s).

As the rest of the section was not affected by the amendment, it is not set out.

Legislative committee report.
For report on ch. 127, SLA 1974 (SCSHB 817 am S), see 1974 House Journal, p. 657.

Sec. 38.05.182. Royalty on natural resources. Any royalty provided for in §§ 135 — 181 of this chapter may be taken in kind rather than in money if the commissioner, with the consent of the Alaska Royalty Oil and Gas Development Advisory Board, determines that the taking in kind would be in the best interest of the state. The consent of the board is required only with respect to oil and gas royalty-in-kind under § 183 of this chapter. (§ 1 ch 56 SLA 1970; am § 7 ch 71 SLA 1971; am § 1 ch 9 SSSLA 1974; am § 5 ch 218 SLA 1976)

Effect of amendments. — The 1974 amendment substituted "if the commissioner, with the consent of the board, determines" for "at the discretion of the commissioner if he determines" near the middle of the first sentence and added the second sentence.

The 1976 amendment substituted "Alaska Royalty Oil and Gas Development Advisory Board" for "board" in the first sentence.

Sec. 38.05.183. Sale of royalty. (a) The sale, exchange or other disposal of a mineral obtained by the state as a royalty under § 182 of this chapter, or the sale, exchange or other disposal in whole or in part of a right to receive future mineral production under a state lease under this chapter, shall be by competitive bid and the sale, exchange or other disposal made to the highest responsible bidder, except that competitive bidding is not required when the commissioner, with the prior written approval of the Alaska Royalty Oil and Gas Development Advisory Board where applicable, determines that the best interest of the state does not require it or that no competition exists.

(b) When competitive bids are required, the commissioner, with the prior written approval of the Alaska Royalty Oil and Gas Development Advisory Board, may reject all bids if he determines that because of the amount of the bids, the lack of responsibility on the part of the bidders, or for reasons consistent with the criteria set out in AS 38.06.070, the acceptance of the bids would not be in the best interest of the state.

(c) If the commissioner determines that a sale, exchange or other disposal of a mineral obtained by the state as a royalty under § 182 of this chapter or of a right to receive future mineral production under a state lease under this chapter shall be made otherwise than by

competitive bid, and the Alaska Royalty Oil and Gas Development Advisory Board where applicable has approved that determination, the commissioner shall make public in writing the specific findings and conclusions upon which that determination is based.

(d) Oil or gas taken in kind by the state as its royalty share may not be sold or otherwise disposed of for export from the state until the commissioner with the approval of the Alaska Royalty Oil and Gas Development Advisory Board determines that the royalty-in-kind oil or gas is surplus to the present and projected intrastate domestic and industrial needs. The commissioner shall make public, in writing, the specific findings and reasons on which his determination is based and shall, within 10 days of the convening of a regular session of the legislature, submit a report showing the immediate and long-range domestic and industrial needs of the state for oil and gas and an analysis of how these needs are to be met. (§ 1 ch 56 SLA 1970; am § 3 ch 9 SSSLA 1974)

Effect of amendment. — The 1974 amendment rewrote this section.

Sec. 38.05.184. Limitation on oil and gas leases in certain areas, and reacquisition of leases. (a) The legislature finds that Kachemak Bay is an area of extraordinary abundance and diversity of marine life that has provided, and will continue to provide in the future, a basis for one of the state's most important commercial fisheries; that recent information discloses that even minute quantities of oil released into the marine environment may be harmful to the larval forms of crabs and other marine life and that the existence of gyral currents within the bay may increase the likelihood of oil coming into contact with these valuable commercial fish and shellfish species; and that therefore oil and gas development in the bay, at this time, presents an undue hazard to this valuable state renewable resource.

(b) No additional oil or gas leases may be issued by the Department of Natural Resources or any other state agency for the exploration for or the development or production of oil and gas on state-owned land and waters seaward of the mean higher high water line, beginning at Anchor Point; then around the perimeter of Kachemak Bay, to Point Pogibshi; then west to the three mile limit of state land and waters; then north to a point three miles west of Anchor Point; then east to the mean higher high water line of Anchor Point, the point of beginning.

(c) The commissioner of natural resources may enter into negotiations to reacquire by purchase in the name of the state, title to or accountable interests in oil or gas leases within the boundaries described in (b) of this section which were issued before June 4, 1976.

(d) In lieu of cash payment for a negotiated purchase of a leasehold interest, the commissioner may authorize a credit of the purchase price plus interest at the rate prescribed by AS 09.30.070 to be granted the

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public interest, or migration and spawning of fish in which there is a public interest.
(am § 4 ch 117 SLA 1976)

Effect of amendment. — The 1976 amendment added paragraphs (22) and (23).

As the rest of the section was not affected by the amendment, it is not set out.

Editor's note. — Section 1, ch. 117, SLA 1976, provides: "It is the intent of this Act to implement the provisions of art. VIII, sec. 14, Alaska State Constitution, relating to access to the navigable or public waters of the state."

Applied in Moore v. State, Sup. Ct. Op. No. 1284 (File Nos. 2551, 2587), 553 P.2d 8 (1976).

Chapter 06. Alaska Royalty Oil and Gas Development Advisory Board.

Section
10. Purpose
20. Establishment
25. Membership
30. Compensation; per diem, travel expenses
35. Meetings, rules, quorum, votes required; conflict of interest
40. Powers
50. Board approval required
55. Action by legislature
60. Confidentiality
70. Criteria
80. Definitions

Sec. 38.06.010. Purpose. It is the purpose of this chapter to facilitate the wise development of Alaska's oil and gas royalty interests by providing means and procedures for sales, exchanges or other disposition of those interests in ways calculated to promote private economic growth consistent with applicable environmental standards and public fiscal stability, and in accordance with AS 38.05.183. (§ 2 ch 9 SSSLA 1974)

Sec. 38.06.020. Establishment. There is established in the Department of Natural Resources the Alaska Royalty Oil and Gas Development Advisory Board. (§ 2 ch 9 SSSLA 1974)

Sec. 38.06.025. Membership. The board consists of the commissioner of natural resources, who is chairman, the commissioner of revenue, and three public members. Each of the public members shall possess experience in petroleum-related fields in such areas as exploration, development, production and economics, and shall be appointed by the governor to serve at his pleasure for three-year staggered terms and confirmed by a vote of a majority of the members of the legislature in joint sesssion. The public members may not be state officers or employees. A public member, upon the expiration of his term, shall continue to hold office until his successor is appointed and qualifies. Vacancies in public membership shall be filled in the same manner as original appointment. An appointee to fill a vacancy shall hold office for the balance of the term for which his predecessor on the board was appointed. A vacancy in board membership does not impair the authority of a quorum of the board members to exercise all the powers and duties of the board. (§ 2 ch 9 SSSLA 1974; am § 8 ch 207 SLA 1975)

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Effect of amendment. — The 1975 amendment, effective July 1, 1975, substituted "commissioner of revenue" for "commissioner of economic development" in the first sentence.

Sec. 38.06.030. Compensation; per diem, travel expenses. Members of the board are in the exempt service under AS 39.25.110 and shall receive per diem and travel allowances as provided by law for other boards and commissions. (§ 2 ch 9 SSSLA 1974)

Sec. 38.06.035. Meetings, rules, quorum, votes required; conflict of interest. (a) The board shall prescribe its own rules of procedure. It shall meet at a time and place determined by the chairman, and at other times and places as the chairman, or a majority of the board members, considers necessary. A quorum is a majority of the members of the board. The votes of the board members shall be recorded. Effective action to carry out the powers granted under this chapter requires the affirmative vote of a majority of the board members. No board member may, with respect to a matter before the board, vote for or on behalf of another member of the board.

(b) No member of the board may act upon a matter in which his relationship with any person creates a conflict of interest. No board member may have an official connection with or hold stock or securities in, or have a pecuniary interest in, a corporation, company or association engaged in the production or transportation of oil or gas. (§ 2 ch 9 SSSLA 1974)

Sec. 38.06.040. Powers. The board has the power to

(1) direct the commissioner of natural resources to solicit inquiries, development plans or bids from persons for the sale, exchange or other disposal of oil or gas or both obtained by the state as a royalty under AS 38.05.182, or for the sale, exchange or other disposal in whole or part of rights to receive future oil or gas production or both under a state lease, subject to terms and conditions established by the board;

(2) examine proposed sales, exchanges or other disposals of oil or gas or both obtained by the state as a royalty under AS 38.05.182, or of rights to receive future oil or gas production or both under a state lease, for the purpose of approving or disapproving the proposed sale, exchange or other disposal;

(3) hire an executive director, consultants expert in technical, economic or other relevant professions and other persons as necessary to assist the board in the exercise of its powers;

(4) promulgate regulations under the Administrative Procedure Act (AS 44.62) that are necessary or appropriate in the exercise of its powers; and

(5) take whatever other actions are reasonably necessary in the furtherance of the purposes of this chapter. (§ 2 ch 9 SSSLA 1974)

Sec. 38.06.050. Board approval required. (a) No sale, exchange, encumbrance, or other disposition of oil or gas or of the rights or waiver of the rights to receive future production of royalty oil or gas may be made by the commissioner of natural resources under AS 38.05.183 without the prior written approval of the board.

(b) Bids or applications for the purchase of royalty oil or gas may not be rejected by the commissioner of natural resources without the prior written approval of the board.

(c) Competitive bidding in a sale, exchange or other disposition described in (a) of this section may not be waived by the commissioner of natural resources under AS 38.05.183 without the prior written approval of the board.

(d) The board may require conditions relating to the sale, delivery, transportation, or refining or processing within the state to be included by the commissioner of natural resources in the offer of and sale by competitive bidding of oil or gas obtained by the state as royalty under AS 38.05.182. (§ 2 ch 9 SSSLA 1974)

Sec. 38.06.055. Action by legislature. (a) In addition to the approval by the board required under § 50 of this chapter, no sale, exchange or other disposition of oil or gas or of the rights or waiver of the rights to receive future production of royalty oil or gas may be made by the commissioner of natural resources under AS 38.05.183 without the prior approval of the legislature by a concurrent resolution concurred in by a majority of the members of each house.

(b) Until July 1, 1975, contracts for the sale of state-owned royalty gas or oil that specify the sale and delivery of not more than 400 barrels of crude oil per day or not more than 460 barrels of natural gas liquids per day or not more than 2,400 Mcf of natural gas per day may be executed without ratification by the legislature. (§ 2 ch 9 SSSLA 1974)

Sec. 38.06.060. Confidentiality. Notwithstanding AS 09.25.110 — 09.25.120, the board may provide by regulation for the confidentiality of those documents and records in its possession or control which contain confidential business or marketing information the protection of which is essential to the person who has submitted them to the board or in the judgment of the board is essential to the best interest of the state. Such confidentiality, however, shall not preclude the proper review by the legislature. (§ 2 ch 9 SSSLA 1974)

Sec. 38.06.070. Criteria. (a) In the exercise of its powers under § 40(1) — (2) and § 50 of this chapter the board shall consider

(1) the revenue needs and projected fiscal condition of the state;

(2) the existence and extent of present and projected local and regional needs for oil and gas products and by-products, the effect of state or federal commodity allocation requirements which might be applicable to those products and by-products, and the priorities among competing needs;

(3) the desirability of localized capital investment, increased payroll, secondary development and other possible effects of the sale, exchange or other disposition of oil and gas or both;

(4) the projected social impacts of the transaction;

(5) the projected additional costs and responsibilities which could be imposed upon the state and affected political subdivisions by development related to the transaction;

(6) the existence of specific local or regional labor or consumption markets or both which should be met by the transaction;

(7) the projected positive and negative environmental effects related to the transaction; and

(8) the projected effects of the proposed transaction upon existing private commercial enterprise and patterns of investments.

(b) When it is economically feasible, the board may require, as a condition of the sale of oil or gas obtained by the state as royalty, that the oil or gas be refined or processed in the state and may, when it is feasible and in the best interests of the state to do so, provide for processing or refining of the oil or gas under a contract entered into by competitive bidding before the sale of the oil or gas. (§ 2 ch 9 SSSLA 1974)

Sec. 38.06.080. Definitions. In this chapter

(1) "board" means the Alaska Royalty Oil and Gas Development Advisory Board; and

(2) "state lease" means an oil and gas lease on state land. (§ 2 ch 9 SSSLA 1974)

Chapter 35. Right-of-Way Leasing Act.

Section

10. Legislative declaration of policy
20. Grant of right-of-way lease
30. Abandonment, reduction or impairment of service of pipeline
40. Temporary or emergency service or temporary abandonment, reduction or impairment of service by lessee
50. Applications for right-of-way leases
60. [Repealed]
70. Notice of application
80. Analysis and public hearing
100. Decision on application
110. Term of lease
120. Covenants required to be included in lease
130. Right-of-way easements or leases acquired from others
140. Payment of rental and costs
150 — 160. [Repealed]
170. Forfeiture of lease
180. Suits to enjoin or recover damages for defaults
190. Application of the Administrative Procedure Act
200. Judicial review of decisions of commissioner on application
205. Lease savings clause
210. Delegation of commissioner's authority
220. Continued operation of certain carriers
225. Binding effect of covenants
230. Definitions

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(3) the desirability of localized capital investment, increased payroll, secondary development and other possible effects of the sale, exchange or other disposition of oil and gas or both;

(4) the projected social impacts of the transaction;

(5) the projected additional costs and responsibilities which could be imposed upon the state and affected political subdivisions by development related to the transaction;

(6) the existence of specific local or regional labor or consumption markets or both which should be met by the transaction;

(7) the projected positive and negative environmental effects related to the transaction; and

(8) the projected effects of the proposed transaction upon existing private commercial enterprise and patterns of investments.

(b) When it is economically feasible, the board may require, as a condition of the sale of oil or gas obtained by the state as royalty, that the oil or gas be refined or processed in the state and may, when it is feasible and in the best interests of the state to do so, provide for processing or refining of the oil or gas under a contract entered into by competitive bidding before the sale of the oil or gas. (§ 2 ch 9 SSSLA 1974)

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225. Binding effect of covenants
230. Definitions

Applied in Arco Pipeline Co. v. 3.60 Acres, More or Less, Sup. Ct. Op. No. 1177 (File No. 2419), 539 P.2d 64 (1975).

Sec. 38.35.010. Legislative declaration of policy. (a) The natural resources of this state in crude oil and natural gas and in its land for transportation of these resources and their products by pipeline toward markets both in and out of the state are capable of making a significant contribution to the general welfare of the people of this state. It is the policy of this state that the development, use, and control of a pipeline transportation system be directed to make the maximum contribution to the development of the human resources of this state, the increase in the standard of living for all of its residents, the advancement of existing and potential sectors of its economy, the strengthening of free competition in its private enterprise system, and the careful protection of its incomparable natural environment.

(b) The State of Alaska reserves unto itself all rights, powers, privileges and immunities not preempted by federal interstate commerce laws and regulations in the right-of-way leasing of any state lands for pipeline construction, transmission, or operation within its boundaries. (§ 1 ch 72 SLA 1972; am § 1 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment added subsection (b).

Sec. 38.35.020. Grant of right-of-way lease. (a) Rights-of-way on state land including rights-of-way over, under, along, across, or upon the right-of-way of a public road or highway or the right-of-way of a railroad or other public utility, or across, upon, over, or under a river or other body of water or land belonging to or administered by the state may be granted by noncompetitive lease by the commissioner for pipeline purposes for the transportation of oil, products or natural gas under those conditions prescribed by law or by administrative regulation. Except to the extent authorized by an oil and gas lease or unit agreement approved by the state, no person may engage in any construction or operation of any part of an oil, products, or natural gas pipeline, which in whole or in part is or is proposed to be on state land unless that person has obtained from the commissioner a right-of-way lease of the land under this chapter.

(b) The commissioner may by regulation exempt the construction or operation of field gathering lines or any reasonable classification of them from the requirement of a right-of-way lease under this chapter. (§ 1 ch 72 SLA 1972; am § 2 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment designated the provisions of this section as subsection (a), added the exception to the beginning of the second sentence of that subsection, made such other changes in that subsection as to make a detailed comparison impracticable, and added subsection (b).

Sec. 38.35.030. Abandonment, reduction or impairment of service of pipeline. No lessee may abandon any portion of a pipeline that is subject to a lease granted under this chapter, or operation or transportation, service, or sale by it, or reduce or impair service, except in accordance with the terms of the lease or § 40 of this chapter. (§ 1 ch 72 SLA 1972; am § 3 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment deleted "carrier" following "lessee" and substituted "subject to a lease granted under this chapter" for "on state public land or subject to the lease" and "except in accordance with the terms of the lease or § 40 of this chapter" for provisions requiring a certificate that the abandonment, reduction, or impairment is in accordance with the terms of the lease.

Sec. 38.35.040. Temporary or emergency service or temporary abandonment, reduction or impairment of service by lessee. The commissioner may, either upon a request made in the form he shall by regulation require, or upon his own motion without request, authorize or require temporary or emergency rendering of service or temporary or emergency abandonment, reduction or impairment of service by a pipeline of a lessee without compliance with §§ 50 — 100 of this chapter. Nothing in this section prevents a carrier from temporarily suspending operations in the event of an emergency which threatens public health or safety; however, notice shall be given the commissioner as soon as possible. (§ 1 ch 72 SLA 1972; am § 4 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment deleted "carrier" following "lessee" near the end of the first sentence.

Sec. 38.35.050. Applications for right-of-way leases. (a) A person or persons desiring to own a pipeline which is proposed to be located in whole or in part on state land, shall apply for a noncompetitive right-of-way lease of the state land.

(b) Applications under (a) of this section shall be made in a form and manner prescribed by regulation, and shall include any and all data, information, plans and exhibits which the commissioner determines are necessary to prepare the analysis required by § 80 of this chapter and to make a decision under § 100 of this chapter.

(c) Any amendment to an application filed under this section which constitutes a substantial change in the application is subject to all provisions of this chapter applying to an original application.

(d) All persons owning or planning to own an interest in a pipeline or proposed pipeline subject to a lease must join in the application under (a) of this section. Any person employed by the lessee in operating the

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pipeline is bound by the covenants of the lease applicable to functions within the scope of his employment as if he were an applicant under the lease and the state may enforce any breach of a covenant directly against an operator who is not in compliance with the covenant. (§ 1 ch 72 SLA 1972; am § 5 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.060. Application for certificate to abandon or diminish service.

Repealed by § 6 ch 3 FSSLA 1973.

Editor's note. — The repealed section derived from § 1, ch. 72, SLA 1972.

Sec. 38.35.070. Notice of application. Upon receiving an application under § 50 of this chapter, the commissioner shall

(1) cause notice of it to appear in a daily newspaper of general circulation published in the vicinity of the location of the proposed pipeline, the notice to include:

(A) a general description of the land involved;

(B) a summary of the substance of the application;

(2) file copies of the application with each coordinate agency;

(3) furnish at cost copies of a notice or application to persons requesting them; and

(4) provide other publication and notice he considers reasonable and appropriate to inform the public of the application. (§ 1 ch 72 SLA 1972; am § 7 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment deleted "or 60" following "§ 50" in the introductory language, substituted "a daily newspaper" for "the daily newspaper" and "in the vicinity of" for "nearest" in the introductory language of paragraph (1), inserted "the notice to include" in that language, added paragraphs (1)(A) and (1)(B), and added paragraph (4).

Sec. 38.35.080. Analysis and public hearing. (a) The commissioner shall, within a reasonable time after receiving the application, prepare an analysis of the application or of the matter of which he was notified, including a proposal for action if feasible; a proposed lease and a general statement of his basis and purpose, if favorable action is proposed; or, when a proposal for action is not feasible before a hearing, a description of the subjects and issues involved.

(b) Upon completion of the analysis but not less than 30 days before the date set for hearing an application or a substantial amendment to an application, the commissioner shall publish notice, and make copies available as provided in § 70 of this chapter.

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(c) The commissioner shall set all applications for public hearing as soon as practicable, if a public hearing on an application is requested by any person within 30 days of publication of notice under § 70(a) of this chapter or if the proposed action being considered involves a substantial public interest. The commissioner shall set the application for public hearing and publish notice of the time and place of the public hearing at least 30 days before the hearing.

(d) The provisions of the Administrative Procedure Act (AS 44.62) do not apply to hearings held under this section. (§ 1 ch 72 SLA 1972; am § 8 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment inserted "or of the matter of which he was notified" and deleted "or certificate or both" following "a proposed lease" in subsection (a), added the language beginning "if a public hearing on an application is requested" to the end of the first sentence of subsection (c), added the second sentence of that subsection, and added subsection (d).

Editor's note. — The reference to § 70(a) of this chapter in the first sentence of subsection (c) should be to § 70(1) of this chapter. AS 38.35.070 contains no subsection designations.

Sec. 38.35.100. Decision on application. (a) The commissioner shall promptly determine, on an application filed with him under § 50 of this chapter, whether the applicant is fit, willing and able to perform the transportation or other acts proposed in a manner that will be required by the present or future public interest. In making a determination the commissioner shall consider whether or not

(1) the proposed use of the right-of-way will unreasonably conflict with existing uses of the land involving a superior public interest;

(2) the applicant has the technical and financial capability to protect state and private property interests;

(3) the applicant has the technical and financial capability to take action to the extent reasonably practical to

(A) prevent any significant adverse environmental impact, including but not limited to, erosion of the surface of the land and damage to fish and wildlife and their habitat;

(B) undertake any necessary restoration or revegetation; and

(C) protect the interests of individuals living in the general area of the right-of-way who rely on fish, wildlife and biotic resources of the area for subsistence purposes;

(4) the applicant has the financial capability to pay reasonably foreseeable damages for which he may become liable on claims arising from the construction, operation, maintenance or termination of the pipeline.

(b) If the commissioner makes these determinations favorably to the applicant, then he may grant the whole or part of the application. Otherwise, he shall deny the application. In order to grant the whole or part of the application the commissioner shall offer a lease to the applicant for its acceptance through signing of the lease and agreeing

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to comply with its terms, conditions, and obligations. Only upon proper acceptance of offered lease by the applicant within 30 days after its having been presented is the grant of the application consummated. (§ 1 ch 72 SLA 1972; am § 9 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.110. Term of lease. Each lease of state land for pipeline right-of-way purposes shall contain a provision that the lease shall run for a specified term of not greater than 30 years, and shall be renewable for additional periods of up to 10 years each, so long as the lessee is in commercial operation and is in full compliance with all state law, including but not limited to state law pertaining to regulation and taxation of the pipeline facility, and is in compliance with all terms of the lease. In making this determination he shall take into consideration the cost of the proposed pipeline, its useful life, and the probable financing requirement for the proposed pipeline. (§ 1 ch 72 SLA 1972; am § 10 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment substituted "30 years" for "25 years" and inserted "is in commercial operation and" in the first sentence and added the second sentence.

Sec. 38.35.120. Covenants required to be included in lease. (a) A noncompetitive lease of state land for a right-of-way for an oil or natural gas pipeline valued at $1,000,000 or more may be granted only upon the condition that the lessee expressly covenants in the lease, in consideration of the rights acquired by it under the lease, that

(1) it assumes the status of and will perform all of its functions undertaken under the lease as a common carrier and will accept, convey, and transport without discrimination crude oil or natural gas, depending on the kind of pipeline involved, delivered to it for transportation from fields in the vicinity of the pipeline subject to the lease throughout its route both on state land obtained under the lease and on other land; however, a lessee who owns or operates a natural gas pipeline subject to regulation either (A) under the Natural Gas Act (15 U.S.C. 717 et seq.) of the United States, or (B) by the state or political subdivisions with respect to rates and charges for the sale of natural gas, is, to the extent of that regulation, exempt from the common carrier requirement in this paragraph; it will accept, convey, and transport crude oil or natural gas without unjust or unreasonable discrimination in favor of one producer or person, including itself, as against another but will take the crude oil or natural gas, depending on the kind of pipeline involved, delivered or offered, without unreasonable discrimination, that the Alaska Pipeline Commission shall, after a full hearing with due notice to the interested parties and a proper finding of facts, determine to be reasonable in the performance of its duties as a common carrier;

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(2) it will interchange crude oil or natural gas, depending on the kind of pipeline involved, with each like common carrier and provide connections and facilities for the interchange of crude oil or natural gas at every locality reached by both pipelines when the necessity exists, subject to rates and regulations made by the appropriate state or federal regulatory agency;

(3) it will maintain and preserve books, accounts, and records and will make those reports that the state may prescribe by regulation or law as necessary and appropriate for purposes of administration of this chapter;

(4) it will accord at all reasonable times to the state and its authorized agents and auditors the right of access to its property and records, of inspection of its property, and of examination and copying of records;

(5) it will provide connections, as determined by the Alaska Pipeline Commission under AS 42.06.340, to facilities on the pipeline subject to the lease, both on state land and other land in the state, for the purpose of delivering crude oil or natural gas, depending on the kind of pipeline involved, to persons (including the state and its political subdivisions) contracting for the purchase at wholesale of crude oil or natural gas transported by the pipeline when required by the public interest;

(6) it shall, notwithstanding any other provision, provide connections and interchange facilities at state expense at such places the state considers necessary if the state determines to take a portion of its royalty or taxes in oil or natural gas;

(7) it will construct and operate the pipeline in accordance with applicable state laws and lawful regulations and orders of the Alaska Pipeline Commission;

(8) it will, at its own expense, during the term of the lease

(A) maintain the leasehold and pipeline in good repair;

(B) promptly repair or remedy any damage to the leasehold;

(C) promptly compensate for any damage to or destruction of property for which the lessee is liable resulting from damage to or destruction of the leasehold or pipeline;

(9) it will not transfer, assign, or dispose of in any manner, directly or indirectly, or by transfer of control of the carrier corporation, its interest in a right-of-way lease, or any rights under the lease or any pipeline subject to the lease to any person other than another owner of the pipeline (including subsidiaries, parents and affiliates of the owners), except to the extent that the commissioner, after consideration of the protection of the public interest (including whether the proposed transferee is fit, willing and able to perform the transportation or other acts proposed in a manner that will reasonably protect the lives, property and general welfare of the people of Alaska), authorizes; the commissioner shall not unreasonably withhold his consent to the transfer, assignment or disposal;

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(10) it will file with the commissioner a written appointment of a named permanent resident of the state to be its registered agent in the state and to receive service of notices, regulations, decisions and orders of the commissioner; if it fails to appoint an agent for service, service may be made by posting a copy in the office of the commissioner and filing a copy of it in the office of the lieutenant governor and by mailing a copy to the lessee's last known address;

(11) the applicable law of this state will be used in resolving questions of interpretation of the lease;

(12) the granting of the right-of-way lease is subject to the express condition that the exercise of the rights and privileges granted under the lease will not unduly interfere with the management, administration, or disposal by the state of the land affected by the lease, and that the lessee agrees and consents to the occupancy and use by the state, its grantees, permittees, or other lessees of any part of the right-of-way not actually occupied or required by the pipeline for the full and safe utilization of the pipeline, for necessary operations incident to land management, administration, or disposal;

(13) it will be liable to the state for damages or injury incurred by the state caused by the construction, operation or maintenance of the pipeline and it will indemnify the state for the liabilities or damages;

(14) it will procure and furnish liability and property damage insurance from a company licensed to do business in the state or furnish other security or undertaking upon the terms and conditions the commissioner considers necessary if the commissioner finds that the net assets of the lessee are insufficient to protect the public from damage for which the lessee may be liable arising out of the construction or operation of the pipeline.

(b) For a right-of-way lease granted under this chapter for an oil or natural gas pipeline valued at $1,000,000 or more to be valid and of legal effect, it must contain the terms required to be inserted under the provisions of §§ 110 — 140 of this chapter. An oil or natural gas pipeline right-of-way lease granted under this chapter that does not contain the required terms is null and void and without legal effect and does not vest any interest in state land or any authority in the carrier granted the lease.

(c) The commissioner may insert in any right-of-way lease other reasonable provisions and conditions that he determines the public interest requires.

(d) The lease will also contain terms and conditions that are reasonably necessary to obligate the lessee, to the extent reasonably practicable, to

(1) prevent conflicts with other existing uses of the land involving a superior public interest;

(2) protect state and private property interests;

(3) prevent any significant adverse environmental impact, including but not limited to the erosion of the surface of the land, and damage to fish and wildlife and their habitat;

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(4) restore and revegetate during the term and at termination of the lease; and

(5) protect the interests of individuals living in the general area of the right-of-way who rely on the fish, wildlife, and biotic resources of the area for subsistence purposes.

(e) In the event the commissioner proposes to offer a lease or leases to two or more lessees for the same pipeline, the commissioner may include terms in the lease or leases which establish the limit of the obligations and liabilities of each lessee arising under this chapter or under the lease or leases.

(f) The commissioner may, at his discretion, include any or all of the terms set out in this section in leases of state land for products pipeline right-of-way purposes. (§ 1 ch 72 SLA 1972; am § 11 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.130. Right-of-way easements or leases acquired from others. (a) The lessee may, if the commissioner delegates the function to it, condemn, by declaration of taking, under AS 09.55.420 — 09.55.450, real property and acquire leases of or easements or rights-of-way on lands in the state required for right-of-way purposes for a pipeline subject to the lease on behalf of and as agent for the state in which title to or interest in the land shall vest.

(b) The lease shall contain a covenant that the land, right-of-way, or easement acquired under this section is or will form part of the land leased to the lessee. (§ 1 ch 72 SLA 1972; am § 12 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote subsection (a), deleting the paragraph designations and deleting the provisions of former paragraphs (1) and (2). The amendment also, in subsection (b), substituted "The lease shall contain a covenant" for "The lease covenant required by this section shall be accompanied by a provision" and deleted "carrier" following "lessee."

Quoted in Arco Pipeline Co. v. 3.60 Acres, More or Less, Sup. Ct. Op. No. 1177 (File No. 2419), 539 P.2d 64 (1975).

Sec. 38.35.140. Payment of rental and costs. (a) The lease price for a right-of-way lease shall be the annual fair market rental of the state lands included in the right-of-way based on the appraised fair market value of the land. The lease price is payable annually in advance on or before the anniversary of the lease. The appraised fair market rental value shall be adjusted periodically under the provisions of AS 38.05.015. Rental may not be charged for any land acquired by the lessee under § 130(b) of this chapter and conveyed without cost to the state.

(b) The lessee shall reimburse the state for all reasonable costs incurred in monitoring the construction of the pipeline on the right-of-way. (§ 1 ch 72 SLA 1972; am § 13 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.150. Additional provisions of lease.

Repealed by § 14 ch 3 FSSLA 1973.

Editor's note. — The repealed section derived from § 1, ch. 72, SLA 1972.

Sec. 38.35.160. Transfer of right-of-way lease, certificates, or pipeline.

Repealed by § 15 ch 3 FSSLA 1973.

Editor's note. — The repealed section derived from § 1, ch. 72, SLA 1972.

Sec. 38.35.170. Forfeiture of lease. Failure to begin construction of the pipeline facility within a reasonable time of the granting of a right-of-way lease under this chapter for reasons within the control of the lessee or failure of an owner of an interest in the granted right-of-way substantially to comply with the terms of the right-of-way shall be grounds for forfeiture of the right-of-way interest of the lessee or owner in an action brought by the commissioner in the superior court. Before the commencement of any action for forfeiture of an interest in a right-of-way under this section, the commissioner shall give the lessee or owner of the interest notice in writing of the alleged default and shall not commence the proceeding unless the lessee or owner of the interest has failed to initiate good faith efforts to cure the default within 60 days of the notice of the alleged default. (§ 1 ch 72 SLA 1972; am § 16 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.180. Suits to enjoin or recover damages for defaults.

(c) Neither this section nor the state's obtaining an injunction or recovering penalties extinguishes any civil cause of action arising out of a violation of this chapter or the provisions of a right-of-way lease. (am § 17 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment, in subsection (c), deleted "or criminal responsibility" following "civil cause of action" and "or certificate under a lease" following "a right-of-way lease," inserted "or the provisions of," and deleted the former second sentence.

As the rest of the section was not affected by the amendment, it is not set out.

Sec. 38.35.190. Application of the Administrative Procedure Act.

(a) AS 44.62.010 — 44.62.320, 44.62.640 and 44.62.650 apply to

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regulations adopted by the commissioner under the authority of this chapter.

(b) Repealed by § 18 ch 3 FSSLA 1973.

(c) Repealed by § 18 ch 3 FSSLA 1973.

(d) Repealed by § 18 ch 3 FSSLA 1973. (§ 1 ch 72 SLA 1972; am § 18 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment repealed subsections (b), (c), and (d).

Sec. 38.35.200. Judicial review of decisions of commissioner on application. (a) An applicant or competing applicant or a person who has a direct financial interest affected by the lease who raises objections within 60 days of the publication of notice under § 70 of this chapter are the only persons with standing to seek judicial review of a decision of the commissioner under § 100 of this chapter.

(b) The only grounds for judicial review of a decision of the commissioner are

(1) failure to follow the procedures set out in this chapter; or

(2) abuse of discretion so capricious, arbitrary or confiscatory as to constitute a denial of due process. (§ 1 ch 72 SLA 1972; am § 19 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.205. Lease savings clause. A judicial finding that any term or condition of a right-of-way lease issued under this chapter is unlawful or invalid may not operate to invalidate the lease or any other term or condition of the lease. (§ 23 ch 3 FSSLA 1973)

Sec. 38.35.210. Delegation of commissioner's authority. The commissioner may delegate to an employee of the Department of Natural Resources or the Department of Law the authority granted under this chapter, except for the authority to execute leases. (§ 1 ch 72 SLA 1972; am § 20 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment deleted "and certificates" following "leases" at the end of the section.

Sec. 38.35.220. Continued operation of certain carriers.

(d) Repealed by § 21 ch 3 FSSLA 1973.
(am § 21 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment repealed subsection (d).

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Sec. 38.35.225. Binding effect of covenants. By entering into a lease under this chapter, the lessee is bound by all the covenants provided for in the lease to the full extent of the power of the state to impose those covenants under its authority as owner of the land to be leased or under its police or regulatory powers or otherwise; provided that the right of the lessee to challenge the power of the state to require such a covenant as owner of the land to be leased or under its police or regulatory powers or otherwise is preserved until such time as action to enforce the covenant is taken by the state. (§ 23 ch 3 FSSLA 1973)

Sec. 38.35.230. Definitions. In this chapter

(1) "commissioner" means the commissioner of natural resources;

(2) "coordinate agencies" includes Department of Labor, Department of Highways, Department of Environmental Conservation, and the Alaska Pipeline Commission;

(3) "lease" means the instrument or extension of an instrument issued under this chapter granting a leasehold interest in state land for pipeline right-of-way purposes to a person and authorizing the construction or operation of, or transportation, service or sale by a pipeline for crude oil, natural gas, or products;

(4) "lessee" means a person or persons holding a valid lease issued by the commissioner;

(5) "natural gas" includes all hydrocarbons produced at the wellhead not defined as oil;

(6) "oil" includes crude petroleum oil and other hydrocarbons regardless of gravity which are produced at the wellhead in liquid form and the liquid hydrocarbons known as distillate or condensate recovered or extracted from gas, other than gas produced in association with oil and commonly known as casinghead gas;

(7) "pipeline" or "pipeline facility" means all the facilities of a total system of pipe (whether owned or operated under a contract, agreement, or lease) used by a carrier for transportation of crude oil, natural gas, or products for delivery, for storage, or for further transportation, and including all pipe, pump or compressor stations, station equipment, tanks, valves, access roads, bridges, airfields, terminals and terminal facilities, including docks and tanker loading facilities, operations control center for both the upstream part of the pipeline and the terminal, tanker ballast treatment facilities, and fire protection system, communication system, and all other facilities used or necessary for an integral line of pipe, taken as a whole, to effectuate transportation, including an extension or enlargement of the line;

(8) "product" means refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, gas oil, casinghead gasoline, natural gas gasoline, naphtha, distillate, gasoline, kerosene, benzine, wash oil, waste oil, blended gasoline, lubricating oil, blends or mixtures of petroleum and any liquid product or by-product derived from crude petroleum oil or natural gas;

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(9) "state land" means

(A) "state lands" as defined in AS 38.05.365;

(B) public land of the United States selected by the state under sec. 6 of the Alaska Statehood Act of 1958 (PL 85-508; 72 Stat. 399), as amended, and real property of the United States transferred to the state under secs. 21, 35 and 45 of the Alaska Omnibus Act of 1959 (PL 86-70; 73 Stat. 141), as amended;

(C) any interest owned by the state in land;

(10) "transportation" means the shipment or carriage by a pipeline of crude oil, natural gas, or products from an upstream terminus in one or more fields or points of production or supply of the minerals to a downstream terminus in one or more points for delivery of the minerals to a purchaser or consignee, for storage, or for further carriage or shipment, including shipment or carriage within the state that may be classified as interstate or foreign transportation to the extent that the transportation may constitutionally be subjected to the provisions of this chapter, as well as all services necessary to effectuate shipment or carriage, including, among other things, the receipt, storage, processing, handling, transfer in transit, forwarding, and delivery of the minerals. (§ 1 ch 72 SLA 1972; am § 22 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Chapter 40. Local Hire Under State Leases.

Section	Section
30. Resident employment	70. Penalties
40. Reporting provisions	80. Injunctive relief
60. Hearings and investigations	90. Definitions

Sec. 38.40.030. Resident employment. (a) In order to create, protect and preserve the right of Alaska residents to employment, the commissioner of natural resources shall incorporate into all oil and gas leases, easements or right-of-way permits for oil or gas pipeline purposes, unitization agreements, or any renegotiation of any of the preceding to which the state is a party, provisions requiring the lessee to comply with applicable laws and regulations with regard to the employment of Alaska residents, a provision requiring the employment of qualified Alaska residents, a provision prohibiting discrimination against Alaska residents and, when in the determination of the commissioner of natural resources it is practicable, a provision requiring compliance with the Alaska Plan, all in accordance with the provisions of this chapter.

(b) All employment falling within the purview of § 50 of this chapter shall be filled by Alaska residents if they are qualified and available. The commissioner of labor, whose decision is final as to residency, shall determine the resident status of individuals for purposes of this chapter

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(3) the desirability of localized capital investment, increased payroll, secondary development and other possible effects of the sale, exchange or other disposition of oil and gas or both;

(4) the projected social impacts of the transaction;

(5) the projected additional costs and responsibilities which could be imposed upon the state and affected political subdivisions by development related to the transaction;

(6) the existence of specific local or regional labor or consumption markets or both which should be met by the transaction;

(7) the projected positive and negative environmental effects related to the transaction; and

(8) the projected effects of the proposed transaction upon existing private commercial enterprise and patterns of investments.

(b) When it is economically feasible, the board may require, as a condition of the sale of oil or gas obtained by the state as royalty, that the oil or gas be refined or processed in the state and may, when it is feasible and in the best interests of the state to do so, provide for processing or refining of the oil or gas under a contract entered into by competitive bidding before the sale of the oil or gas. (§ 2 ch 9 SSSLA 1974)

Sec. 38.06.080. Definitions. In this chapter

(1) "board" means the Alaska Royalty Oil and Gas Development Advisory Board; and

(2) "state lease" means an oil and gas lease on state land. (§ 2 ch 9 SSSLA 1974)

Chapter 35. Right-of-Way Leasing Act.

Section		Section	
10.	Legislative declaration of policy	140.	Payment of rental and costs
20.	Grant of right-of-way lease	150 — 160.	[Repealed]
30.	Abandonment, reduction or impairment of service of pipeline	170.	Forfeiture of lease
40.	Temporary or emergency service or temporary abandonment, reduction or impairment of service by lessee	180.	Suits to enjoin or recover damages for defaults
50.	Applications for right-of-way leases	190.	Application of the Administrative Procedure Act
60.	[Repealed]	200.	Judicial review of decisions of commissioner on application
70.	Notice of application	205.	Lease savings clause
80.	Analysis and public hearing	210.	Delegation of commissioner's authority
100.	Decision on application	220.	Continued operation of certain carriers
110.	Term of lease	225.	Binding effect of covenants
120.	Covenants required to be included in lease	230.	Definitions
130.	Right-of-way easements or leases acquired from others		

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Applied in Arco Pipeline Co. v. 3.60 Acres, More or Less, Sup. Ct. Op. No. 1177 (File No. 2419), 539 P.2d 64 (1975).

Sec. 38.35.010. Legislative declaration of policy. (a) The natural resources of this state in crude oil and natural gas and in its land for transportation of these resources and their products by pipeline toward markets both in and out of the state are capable of making a significant contribution to the general welfare of the people of this state. It is the policy of this state that the development, use, and control of a pipeline transportation system be directed to make the maximum contribution to the development of the human resources of this state, the increase in the standard of living for all of its residents, the advancement of existing and potential sectors of its economy, the strengthening of free competition in its private enterprise system, and the careful protection of its incomparable natural environment.

(b) The State of Alaska reserves unto itself all rights, powers, privileges and immunities not preempted by federal interstate commerce laws and regulations in the right-of-way leasing of any state lands for pipeline construction, transmission, or operation within its boundaries. (§ 1 ch 72 SLA 1972; am § 1 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment added subsection (b).

Sec. 38.35.020. Grant of right-of-way lease. (a) Rights-of-way on state land including rights-of-way over, under, along, across, or upon the right-of-way of a public road or highway or the right-of-way of a railroad or other public utility, or across, upon, over, or under a river or other body of water or land belonging to or administered by the state may be granted by noncompetitive lease by the commissioner for pipeline purposes for the transportation of oil, products or natural gas under those conditions prescribed by law or by administrative regulation. Except to the extent authorized by an oil and gas lease or unit agreement approved by the state, no person may engage in any construction or operation of any part of an oil, products, or natural gas pipeline, which in whole or in part is or is proposed to be on state land unless that person has obtained from the commissioner a right-of-way lease of the land under this chapter.

(b) The commissioner may by regulation exempt the construction or operation of field gathering lines or any reasonable classification of them from the requirement of a right-of-way lease under this chapter. (§ 1 ch 72 SLA 1972; am § 2 ch 3 FSSLA 1973)

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Effect of amendment. — The 1973 amendment designated the provisions of this section as subsection (a), added the exception to the beginning of the second sentence of that subsection, made such other changes in that subsection as to make a detailed comparison impracticable, and added subsection (b).

Sec. 38.35.030. Abandonment, reduction or impairment of service of pipeline. No lessee may abandon any portion of a pipeline that is subject to a lease granted under this chapter, or operation or transportation, service, or sale by it, or reduce or impair service, except in accordance with the terms of the lease or § 40 of this chapter. (§ 1 ch 72 SLA 1972; am § 3 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment deleted "carrier" following "lessee" and substituted "subject to a lease granted under this chapter" for "on state public land or subject to the lease" and "except in accordance with the terms of the lease or § 40 of this chapter" for provisions requiring a certificate that the abandonment, reduction, or impairment is in accordance with the terms of the lease.

Sec. 38.35.040. Temporary or emergency service or temporary abandonment, reduction or impairment of service by lessee. The commissioner may, either upon a request made in the form he shall by regulation require, or upon his own motion without request, authorize or require temporary or emergency rendering of service or temporary or emergency abandonment, reduction or impairment of service by a pipeline of a lessee without compliance with §§ 50 — 100 of this chapter. Nothing in this section prevents a carrier from temporarily suspending operations in the event of an emergency which threatens public health or safety; however, notice shall be given the commissioner as soon as possible. (§ 1 ch 72 SLA 1972; am § 4 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment deleted "carrier" following "lessee" near the end of the first sentence.

Sec. 38.35.050. Applications for right-of-way leases. (a) A person or persons desiring to own a pipeline which is proposed to be located in whole or in part on state land, shall apply for a noncompetitive right-of-way lease of the state land.

(b) Applications under (a) of this section shall be made in a form and manner prescribed by regulation, and shall include any and all data, information, plans and exhibits which the commissioner determines are necessary to prepare the analysis required by § 80 of this chapter and to make a decision under § 100 of this chapter.

(c) Any amendment to an application filed under this section which constitutes a substantial change in the application is subject to all provisions of this chapter applying to an original application.

(d) All persons owning or planning to own an interest in a pipeline or proposed pipeline subject to a lease must join in the application under (a) of this section. Any person employed by the lessee in operating the

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pipeline is bound by the covenants of the lease applicable to functions within the scope of his employment as if he were an applicant under the lease and the state may enforce any breach of a covenant directly against an operator who is not in compliance with the covenant. (§ 1 ch 72 SLA 1972; am § 5 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.060. Application for certificate to abandon or diminish service.

Repealed by § 6 ch 3 FSSLA 1973.

Editor's note. — The repealed section derived from § 1, ch. 72, SLA 1972.

Sec. 38.35.070. Notice of application. Upon receiving an application under § 50 of this chapter, the commissioner shall

(1) cause notice of it to appear in a daily newspaper of general circulation published in the vicinity of the location of the proposed pipeline, the notice to include:

(A) a general description of the land involved;

(B) a summary of the substance of the application;

(2) file copies of the application with each coordinate agency;

(3) furnish at cost copies of a notice or application to persons requesting them; and

(4) provide other publication and notice he considers reasonable and appropriate to inform the public of the application. (§ 1 ch 72 SLA 1972; am § 7 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment deleted "or 60" following "§ 50" in the introductory language, substituted "a daily newspaper" for "the daily newspaper" and "in the vicinity of" for "nearest" in the introductory language of paragraph (1), inserted "the notice to include" in that language, added paragraphs (1)(A) and (1)(B), and added paragraph (4).

Sec. 38.35.080. Analysis and public hearing. (a) The commissioner shall, within a reasonable time after receiving the application, prepare an analysis of the application or of the matter of which he was notified, including a proposal for action if feasible; a proposed lease and a general statement of his basis and purpose, if favorable action is proposed; or, when a proposal for action is not feasible before a hearing, a description of the subjects and issues involved.

(b) Upon completion of the analysis but not less than 30 days before the date set for hearing an application or a substantial amendment to an application, the commissioner shall publish notice, and make copies available as provided in § 70 of this chapter.

(c) The commissioner shall set all applications for public hearing as soon as practicable, if a public hearing on an application is requested by any person within 30 days of publication of notice under § 70(a) of this chapter or if the proposed action being considered involves a substantial public interest. The commissioner shall set the application for public hearing and publish notice of the time and place of the public hearing at least 30 days before the hearing.

(d) The provisions of the Administrative Procedure Act (AS 44.62) do not apply to hearings held under this section. (§ 1 ch 72 SLA 1972; am § 8 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment inserted "or of the matter of which he was notified" and deleted "or certificate or both" following "a proposed lease" in subsection (a), added the language beginning "if a public hearing on an application is requested" to the end of the first sentence of subsection (c), added the second sentence of that subsection, and added subsection (d).

Editor's note. — The reference to § 70(a) of this chapter in the first sentence of subsection (c) should be to § 70(1) of this chapter. AS 38.35.070 contains no subsection designations.

Sec. 38.35.100. Decision on application. (a) The commissioner shall promptly determine, on an application filed with him under § 50 of this chapter, whether the applicant is fit, willing and able to perform the transportation or other acts proposed in a manner that will be required by the present or future public interest. In making a determination the commissioner shall consider whether or not

(1) the proposed use of the right-of-way will unreasonably conflict with existing uses of the land involving a superior public interest;

(2) the applicant has the technical and financial capability to protect state and private property interests;

(3) the applicant has the technical and financial capability to take action to the extent reasonably practical to

(A) prevent any significant adverse environmental impact, including but not limited to, erosion of the surface of the land and damage to fish and wildlife and their habitat;

(B) undertake any necessary restoration or revegetation; and

(C) protect the interests of individuals living in the general area of the right-of-way who rely on fish, wildlife and biotic resources of the area for subsistence purposes;

(4) the applicant has the financial capability to pay reasonably foreseeable damages for which he may become liable on claims arising from the construction, operation, maintenance or termination of the pipeline.

(b) If the commissioner makes these determinations favorably to the applicant, then he may grant the whole or part of the application. Otherwise, he shall deny the application. In order to grant the whole or part of the application the commissioner shall offer a lease to the applicant for its acceptance through signing of the lease and agreeing

to comply with its terms, conditions, and obligations. Only upon proper acceptance of offered lease by the applicant within 30 days after its having been presented is the grant of the application consummated. (§ 1 ch 72 SLA 1972; am § 9 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.110. Term of lease. Each lease of state land for pipeline right-of-way purposes shall contain a provision that the lease shall run for a specified term of not greater than 30 years, and shall be renewable for additional periods of up to 10 years each, so long as the lessee is in commercial operation and is in full compliance with all state law, including but not limited to state law pertaining to regulation and taxation of the pipeline facility, and is in compliance with all terms of the lease. In making this determination he shall take into consideration the cost of the proposed pipeline, its useful life, and the probable financing requirement for the proposed pipeline. (§ 1 ch 72 SLA 1972; am § 10 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment substituted "30 years" for "25 years" and inserted "is in commercial operation and" in the first sentence and added the second sentence.

Sec. 38.35.120. Covenants required to be included in lease. (a) A noncompetitive lease of state land for a right-of-way for an oil or natural gas pipeline valued at $1,000,000 or more may be granted only upon the condition that the lessee expressly covenants in the lease, in consideration of the rights acquired by it under the lease, that

(1) it assumes the status of and will perform all of its functions undertaken under the lease as a common carrier and will accept, convey, and transport without discrimination crude oil or natural gas, depending on the kind of pipeline involved, delivered to it for transportation from fields in the vicinity of the pipeline subject to the lease throughout its route both on state land obtained under the lease and on other land; however, a lessee who owns or operates a natural gas pipeline subject to regulation either (A) under the Natural Gas Act (15 U.S.C. 717 et seq.) of the United States, or (B) by the state or political subdivisions with respect to rates and charges for the sale of natural gas, is, to the extent of that regulation, exempt from the common carrier requirement in this paragraph; it will accept, convey, and transport crude oil or natural gas without unjust or unreasonable discrimination in favor of one producer or person, including itself, as against another but will take the crude oil or natural gas, depending on the kind of pipeline involved, delivered or offered, without unreasonable discrimination, that the Alaska Pipeline Commission shall, after a full hearing with due notice to the interested parties and a proper finding of facts, determine to be reasonable in the performance of its duties as a common carrier;

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(2) it will interchange crude oil or natural gas, depending on the kind of pipeline involved, with each like common carrier and provide connections and facilities for the interchange of crude oil or natural gas at every locality reached by both pipelines when the necessity exists, subject to rates and regulations made by the appropriate state or federal regulatory agency;

(3) it will maintain and preserve books, accounts, and records and will make those reports that the state may prescribe by regulation or law as necessary and appropriate for purposes of administration of this chapter;

(4) it will accord at all reasonable times to the state and its authorized agents and auditors the right of access to its property and records, of inspection of its property, and of examination and copying of records;

(5) it will provide connections, as determined by the Alaska Pipeline Commission under AS 42.06.340, to facilities on the pipeline subject to the lease, both on state land and other land in the state, for the purpose of delivering crude oil or natural gas, depending on the kind of pipeline involved, to persons (including the state and its political subdivisions) contracting for the purchase at wholesale of crude oil or natural gas transported by the pipeline when required by the public interest;

(6) it shall, notwithstanding any other provision, provide connections and interchange facilities at state expense at such places the state considers necessary if the state determines to take a portion of its royalty or taxes in oil or natural gas;

(7) it will construct and operate the pipeline in accordance with applicable state laws and lawful regulations and orders of the Alaska Pipeline Commission;

(8) it will, at its own expense, during the term of the lease

(A) maintain the leasehold and pipeline in good repair;

(B) promptly repair or remedy any damage to the leasehold;

(C) promptly compensate for any damage to or destruction of property for which the lessee is liable resulting from damage to or destruction of the leasehold or pipeline;

(9) it will not transfer, assign, or dispose of in any manner, directly or indirectly, or by transfer of control of the carrier corporation, its interest in a right-of-way lease, or any rights under the lease or any pipeline subject to the lease to any person other than another owner of the pipeline (including subsidiaries, parents and affiliates of the owners), except to the extent that the commissioner, after consideration of the protection of the public interest (including whether the proposed transferee is fit, willing and able to perform the transportation or other acts proposed in a manner that will reasonably protect the lives, property and general welfare of the people of Alaska), authorizes; the commissioner shall not unreasonably withhold his consent to the transfer, assignment or disposal;

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(10) it will file with the commissioner a written appointment of a named permanent resident of the state to be its registered agent in the state and to receive service of notices, regulations, decisions and orders of the commissioner; if it fails to appoint an agent for service, service may be made by posting a copy in the office of the commissioner and filing a copy of it in the office of the lieutenant governor and by mailing a copy to the lessee's last known address;

(11) the applicable law of this state will be used in resolving questions of interpretation of the lease;

(12) the granting of the right-of-way lease is subject to the express condition that the exercise of the rights and privileges granted under the lease will not unduly interfere with the management, administration, or disposal by the state of the land affected by the lease, and that the lessee agrees and consents to the occupancy and use by the state, its grantees, permittees, or other lessees of any part of the right-of-way not actually occupied or required by the pipeline for the full and safe utilization of the pipeline, for necessary operations incident to land management, administration, or disposal;

(13) it will be liable to the state for damages or injury incurred by the state caused by the construction, operation or maintenance of the pipeline and it will indemnify the state for the liabilities or damages;

(14) it will procure and furnish liability and property damage insurance from a company licensed to do business in the state or furnish other security or undertaking upon the terms and conditions the commissioner considers necessary if the commissioner finds that the net assets of the lessee are insufficient to protect the public from damage for which the lessee may be liable arising out of the construction or operation of the pipeline.

(b) For a right-of-way lease granted under this chapter for an oil or natural gas pipeline valued at $1,000,000 or more to be valid and of legal effect, it must contain the terms required to be inserted under the provisions of §§ 110 — 140 of this chapter. An oil or natural gas pipeline right-of-way lease granted under this chapter that does not contain the required terms is null and void and without legal effect and does not vest any interest in state land or any authority in the carrier granted the lease.

(c) The commissioner may insert in any right-of-way lease other reasonable provisions and conditions that he determines the public interest requires.

(d) The lease will also contain terms and conditions that are reasonably necessary to obligate the lessee, to the extent reasonably practicable, to

(1) prevent conflicts with other existing uses of the land involving a superior public interest;

(2) protect state and private property interests;

(3) prevent any significant adverse environmental impact, including but not limited to the erosion of the surface of the land, and damage to fish and wildlife and their habitat;

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(4) restore and revegetate during the term and at termination of the lease; and

(5) protect the interests of individuals living in the general area of the right-of-way who rely on the fish, wildlife, and biotic resources of the area for subsistence purposes.

(e) In the event the commissioner proposes to offer a lease or leases to two or more lessees for the same pipeline, the commissioner may include terms in the lease or leases which establish the limit of the obligations and liabilities of each lessee arising under this chapter or under the lease or leases.

(f) The commissioner may, at his discretion, include any or all of the terms set out in this section in leases of state land for products pipeline right-of-way purposes. (§ 1 ch 72 SLA 1972; am § 11 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.130. Right-of-way easements or leases acquired from others. (a) The lessee may, if the commissioner delegates the function to it, condemn, by declaration of taking, under AS 09.55.420 — 09.55.450, real property and acquire leases of or easements or rights-of-way on lands in the state required for right-of-way purposes for a pipeline subject to the lease on behalf of and as agent for the state in which title to or interest in the land shall vest.

(b) The lease shall contain a covenant that the land, right-of-way, or easement acquired under this section is or will form part of the land leased to the lessee. (§ 1 ch 72 SLA 1972; am § 12 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote subsection (a), deleting the paragraph designations and deleting the provisions of former paragraphs (1) and (2). The amendment also, in subsection (b), substituted "The lease shall contain a covenant" for "The lease covenant required by this section shall be accompanied by a provision" and deleted "carrier" following "lessee."

Quoted in Arco Pipeline Co. v. 3.60 Acres, More or Less, Sup. Ct. Op. No. 1177 (File No. 2419), 539 P.2d 64 (1975).

Sec. 38.35.140. Payment of rental and costs. (a) The lease price for a right-of-way lease shall be the annual fair market rental of the state lands included in the right-of-way based on the appraised fair market value of the land. The lease price is payable annually in advance on or before the anniversary of the lease. The appraised fair market rental value shall be adjusted periodically under the provisions of AS 38.05.015. Rental may not be charged for any land acquired by the lessee under § 130(b) of this chapter and conveyed without cost to the state.

(b) The lessee shall reimburse the state for all reasonable costs incurred in monitoring the construction of the pipeline on the right-of-way. (§ 1 ch 72 SLA 1972; am § 13 ch 3 FSSLA 1973)

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Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.150. Additional provisions of lease.

Repealed by § 14 ch 3 FSSLA 1973.

Editor's note. — The repealed section derived from § 1, ch. 72, SLA 1972.

Sec. 38.35.160. Transfer of right-of-way lease, certificates, or pipeline.

Repealed by § 15 ch 3 FSSLA 1973.

Editor's note. — The repealed section derived from § 1, ch. 72, SLA 1972.

Sec. 38.35.170. Forfeiture of lease. Failure to begin construction of the pipeline facility within a reasonable time of the granting of a right-of-way lease under this chapter for reasons within the control of the lessee or failure of an owner of an interest in the granted right-of-way substantially to comply with the terms of the right-of-way shall be grounds for forfeiture of the right-of-way interest of the lessee or owner in an action brought by the commissioner in the superior court. Before the commencement of any action for forfeiture of an interest in a right-of-way under this section, the commissioner shall give the lessee or owner of the interest notice in writing of the alleged default and shall not commence the proceeding unless the lessee or owner of the interest has failed to initiate good faith efforts to cure the default within 60 days of the notice of the alleged default. (§ 1 ch 72 SLA 1972; am § 16 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.180. Suits to enjoin or recover damages for defaults.

(c) Neither this section nor the state's obtaining an injunction or recovering penalties extinguishes any civil cause of action arising out of a violation of this chapter or the provisions of a right-of-way lease. (am § 17 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment, in subsection (c), deleted "or criminal responsibility" following "civil cause of action" and "or certificate under a lease" following "a right-of-way lease," inserted "or the provisions of," and deleted the former second sentence.

As the rest of the section was not affected by the amendment, it is not set out.

Sec. 38.35.190. Application of the Administrative Procedure Act.

(a) AS 44.62.010 — 44.62.320, 44.62.640 and 44.62.650 apply to

AGO 801596

regulations adopted by the commissioner under the authority of this chapter.

(b) Repealed by § 18 ch 3 FSSLA 1973.

(c) Repealed by § 18 ch 3 FSSLA 1973.

(d) Repealed by § 18 ch 3 FSSLA 1973. (§ 1 ch 72 SLA 1972; am § 18 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment repealed subsections (b), (c), and (d).

Sec. 38.35.200. Judicial review of decisions of commissioner on application. (a) An applicant or competing applicant or a person who has a direct financial interest affected by the lease who raises objections within 60 days of the publication of notice under § 70 of this chapter are the only persons with standing to seek judicial review of a decision of the commissioner under § 100 of this chapter.

(b) The only grounds for judicial review of a decision of the commissioner are

(1) failure to follow the procedures set out in this chapter; or

(2) abuse of discretion so capricious, arbitrary or confiscatory as to constitute a denial of due process. (§ 1 ch 72 SLA 1972; am § 19 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Sec. 38.35.205. Lease savings clause. A judicial finding that any term or condition of a right-of-way lease issued under this chapter is unlawful or invalid may not operate to invalidate the lease or any other term or condition of the lease. (§ 23 ch 3 FSSLA 1973)

Sec. 38.35.210. Delegation of commissioner's authority. The commissioner may delegate to an employee of the Department of Natural Resources or the Department of Law the authority granted under this chapter, except for the authority to execute leases. (§ 1 ch 72 SLA 1972; am § 20 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment deleted "and certificates" following "leases" at the end of the section.

Sec. 38.35.220. Continued operation of certain carriers.

(d) Repealed by § 21 ch 3 FSSLA 1973.
(am § 21 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment repealed subsection (d).

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Sec. 38.35.225. Binding effect of covenants. By entering into a lease under this chapter, the lessee is bound by all the covenants provided for in the lease to the full extent of the power of the state to impose those covenants under its authority as owner of the land to be leased or under its police or regulatory powers or otherwise; provided that the right of the lessee to challenge the power of the state to require such a covenant as owner of the land to be leased or under its police or regulatory powers or otherwise is preserved until such time as action to enforce the covenant is taken by the state. (§ 23 ch 3 FSSLA 1973)

Sec. 38.35.230. Definitions. In this chapter

(1) "commissioner" means the commissioner of natural resources;

(2) "coordinate agencies" includes Department of Labor, Department of Highways, Department of Environmental Conservation, and the Alaska Pipeline Commission;

(3) "lease" means the instrument or extension of an instrument issued under this chapter granting a leasehold interest in state land for pipeline right-of-way purposes to a person and authorizing the construction or operation of, or transportation, service or sale by a pipeline for crude oil, natural gas, or products;

(4) "lessee" means a person or persons holding a valid lease issued by the commissioner;

(5) "natural gas" includes all hydrocarbons produced at the wellhead not defined as oil;

(6) "oil" includes crude petroleum oil and other hydrocarbons regardless of gravity which are produced at the wellhead in liquid form and the liquid hydrocarbons known as distillate or condensate recovered or extracted from gas, other than gas produced in association with oil and commonly known as casinghead gas;

(7) "pipeline" or "pipeline facility" means all the facilities of a total system of pipe (whether owned or operated under a contract, agreement, or lease) used by a carrier for transportation of crude oil, natural gas, or products for delivery, for storage, or for further transportation, and including all pipe, pump or compressor stations, station equipment, tanks, valves, access roads, bridges, airfields, terminals and terminal facilities, including docks and tanker loading facilities, operations control center for both the upstream part of the pipeline and the terminal, tanker ballast treatment facilities, and fire protection system, communication system, and all other facilities used or necessary for an integral line of pipe, taken as a whole, to effectuate transportation, including an extension or enlargement of the line;

(8) "product" means refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, gas oil, casinghead gasoline, natural gas gasoline, naphtha, distillate, gasoline, kerosene, benzine, wash oil, waste oil, blended gasoline, lubricating oil, blends or mixtures of petroleum and any liquid product or by-product derived from crude petroleum oil or natural gas;

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(9) "state land" means

(A) "state lands" as defined in AS 38.05.365;

(B) public land of the United States selected by the state under sec. 6 of the Alaska Statehood Act of 1958 (PL 85-508; 72 Stat. 399), as amended, and real property of the United States transferred to the state under secs. 21, 35 and 45 of the Alaska Omnibus Act of 1959 (PL 86-70; 73 Stat. 141), as amended;

(C) any interest owned by the state in land;

(10) "transportation" means the shipment or carriage by a pipeline of crude oil, natural gas, or products from an upstream terminus in one or more fields or points of production or supply of the minerals to a downstream terminus in one or more points for delivery of the minerals to a purchaser or consignee, for storage, or for further carriage or shipment, including shipment or carriage within the state that may be classified as interstate or foreign transportation to the extent that the transportation may constitutionally be subjected to the provisions of this chapter, as well as all services necessary to effectuate shipment or carriage, including, among other things, the receipt, storage, processing, handling, transfer in transit, forwarding, and delivery of the minerals. (§ 1 ch 72 SLA 1972; am § 22 ch 3 FSSLA 1973)

Effect of amendment. — The 1973 amendment rewrote this section.

Chapter 40. Local Hire Under State Leases.

Section	Section
30. Resident employment	70. Penalties
40. Reporting provisions	80. Injunctive relief
60. Hearings and investigations	90. Definitions

Sec. 38.40.030. Resident employment. (a) In order to create, protect and preserve the right of Alaska residents to employment, the commissioner of natural resources shall incorporate into all oil and gas leases, easements or right-of-way permits for oil or gas pipeline purposes, unitization agreements, or any renegotiation of any of the preceding to which the state is a party, provisions requiring the lessee to comply with applicable laws and regulations with regard to the employment of Alaska residents, a provision requiring the employment of qualified Alaska residents, a provision prohibiting discrimination against Alaska residents and, when in the determination of the commissioner of natural resources it is practicable, a provision requiring compliance with the Alaska Plan, all in accordance with the provisions of this chapter.

(b) All employment falling within the purview of § 50 of this chapter shall be filled by Alaska residents if they are qualified and available. The commissioner of labor, whose decision is final as to residency, shall determine the resident status of individuals for purposes of this chapter

AGO 801599

Sec. 38.05.321. Restriction on sale or lease or other disposal of agricultural land. No state land classified as agricultural land may be sold, leased or otherwise disposed of in a manner inconsistent with § 69 of this chapter. (§ 3 ch 71 SLA 1976)

Sec. 38.05.323. Tidelands seaward of public recreational sites. (a) Notwithstanding any other provision of law, a home rule or general law municipality which accepts by conveyance or other disposition from the state a public recreation area facility developed under the terms of P.L. 507 (70 Stat. 130), upon application, shall receive by conveyance from the director all land owned by the state seaward of the public recreation area facility which is between the mean high tide line and the mean low tide line. The director may promulgate necessary regulations providing for the conveyance of land under this section.

(b) Interests obtained by lease for shore fisheries development, sale, permit or lease for mineral exploration, development, or extraction, or for any other purpose, before August 13, 1974, are affected by this section only on the date of their expiration or termination. (§ 1 ch 108 SLA 1974)

Sec. 38.05.325. Homestead entry.

Cross reference. — As to reservation to which contracts for sale, lease or grant of state land and deeds to state land, properties or interest to state land are subject, see AS 38.05.125.

Sec. 38.05.330. Permits. The director, without the prior approval of the commissioner, may issue permits, rights of way or easements on state land for roads, trails, ditches, field gathering lines or transmission and distribution pipelines not subject to AS 38.35, telephone and transmission lines, log storage, oil well drilling sites and production facilities for the purposes of recovering minerals from adjacent lands under valid lease, and other similar uses or improvements, or for the limited personal use of timber or materials. The commissioner, upon recommendation of the director, shall establish a reasonable rate or fee schedule to be charged for these uses. In the granting, suspension or revocation of a permit or easement of lands, the director shall give preference to that use of the land which will be of greatest economic benefit to the state and the development of its resources. However, first preference shall be granted to the upland owner for the use of a tract of tideland, or tideland and contiguous submerged land, which is seaward of the upland property of the upland owner and which is needed by the upland owner for any of the purposes for which the use may be granted. (§ 7 art III ch 169 SLA 1959; am § 7 ch 61 SLA 1960; am § 4 ch 72 SLA 1972; am § 28 ch 3 FSSLA 1973; am § 13 ch 257 SLA 1976)

AGO 801600

APC

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 Anchorage, Alaska 99502 / Phone (907) 277-5551
Telex 25-187

April 15, 1977

Mr. Don Wold, Executive Director
Alaska Oil and Gas Development Advisory Board
Department of Natural Resources
State Office Building
Juneau, AK 99811

Dear Don:

In response to your requests this week, we are writing to summarize and describe the essence and the effect of the contract(s) executed by the State and Phillips and Alaska Pipeline Company (APC) regarding the taking in kind of the State's royalty gas (1/8th) from the North Cook Inlet Gas Field.

By way of background, APC's supply until now has come entirely from the Kenai gas field, which is owned by Union and Marathon. We have had two supply contracts: one for Anchorage, in which delivery to us is at the Kenai gas field; and one for the North Kenai Road ("Nikiski") area, in which delivery to us is at or near the Kenai LNG plant.

The "Anchorage" contract is for a total of 550 BCF (billions of cubic feet) to be taken (take or pay for) at 26 BCF/year (which is 72,000 MCFD--72,000 thousand cubic feet per day) by December 31, 1992, but with deliverability of 160,000 MCFD on any day through December 31, 1985. The basic price for this gas is 24¢ per MCF until January 1, 1981, then 27¢ until January 1, 1986, and then the defined "area price" for the remainder of the contract term. In addition to this basic price we pay 19.5¢ per MCF for the extra deliverability described above, and the

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19.5¢ is adjusted each January 1 by the ratio of the published Wholesale Price Index (WPI) of the preceding November to the WPI of November, 1974. At present, the total cost for gas under this "Anchorage" contract is 45.1¢ per MCF.

The "Nikiski" contract was for 10 BCF to be delivered from May 1, 1967 to April 30, 1977, with deliverability of 10,000 MCFD, no take or pay, and priced at 1.5¢ higher than the basic price for "Anchorage" reserves as described above. We used the last of the 10 BCF under this contract in August of 1976, and thereafter we began taking "Anchorage" reserves at Nikiski, priced at the total price of "Anchorage" reserves plus 1.5¢ per MCF, temporarily (one year was agreed) pending resolution of a longer term supply. We had expected to be using North Cook Inlet royalty gas as the replacement for "Anchorage" reserves at Nikiski, and still expect to be doing so upon the implementation of the royalty gas contracts as revised this year.

We selected North Cook Inlet royalty gas because we believed, and still believe, this gas will be available to us and our customers at a lower price than any other "new" reserves. This gas is under contract (as LNG) to June 1, 1984 for export to Tokyo and its cost to us is approximately 75¢ per Mcf immediately, rising to 85¢ when compressors are installed, with certain escalation as described in the revised contracts. In comparison, Pacific Alaska LNG is offering $1.45 for similar gas from Cook Inlet (without the same deliverability of our "Anchorage" reserves), with escalations. We do not have proof of the $1.45 pricing, but it can be verified by the State. Thus, we see the royalty gas to be available

to us at less than half the going price of "new" gas in the Cook Inlet area, delivered on the North Kenai Road.

Our alternative to competing at the $1.45 price level is to continue to utilize "Anchorage" reserves at Nikiski, as we are now doing, but to pay the same price we would have paid for royalty gas. We have verbal assurance that we can operate on this basis at Nikiski while we install the facilities necessary to shift to royalty gas, and we are proceeding with preparations to do so at the earliest possible date following legislative approval of the royalty contracts as revised. We hope to begin taking royalty gas as early as June, 1977.

Several questions arose over the two years it has taken to reach agreement of the several parties as to our use of royalty gas, and I will try to comment as information for those who review the actions taken. First, the royalty gas contract signed last year, and approved by the legislature, was contingent on APC working out an arrangement with Phillips to obtain delivery of the royalty gas through their pipeline from the platform to the Kenai LNG plant, and it required "take or pay" of 100% of the royalty gas. These elements led to problems which had to be resolved as has been done in the revised contracts which were executed last week. The differences are (1) that the delivery to shore will be made by Phillips for the State, with APC paying Phillips for the account of the State, at prices negotiated by APC with Phillips, and (2) that there will be no "take or pay": Phillips will make a best effort to deliver at least 3 BCF per year (roughly 55% of the total royalty), and APC will make a best effort to take all of the royalty which Phillips

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can deliver, but neither party will be obligated to make extra investment or incur unreasonable extra operating cost.

Without obligation, APC expects Phillips to deliver essentially all the royalty and expects to take all the royalty, but only experience will tell the outcome of this expectation. Phillips may install one or more units of compression, and APC may install a pipeline to connect the royalty gas into its pipeline to Anchorage. Various factors outside the respective control of Phillips and APC have made it necessary to develop a best-efforts arrangement rather than the original "take or pay" of 100% of the royalty.

What would these "various factors" be?

APC's royalty pipeline, if built, would provide several advantages:

1. It would essentially assure APC's ability to take all of the available royalty gas, all of the time, and gain the maximum benefit from royalty gas.
2. It would provide "back-up" for APC's North Road customers while royalty gas may not be available due to downtime of the LNG plant, the platform, or the Phillips pipeline or compressors.
3. It would provide APC with access to other than royalty gas in the vicinity of the Kenai LNG plant, which is at the center of several streams of natural gas--supplies to Swanson River for repressurizing, ammonia/urea manufacture, Pacific Alaska LNG, etc. Thus, the pipeline could give APC additional options on "new" gas from various sources.

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4. It would provide an independent supply of gas to APC for emergency in the event of catastrophic failure of the Kenai gas field--well operations, dehydration, or compression--or of APC's pipeline from the field to Mile 16 of APC's pipeline to Anchorage.

Feasibility of the royalty pipeline depends on the possibility of exchanging royalty gas with Union-Marathon, final rate decisions of the Alaska Public Utilities Commission (APUC), final quantification of the amount of royalty gas to be delivered, flow through of the extra cost of royalty gas, and other factors including availability and cost of right of way. At present it appears that there is sufficient benefit from the royalty line to justify the investment by APC.

APC's experience with the APUC is such that royalty gas is particularly attractive: the flow through of its extra cost to end users has been authorized by the APUC, whereas no other purchase by APC can be made with flow through except by further hearings. This fact, plus the fact that it appears royalty gas will always be available (for the contract term) at less cost than any other likely "new" gas, make the royalty most advantageous to APC and its customers. Further, the precedent of this purchase of this royalty gas by APC should be helpful at a future date when other royalty gas may become available and feasible for purchase by APC.

It is clear that APC's action to purchase royalty gas is in the public interest. The price is the lowest available to APC and its

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customers; the price is qualified to be not less than the State would have received by its continued export to Japan or by any comparable sale during the contract term within 100 kilometers of the Phillips platform; and a relatively modest investment is required by APC even including the royalty pipeline. Other "new" gas could involve meeting the currently competitive price of Cook Inlet gas ($1.45) and could involve pipeline costs or take or pay costs many times that for royalty gas. The quantity of this royalty gas is rather ideal for APC's present requirements. In 1976, APC's total purchases were 28.6 BCF compared to the required take or pay quantity of 26 BCF per year at the Kenai gas field. As structured, the royalty gas contracts would allow APC (and Phillips) to match their investment to market developments and thus provide the optimum conditions for such investment.

Clearly, Phillips has been a reluctant party in these contracts but has acted responsibly and reasonably and consistent with the public interest. Phillips preference has always been to retain the royalty gas and increase its value by liquefaction for export to Japan. That contract was originally 52¢ FOB Tokyo, but now is $1.95. Clearly the increase ($1.43) contains a substantial increase of profit (which is shared by the State through its royalty price). Clearly the 20¢ revenue which Phillips will realize by bringing the royalty gas on shore does not compare with the revenue and income Phillips would realize by its export.

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The 20¢ delivery/compression charge is obviously the most Phillips could charge, because it is the most APC would pay. The State is realizing the most it can from the royalty gas, because APC will not pay more for this gas. To suggestions, if any, that APC should not have accepted the delivery charge as contracted, APC would respond that it would be no more logical to require Phillips to accept less than their required price than for the State to accept less than it deems to be necessary for this gas.

APC will not increase its income by purchasing this royalty gas--it will simply recover most (not all) of its costs, by flow through. APC's objective in making this purchase is to prolong the life of its gas reserves and thus the availability of its "old" gas at "old gas pricing" for its customers.

APC firmly believes that the merit of its purchase of royalty gas has been established already in various arenas.

1. The APUC considered the subject in extensive hearings in 1975 and its order clearly contemplates the purchase and in fact, deemed the matter to be of urgent importance.
2. The Royalty Board and the Commissioner of Natural Resources have reviewed this matter at great length and have approved and authorized its present form.
3. The Attorney General has reviewed jursidictional aspects and agreed it is not contrary to the public interest or the laws of Alaska.

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4. The legislature, in its prior approval, has endorsed the concept and pricing of this purchase by APC.

Previously, support for this purchase by APC was given by the City of Anchorage, Chugach Electric Association, and Homer Electric Association. APC is not aware of any opposition to its purchase of this royalty gas (opposition by Pacific Alaska LNG was withdrawn in 1976, at the insistence of APC). When these various governmental and business approvals are considered, and when the alternative can only be that this gas would continue to be exported to Japan, APC believes that ample justification for the contracts has been made.

At present, APC has about 415 BCF of gas remaining under contract at the Kenai gas field. At 30 BCF per year, there would be 14 years of reserves now remaining. The royalty gas potentially available to June, 1984 is about 40 BCF, which is less than a 10% increase. APC is and has been attempting to reduce the growth rate of its gas sales through conservation measures such as waste heat recovery by power plants and by opposing and reducing the use of gas-generated electric heat. However, it is very likely that unavoidable growth will shorten APC's reserve life to 10 years or less. APC must look to the long term aspects of its gas supply in order to avoid future shortages and problems with the long-term (20 year) financing APC requires. Purchase of the royalty gas is a step, but only a step, in this direction. Royalty gas at 75¢ or 85¢ will be helpful to APC in its negotiations for additional "new" gas reserves, viewed in the context of competitive offerings at $1.45 or possibly a price equivalent to oil in future years.

best estimate / judgement DT 4/18/77

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Delays in obtaining royalty gas can only diminish its benefit to APC and its customers because of the quantity available as well as the timing and impact of the purchase.

Very truly yours,

Dale Teel
President

DT/pm

?
Board file AK Pipe

Mr. Donald Wold, Executive Director
Oil and Gas Royalty Advisory Board
Department of Natural Resources
State of Alaska
Juneau, AK 99801

April 6, 1977

subject: the proposed contract between State of Alaska and Phillips Petroleum Company for North Cook Inlet royalty gas

Dear Don:

After reading the draft contract attached to this letter, I am required to inform you that I believe this contract to be severely prejudicial to the natural gas consumers served by Alaskan Pipeline Company.

Specifically, I am troubled by Article 9.1, Article 9.2, and Article 11.1. These articles establish a basic cost of service, an escalation factor to be applied to this basic cost of service, a provision for higher costs of service due to compressor costs, and an exemption of this natural gas transmission system from Alaska Public Service Commission control.

I have seen no justification that a pipeline costing 10 to 12 million dollars perhaps 9 years ago (which is most probably highly depreciated) should have a cost of service of 10¢ per Mcf. Regarding the rate of escalation to be applied to the basic rate (i.e., 6 per cent per annum), I would like to point out that in all cost of service projections which I have made show declining transportation charges through time even given a general inflation rate of 6 per cent. I am unaware that future compression costs for State of Alaska royalty gas separate from net working interest gas will require payment on the basis of 10¢ per Mcf and inflated each year thereafter at 6 per cent. In short, the underlying economics of the above mentioned contract should be worked out prior to signing the contract. This is especially so given the fact that contract Article 11.1 frees Phillips from Alaska Public Service Commission supervision.

The delay required by this staff work should not be lengthy.

RECEIVED
APR 07 1977
ALASKA ROYALTY
OIL & GAS BOARD

Sincerely,

David L.T. Knudson

David L.T. Knudson
7510 Chad
Anchorage, AK 99502

AGO 801611

period extending back one-half of the time elapsed since the last previous test, not exceeding, however, fifteen (15) days.

8.5 If for any reason the State's or its designee's meter is out of service or is found registering inaccurately and the error is not determinable by ordinary test such that the volume of gas delivered through such meter cannot be ascertained or computed from the readings thereof, the volume of gas so delivered during the period the meter is out of service or registering inaccurately shall be estimated and agreed upon by the parties hereto upon the basis of the best available data, using the first of the following methods which is feasible:

(a) by correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation;

(b) By using the registration of any check measuring equipment of Lessee if installed and registering accurately;

(c) By estimating the volume by comparing it with deliveries during preceding periods under similar conditions when the meter was registering accurately.

ARTICLE IX

GATHERING AND COMPRESSION CHARGES AND TAXES

9.1 For all gas delivered by Lessee to the State at the delivery point, the State or its designee shall pay

a) ((

to Lessee a gathering charge of ten cents (10.0¢) per Mcf from the date of first delivery hereunder. The above-stated charge shall increase by six percent (6%) compounded annually, on each anniversary date of the date this Agreement.

9.2 It is recognized by the parties hereto that it may be necessary for Lessee to install compression facilities during the term of this Agreement. At the time the first compressor unit is installed and first used, the State or its designee shall pay Lessee in addition to the gathering charge set forth in Section 9.1, a) a compression charge of ten cents (10.0¢) per Mcf for all gas delivered by Lessee to the State at the delivery point. Such charge shall increase by six percent (6%) per year, compounded annually, commencing on the first anniversary of the date of such compression facilities are installed and first used.

9.3 In the event that Lessee installs or causes to be installed from time to time compression facilities in addition to the first compressor unit mentioned in Section 2, above, Lessee shall give the State and its designee written notice at least six (6) months prior to the time Lessee anticipates placing any additional unit or units in operation in order to maintain capacity in its gathering system. b) Such notice shall also terminate this agreement at the end of such six (6) months period. If, within ninety (90) days of the date of such notice the parties shall agree upon a new compression charge to be applicable when such additional compression facilities go into operation, then this agreement shall not terminate but shall continue in full force and effect as amended to include the new compression charge.

for such month, Lessee shall determine the amount of royalty gas not taken by the State for such month and shall make payment therefor to the State together with said statement.

10.3 Each party hereto shall have, at its expense, the right to examine the books and records of the other party to the extent necessary to verify the accuracy of any statement or invoice made under or pursuant to this contract. Any statement shall be final as to both parties unless questioned in writing within two (2) years after payment thereof has been made.

ARTICLE XI

REPRESENTATION AND CONDITION PRECEDENT

11.1 It is expressly recognized and agreed that the gas gathering system utilized for deliveries hereunder is operated and maintained by Lessee for its own purpose and Lessee does not, by entering into this Agreement, dedicate any facilities or otherwise undertake to render any service to or for the public. This Agreement is being undertaken solely to effectuate the delivery of royalty gas to the State, and the State makes the material representation that neither this Agreement nor the State's use or disposition of the gas delivered hereunder will subject Lessee to regulation by the Federal Power Commission, the Alaska Public Utilities Commission, or the Alaska Pipeline Commission.

(10)

11.2 In the event that any governmental agency shall declare that Lessee's activities hereunder subject Lessee to regulation as a utility, then either party shall have the option to terminate this Agreement upon thirty (30)

STATE of ALASKA

MEMORANDUM

Pete

TO: Don Wold
Executive Director
Alaska Royalty Oil and Gas
Development Advisory Board

DATE: March 29, 1977

FILE NO:

TELEPHONE NO:

FROM: Wilson Condon
Deputy Attorney General

SUBJECT: Jurisdiction of the Alaska Pipeline Commission Over Phillips East Cook Inlet Gas Line

This is in response to your memorandum of March 11, 1977 in which you ask if the Alaska Pipeline Commission (APC) would have jurisdiction over a pipeline operated by Phillips Petroleum if State-owned royalty gas is transported over that pipeline to North Kenai Road, where it would be sold by the State to Alaska Pipeline Company, a wholly owned subsidiary of Alaska Gas and Service. My conclusion is that the APC would not have jurisdiction over the Phillips Petroleum Company pipeline.

The Alaska Pipeline Commission has jurisdiction over "pipelines", "pipeline facilities" and "pipeline carriers". AS 42.06.630(10) defines "pipeline carrier" as:

> . . . the owner, including corporations . . ., of any pipeline, as the term is defined in this section, or any interest in it;

AS 42.06.630(9) defines "pipeline" or "pipeline facility" as:

> . . . all the facilities of a total system of pipe . . . in this state used by a pipeline carrier for transportation, for hire and as a common carrier, of oil or gas for delivery, storage, or further transportation, and including all pipe, pump and compressor stations, station equipment, and all other facilities used or necessary for an integral line of pipe to effectuate the transportation from point to point, excluding, however, gas processing plant, heaters and separators;

The salient portion of the above definition is written in the conjunctive, i.e., to be a "pipeline" or "pipeline facility" under the Alaska Pipeline Commission Act, AS 42.06 et seq., a pipeline facility must be used ". . . for transportation, for hire and as a common carrier . . ." (emphasis added).

Of course Phillips, in the arrangement described at the outset of this memorandum, will be using its pipeline for "transportation" of gas. However, since the subject pipeline is neither operated by Phillips "as a common carrier" nor is it subject to the "common carrier" covenant requirement of AS 38.35.120 due to the fact that the lease of state lands for the subject pipeline pre-dates the enactment of that statute, the subject pipeline would not fall within the jurisdiction of the APC were the proposed arrangement to be entered into by Phillips.

WLC:RMB:jec

STATE
of ALASKA

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES
OFFICE OF THE COMMISSIONER

TO:

Wilson Condon
Deputy Attorney General

DATE : March 11, 1977

FROM:

Don Wold
Executive Director
Alaska Royalty Oil and Gas
Development Advisory Board

SUBJECT: Jurisdiction of the Alaska Pipeline Commission over the Phillips Petroleum Company pipeline.

Please refer to Commissioner Martin's memo to the Attorney General dated February 24, 1977 and your response dated March 7, 1977 regarding the same subject except as related to the Alaska Public Utilities Commission.

We would sincerely appreciate you review and opinion of the same matter except as related to the Alaska Pipeline Commission.

cc: Fred Boness

Don

FYI 3/17/77

John (W) received the State-Phillips draft by telecopy Friday afternoon. He did not receive the State-Pipeline draft due to breakdown of our X-cop telecopier. Dis sending it, plus the AG opinion today by airmail special delivery. Have no idea when they will get it, but couldn't do better by Goldstuck & otherwise!

Wade

ALASKA PIPELINE COMPANY

Dale Teel
President

March 10, 1977

Dear Don:

I've managed to write three pages, giving my rationale regarding the charges by Phillips.

I also enclose for your personal information copies of the transmittal letter on Chugach's latest rate increase filing and an internal memo I wrote on that subject. While the Chugach's letter is public information, at the APUC, I believe it would be best not to publicize it out of your office and certainly my comments on that matter need to be restricted.

I hope this material will help you bring our negotiations to fruition.

Cordially,

cc: Mr. John Horn w/attachments

RECEIVED
[illegible]
OIL [illegible]

RECEIVED
MAR 14 1977
ALASKA ROYALTY
OIL & GAS BOARD

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 / Anchorage, Alaska 99502

March 10, 1977

Memo to: File

Subject: Rationale for Accepting Gathering and Compression Charges Proposed on North Cook Inlet Royalty Gas

By telephone March 10, 1977 Mr. Don Wold asked us to rationalize the acceptance of a 10¢/MCF charge for "gathering" and a 10¢/MCF charge for compressing royalty gas we have negotiated to purchase from the State of Alaska.

The State will escalate the price we pay for royalty gas to the highest price paid by other purchasers within 100 kilometers for similar quality and similar delivery conditions. We had offered to pay no more than the price the State would otherwise have received through the continued export of the royalty gas to Japan as LNG.

It thus is clear that the State places the State's interest above the interests of our ratepayers to the extent we have to pay more than would result from export of this gas. It does not follow that the Lessee who has made the investment required for production, gathering, and compression of royalty gas can be or should be held responsible to deliver the royalty gas at less cost than the Lessee determines to be necessary, fair, and reasonable. In fact, efforts by the State to do so will simply result in there being no agreement and no delivery of royalty gas by the Lessee.

The Lessee cannot be treated as a regulated operator under Alaska law, and the Lessee has the right to determine whether or not, and at what price, it is willing to share its facilities and install new facilities for the benefit of our ratepayers rather than for its shareholders. Clearly, the Lessee prefers not to share these facilities and will not do so if effort is made to assert that delivery of royalty gas onshore could have equal or greater priority than its contractual duty to deliver LNG to Tokyo, regardless of the revenue (price) received by Lessee.

The Lessee has provided (letter of 3-3-77) some cost estimates, reluctantly, to show the reasonableness of the prices accepted by us:

Table I: Pipeline (Gathering)

Annual cost is reported to be $7,070,000. Assuming all this cost is carried by 43 BCF or 55 BCF, the average cost is 16.4¢ or 12.9¢. The selection of 10¢ as being appropriate for gathering

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 / Anchorage, Alaska 99502

royalty gas is less than these average costs, but clearly more than the incremental cost, as it must be. There is no way for a third party to impose a different price on the Lessee, and the price of 10¢ is far below any alternative available to us. In fact, there is no such alternative except not to take royalty gas, and we are not obliged to do so. We bear all the risk that the cost of this gas will remain competitive and will be recoverable through our revenues.

Table II: Compressors (first unit)

Annual cost is reported to be $2,010,000. Assuming all this cost is carried by 43 BCF or 55 BCF, the average cost is 4.67¢ or 3.65¢. While the compression is not required except to deliver royalty gas (but all the gas must be compressed), the incremental cost here would be 37.2¢ or 29.1¢. However, the Lessee recognizes that during the contract term compression will be required even if royalty gas is not being delivered to us. The selection of 10¢ as being appropriate for the compression is less than the short term incremental cost but well more than the average cost. Again, there is no way for a third party to impose a different price on the Lessee, and we bear all risk that the cost of this gas will remain competitive and will be recoverable through our revenues.

If the two components are combined, the results are:

$9,000,000 annual cost @ 43 bcfy

21.12¢ average cost

versus 20.00¢ price requested

The price requested is below the reported average cost. Assuming no incremental cost for gathering (pipeline) however, the price requested is well above the incremental cost. In fact, there is an incremental cost for gathering (as to dehydration), and other down-hole expenses which are a function of production rate. We are not equipped to quantify these costs and there is no reason to do so. The essence of this matter is that the Lessee has offered us a price below average cost and above incremental cost which is acceptable to us and that we are the only party at risk.

AGO 801621

3/9/77

2/14/77

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General Offices Located at 3000 Spenard Road
P.O. Box 6288 / Anchorage, Alaska 99502

There are only two beneficiaries of this contract. We do not benefit, since we will simply recover our added costs from our rate payers. We believe Phillips will not benefit since they are reluctant and clearly prefer to process and ship the gas to Japan. We believe their profits in processing and selling the royalty gas to Japan would be much greater than the amount of income from the proposed compression and transmission charges net of incremental expenses. The State takes no risks and may benefit from a higher wellhead price. Our ratepayers benefit from the increased life of our committed reserves. If the transaction is not consummated then, the losers are the State and our ratepayers, which (through power distribution) include more than half of the State's population, from Homer and Seward to Talkeetna.

There is no way to require the Lessee to deliver royalty gas (at any price) and no way to disagree with the price(s) now offered. Clearly the end objective -- obtaining of royalty gas -- is in the public interest, and the State should place that interest foremost.

dh

cc: Fred Boness
Royalty Board

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 Anchorage, Alaska 99502 / Phone (907) 277-5551
Telex 25-187

March 9, 1977

Mr. Don Wold, Executive Director
Royalty Oil & Gas Development
Advisory Board
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Dear Don:

As requested at the meeting of the Board on March 7, I enclose the pertinent extract (pages 1,8,9,10) from Order No. 3 in Docket U-75-68 dated 17 December, 1975.

You will note on page 10 that we were expected to be taking royalty gas prior to August 1, 1976. We explained the status of this matter by letter of September 29, in response to their inquiry. I surely hope that now, nearly 6 months later, we will be able soon to conclude the negotiations and proceed to begin taking royalty gas this year. Clearly, the Commission is convinced of our imperative need to obtain more reserves and has approved flow through of the cost. Copy of the complete order was mailed to the Attorney General, and to each legislator, by the Commission. I believe we will have no difficulty getting approval of the amended contract.

APUC does not speak to the matter of transportation chg, compression, etc.

Very truly yours,

Dale Teel

Dale Teel

dh

Enclosures: Pages 1,8,9,10 and Mailing List of Order No. 3, U-75-68
Letter to APUC dated September 29, 1976

AGO 801623

RECEIVED
MAR 11 1977
ALASKA ROYALTY
OIL & GAS BOARD

STATE OF ALASKA

THE ALASKA PUBLIC UTILITIES COMMISSION

Before Commissioners: Gordon J. Zerbetz, Chairman
B. Richard Edwards
Marvin R. Weatherly
Carolyn S. Guess (not participating)
Susan M. Knowles

In the Matter of the Filing of a Tariff Revision, Designated as TA12-4, by ALASKA GAS AND SERVICE COMPANY to Adopt Purchased Gas and Tax Adjustment Clauses	)	U-75-68
	)	ORDER NO. 3

ORDER MODIFYING PURCHASED GAS COST AND TAX FLOW THROUGH CLAUSES AND ACCEPTING MODIFIED CLAUSES

On July 31, 1975, ALASKA GAS AND SERVICE COMPANY (AGAS), a division of Alaska Interstate Company, filed a tariff revision to reinstate in its natural gas utility tariff its tariff rules Nos. 708 and 709. These sections would allow AGAS to flow through to its customers, by means of a billing surcharge, any increase in its wellhead cost of gas above 41.5¢ per MCF occurring after July 1, 1975, and any new or increased tax or excise imposed by Federal, State, Borough, Municipal or other local taxing authority upon the production, transmission, or sale of gas, or levies of special taxes, license fees, or street or right-of-way levies or fees, above the amounts established on January 1, 1975.

Order No. 1 in this proceeding suspended the tariff revision until March 1, 1976. In Order No. 1 the Commission also established a hearing date of October 30, 1975. AGAS was to bear the burden of proof that the tariff revision requested was reasonable and proper in all respects.

AGO 801624

will be tailored as much as possible to enable the gas cost increases based on the wholesale price index to be flowed through in a timely manner.

Where a flow through will not result in AGAS maintaining or receiving more than a reasonable rate of return on its investment it is the opinion of this Commission that the flow through should be permitted. The basic reason for flow through provisions is to insure that a short term windfall does not accrue to the customers of AGAS in rates which do not properly reflect the revenue requirements of AGAS. Such a windfall would result from short term regulatory lag. When designing flow through clauses or allowing the flow throughs pursuant to the clauses the Commission must insure that windfall profits do not accrue to AGAS. Each of the flow through clauses acceptable to the Commission should be applied by AGAS with this in mind. Conservative applications of these clauses should be the norm for AGAS. If the Commission determines that the flow through clauses set forth above in this order including the royalty gas clause are being applied to maintain or receive more than a reasonable rate of return or are otherwise being abused the Commission will commence an investigation to repeal these clauses and order appropriate refunds where applicable.

Royalty Gas

The evidence in this proceeding clearly demonstrates that if AGAS is able to purchase royalty gas from the State of Alaska it will be necessary that AGAS take the gas as it is produced and that the price of this royalty gas will be somewhat higher than the price of gas from other gas

supplies now committed to AGAS. The volume of gas from the State will not meet the entire demand on the system which results in commingling of high and low priced gas. This commingling raises several problems. The initial problem is a month to month change in rates to the consumers of AGAS. The month to month billings would vary directly in accordance with the royalty gas portion of the total gas volume consumed by the customers of AGAS. A higher proportion of royalty gas consumed would result in an increased average cost of gas. In order to prevent a windfall for either AGAS or the customers of AGAS that would result by setting a constant average price, it is the Commission's opinion that the royalty gas may be commingled with the cheaper gas and that the month to month rates of customers of AGAS may vary in accordance with the amount of royalty gas distributed to the customers. Another problem raised with the royalty gas variation involves the conditions under which the royalty gas flow through clause may be used. It is apparent to the Commission that monthly filings of comparative balance sheets, operating expense statements, rate of return calculations and rate base calculations is not practical for the implementation of this clause. It is the Commission's opinion, however, that a report should be filed by AGAS in a form acceptable to the staff of the Commission, that would allow the staff of the Commission to audit the fluctuation of the rates charged for gas to the customers of AGAS. These reports will be due on January 15, April 15, July 15 and October 15 of each year. The information in the report should at least show the total volume of gas consumed for each of the months involved in the report, the volume of

AGO 801626

royalty gas purchased for each month, the price of the royalty gas at the point of purchase by AGAS, and the price and volume of the gas purchased by AGAS from other suppliers.

The method which should be used by AGAS to determine its average cost of gas per MCF is to multiply the amount of State royalty gas purchased in a month times the price of the State royalty gas and add to that product the product of the price and volume of gas purchased from other suppliers in the same month. The sum of the two products should then be divided by the total amount of gas purchased in the month to arrive at the average cost of gas per MCF. It is apparent to the Commission that by using this formula the additional cost of gas per MCF that the customers of AGAS will pay as a result of the commingling of royalty gas with other gas will fall generally in the range of 2 to 5¢ per MCF per month.

It is the Commission's opinion that it is imperative for AGAS to obtain additional reserves and gas supply to serve its customers. If the royalty clause is not used to reflect an average cost of gas on or before August 1, 1976, this Commission will commence an investigation to determine the reasons for the non-use and whether the clause should be deleted from the tariff of AGAS.

Has this been done? See Sept 29, 1976 letter attached

RESERVE TAX

The evidence in this proceeding shows that the gas company may become responsible for the payment to its suppliers of gas of the reserve tax that its suppliers are required to pay the State of Alaska pursuant to 159 SLA 1975. It is the opinion of the Commission that this tax should be treated as an expense of the utility recoupable

AGO 801627

Paul F. Robison, Esquire
921 W. 6th Avenue
Anchorage, Alaska 99501

Mr. & Mrs. Roger Clyne
3011 Lexington Avenue
Anchorage, Alaska 99502

Roger R. Kemppel, Attorney
Municipality of Anchorage
P. O. Box 400
Anchorage, Alaska 99510

Mr. & Mrs. Hostman
Whirlaway Rd. Box 100
Eagle River, Alaska 99577

COURTESY LIST

Alaska Gas & Service Company
P. O. Box 6288
Anchorage, Alaska 99502

City of Kenai
Box 580
Kenai, Alaska 99611

Chugach Electric Association, Inc.
P. O. Box 3518
Anchorage, Alaska 99501

Kenai Utility Service Company
P. O. Box 614
Kenai, Alaska 99611

Kenai Peninsula Borough
P. O. Box 850
Soldotna, Alaska 99669

Cook Inlet Region, Inc.
1211 West 27th Avenue
Anchorage, Alaska 99503

The Honorable Helen D. Beirne
Representative
Box 4-BB
Spenard, Alaska 99503

The Honorable Bob Bradley
Representative
601 North Bragaw
Anchorage, Alaska 99504

The Honorable Thelma Buchholdt
Representative
2607 Kona Lane
Anchorage, Alaska 99503

The Honorable Samuel R. Cotten
Representative
Box 296
Eagle River, Alaska 99577

The Honorable John L. Rader
Senator
Box 2068
Anchorage, Alaska 99501

The Honorable Patrick Rodey
Senator
3605 Lois Drive #11
Anchorage, Alaska 99503

The Honorable Clem V. Tillion
Senator
Box 373
Homer, Alaska 99603

The Honorable Edward C. Willis
Senator
Box 402
Eagle River, Alaska 99577

The Honorable Avrum Gross
Attorney General
Pouch K
Juneau, Alaska 99811

Anchorage Attorney General's
Office
Civil Section
300 K Street
Anchorage, Alaska 99501

Courtesy List (Cont.)

The Honorable Helen M. Fischer
Representative
2023 Wildwood Lane
Anchorage, Alaska 99503

The Honorable Clark Gruening
Representative
940 Tyonek
Anchorage, Alaska 99501

The Honorable H. M. "Mike" Hershberger
Representative
2906 Will Rogers Place
Anchorage, Alaska 99503

The Honorable Ramona M. Kelley
Representative
5214 East 24th Avenue
Anchorage, Alaska 99504

The Honorable Joseph H. McKinnon
Representative
2203 West 46th Avenue
Anchorage, Alaska 99503

The Honorable Hugh Malone
Representative
Box 9
Kenai, Alaska 99611

The Honorable Kathryn Ostrosky
Representative
423 E. 12th Avenue
Anchorage, Alaska 99501

The Honorable William K. Parker
Representative
337 East 10th Avenue
Anchorage, Alaska 99501

The Honorable Leo Rhode
Representative
Box 406
Homer, Alaska 99603

The Honorable Theodore G. Smith
Representative
2616 Sorbus Circle
Anchorage, Alaska 99504

The Honorable Susan Sullivan
Representative
7330 Barge Court
Anchorage, Alaska 99504

The Honorable Richard K. Urion
Representative
3239 Hiland Drive
Anchorage, Alaska 99504

The Honorable H. E. "Brad" Bradley
Senator
P. O. Drawer B670
Anchorage, Alaska 99508

The Honorable Genie Chance
Senator
Box 2392
Anchorage, Alaska 99510

The Honorable Mike Colletta
Senator
Box 3188
Anchorage, Alaska 99501

The Honorable Chancy Croft
Senator
425 "C" Street, Suite 710
Anchorage, Alaska 99501

The Honorable Joseph L. Orsini
Senator
2912 Alder Drive
Anchorage, Alaska 99504

Alaska Gas and Service Company

GENERAL OFFICES LOCATED AT 3000 SPENARD ROAD
P. O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-5551
TELEX 25-187

September 29, 1976

Alaska Public Utilities Commission
1100 MacKay Building
338 Denali Street
Anchorage, Alaska 99501

Dear Commissioners:

Order No. 5 of U-75-68 requires a report on the status of our purchasing royalty gas from the State of Alaska, by October 15. The matter of royalty gas availability was mentioned in Order No. 7 of U-75-95 as part explanation for setting a return on equity of only 14.25% for us, which in our opinion is inadequate.

Negotiations for royalty gas have had to be done intermittently because of the heavy attention required for U-75-95. We have had several meetings with Phillips and others regarding royalty gas, and still have some hope to reach a satisfactory conclusion. Our alternative would be to continue utilizing "Anchorage" reserves to supply our customers in the North Kenai Road area. This would avoid the need for further investment and the higher cost of gas.

If we can anticipate sufficient return and if we can obtain the necessary financing, we would of course want to proceed to obtain royalty gas as being a better, longer-term solution to this matter. But it became less feasible to us and less favorable to the public interest than we once envisioned because of three aspects of the contract with the State (copy which is enclosed):

(1) The price is set to be equal to the highest of the defined area, whereas we hoped it would never be higher than the price of gas to be liquefied for Japan.

(2) The state requires that we take 100% of the royalty gas although we do not have sales on the North Kenai Road for the full amount; we do not have facilities to interconnect with our pipeline to Anchorage; and we are not able to obtain an "exchange" agreement for gas at the Kenai field.

Alaska Gas and Service Company

GENERAL OFFICES LOCATED AT 3800 SPENARD ROAD
P.O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-5551
TELEX 25-187

(3) The contract term is limited to the term of the sale to Tokyo -- June 30 of 1984 -- which sharply limits the feasibility of investing for facilities. We had asked for this royalty for "the life of production."

Phillips has asked that we fund all of the first phase of a compressor station on their platform, estimated at $5 million, as a condition for delivering the royalty to us onshore. We have countered with an offer to pay a pro-rata (volume) share for compression with a right to discontinue after one year's notice, and an offer to resell "excess" royalty gas back to Phillips at the price they would otherwise have paid to the State, and to forego taking royalty gas if (and while) pipeline capacity is a limitation. We will require a standby gas supply during such periods when royalty is not available. We have not been able to obtain such a supply and may have to build a pipeline from our existing line (to Anchorage) for this purpose. It is here that allowable rate of return and financing became essential to the decision.

We do not believe it is practical to develop "a complete record" of the negotiations for the Commission's files on this matter, but we would welcome an opportunity to discuss it informally at the convenience of the Commission. Clearly we do need to preserve the flow through provision in order to continue our negotiations, which apparently will require several more months.

Very truly yours,

Dale Teel
President

dh

Enclosure

STATE of ALASKA

MEMORANDUM

Re: APUC Phillips AK Pipe Co.

TO:

DATE: March 7, 1977

Guy Martin, Commissioner
Dept. of Natural Resources

FILE NO:

TELEPHONE NO:

FROM: Wilson Condon
Deputy Attorney General

SUBJECT: Jurisdiction of the APUC over Phillips Petroleum Pipeline

This is in response to your memorandum of February 24, 1977, in which you ask if the Alaska Public Utilities Commission would have jurisdiction over a pipeline operated by Phillips Petroleum if State-owned royalty gas is transported over that pipeline to North Kenai Road, where it would be sold by the State to Alaska Pipeline Company, a wholly owned subsidiary of Alaska Gas and Service. My conclusion is that the APUC would not have jurisdiction over the Phillips Petroleum Company pipeline.

The Alaska Public Utilities Commission has jurisdiction over "public utilities" which are defined by AS 42.05.70(2) as follows:

> "public utility" or "utility" includes every corporation (whether public, cooperative, or otherwise), company, individual, or association of individuals, their lessees, trustees, or receivers appointed by a court, that owns operates, manages or controls any plant, pipeline or system for
>
> * * *
>
> (D) furnishing by transmission or distribution of natural or manufactured gas to the Alaska public for compensation;
>
> * * *

"Public" is defined by AS 42.05.701(5) as follows:

> "public" or "general public" means
>
> (A) any group of 10 or more customers that purchase the service or commodity furnished by a public utility as defined in (2) of this section; and
>
> (B) any utility purchasing the product or service or paying for the transmission of electric energy, natural or manufactured gas, or petroleum products which are resold to a group included in (A) of this paragraph or which are used to produce the service or commodity sold to the public by the utility.

If Phillips delivers royalty natural gas to the State at the wellhead, and the State contracts with Phillips for transportation of that gas to North Kenai Road, Phillips will be rendering a utility-type service because it will be engaged in the transmission of natural gas. Phillips, however, will be neither a "utility" nor "public utility" within the meaning of the Public Utilities statute because it will not be furnishing transmission service to the "public" or the "Alaska public." Phillips would be furnishing transmission service to the State. This would make it a public utility if 1) the State is the 10th customer to purchase transmission service (our assumption is there are less than 10 purchasers of transmission service), or 2)if the State is a "utility. . . paying for the transmission of. . . natural. . . gas. . . which is resold to [any group of 10 or more customers that purchase the service or commodity furnished by a public utility. . .]." The State would not be a utility (because it does not fit within the definition of AS 42.05.701(2)), thus Phillips could not be a public utility subject to the jurisdiction of the APUC when it furnishes transmission service to the State.

WLC:FHB:bvd

cc: Frederick H. Boness
Assistant Attorney General

Robert E. Stoller
Assistant Attorney General

PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA 74004 918 661-6500

NATURAL RESOURCES GROUP
Gas and Gas Liquids Division

March 3, 1977

Royalty Gas
North Cook Inlet Field

File: 1-Ho-115-77-G&GL

Mr. Donald G. Wold, Executive Director
Royalty Oil & Gas Development Advisory Board
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Dear Sir:

In your letter of February 25, 1977, you have requested certain information regarding whether Phillips could make the royalty gas from the North Cook Inlet Field available at an onshore location on the North Kenai Road, rather than in the field as provided in our lease with the State of Alaska. Information is listed by the numbers used in your letter:

2. Q. What charges would be made by Phillips for delivery of the gas to this point? What is the detailed justification of these charges?

   A. Since we had previously negotiated a place differential of 10¢ per Mcf starting with the calendar year of 1977 and increasing 6% per year thereafter with Alaska Pipeline Co., Phillips would be willing to utilize this approach with the State. Although this is a negotiated figure, the data supporting same is shown on Table I.

3. Q. We understand that as the field pressure declines, compressors will be installed to maintain production rate. What cost will be incurred by the State and what is the detailed justification of these costs?

   A. For the first compressor unit (approximately 3800hp) installed, compression charge would be 10¢ per Mcf increasing 6% per year from the year of installation. As later units are added, the compression charge will be agreed upon at that time. The above charge is the result of negotiations with Alaska Pipeline Company and is on the condition that Royalty gas would be handled only when there is surplus capacity in our gathering system and compressors. The above charge would be substantially higher if based on adding sufficient additional compressor capacity to assure the availability of capacity and would also entail a substantial minimum annual payment to cover these additional costs. Our calculations are attached as Table II.

4. Q. What is your best forecast of the dates of installation of the first and future compressors and how will the cost to the State change with installation of additional compressors?

4. Continued.

A. This is dependent on the amount of royalty gas taken by the State and also on other factors, such as, whether LNG in addition to current deliveries to Japan is sold to the south 48 states. Based on present information, we estimate that the first unit would be installed in 1978 or 1979.

5. Q. What is your best forecast of future production from this field? Will you share with the State your future production plans so that the State may plan accordingly to utilize its royalty gas?

A. Production has averaged 43 to 45 Bcf annually over the last several years. We visualize that production could increase to 55 Bcf or more per year including royalty gas taken in kind.

6. Q. The State understands your need to maintain production of your LNG plant and that your ability to deliver royalty gas to the State will change as the field pressure changes. Would you please explain this procedure and give us your best forecast of your ability to make delivery in the future?

A. Without compression, the volume available from North Cook Inlet Field will decline rather rapidly commencing in 1979. Producing at the 43 to 45 Bcf per year rate and with the installation of compressors, these rates are estimated to continue until 1986, after which the volume declines approximately 10% per year. If the higher rate of 55 Bcf per year is maintained, the volume will commence declining in 1984 at the rate of approximately 10% per year.

You will appreciate that, due to the number of unknown factors, the information provided above is based on our best estimates of the situation as it now exists. New developments could change these estimates.

John Horn

JH:jaw

cc: R. I. Swetnam

3-3-77
JH:jaw

TABLE I

PIPELINE

Estimated Present-Day Replacement Cost	at least	$25,000,000
Estimated Present-Day Replacement Cost Depreciated to 1977		17,300,000

ESTIMATED COSTS

	$/Year
Depreciation (20 Years)	$1,100,000
Rate of Return 15% on Depreciated Investment	1,520,000
Income Tax @ 52.9% (State & Federal)	1,700,000
Operating Expense	2,750,000
TOTAL	$7,070,000

Cost/Mcf @ 43 Bcf/Year = 16.4¢

Cost/Mcf @ 55 Bcf/Year = 12.9¢

TABLE I 7

COMPRESSORS
(FIRST UNIT)

To maintain capacity in the gathering system and compressors to handle the full 12.5% royalty gas volume, it will be necessary to install compressors at an earlier date. Also, it is estimated that to maintain this capacity it will be necessary to install an additional compressor unit over and above that required for maintaining deliveries without the State taking its royalty gas in kind. Estimated differential in compressor investment is $5,000,000.

Cost of Compression

	$/Year
Depreciation (10 Years)	$ 500,000
Rate of Return 15% on Average Investment	375,000
Income Taxes @ 52.9% (State & Federal)	420,000
Operating Expense	715,000
TOTAL	$2,010,000

Minimum Annual Payment	= $2,010,000
Royalty Gas Volume @ 43 Bcf/Year	= 5.4 Bcf
Royalty Gas Volume @ 55 Bcf/Year	= 6.9 Bcf
Cost/Mcf @ 5.4 Bcf	= 37.2¢
Cost/Mcf @ 6.9 Bcf	= 29.1¢

Phillips agreed with Alaska Pipeline Company's request to a compressor charge of 10¢/Mcf on a space-available basis and no minimum annual charge.

TABLE I

PIPELINE

Estimated Present-Day Replacement Cost	at least	$25,000,000
Estimated Present-Day Replacement Cost Depreciated to 1977		17,300,000

ESTIMATED COSTS

	$/Year
Depreciation (20 Years)	$1,100,000
Rate of Return 15% on Depreciated Investment	1,520,000
Income Tax @ 52.9% (State & Federal)	1,700,000
Operating Expense	2,750,000
TOTAL	$7,070,000

Cost/Mcf @ 43 Bcf/Year = 16.4¢ ✓ ≥ 10¢

Cost/Mcf @ 55 Bcf/Year = 12.9¢

TABLE II

COMPRESSORS
(FIRST UNIT)

To maintain capacity in the gathering system and compressors to handle the full 12.5% royalty gas volume, it will be necessary to install compressors at an earlier date. Also, it is estimated that to maintain this capacity it will be necessary to install an additional compressor unit over and above that required for maintaining deliveries without the State taking its royalty gas in kind. Estimated differential in compressor investment is $5,000,000.

What does this mean

Cost of Compression

	$/Year
Depreciation (10 Years)	$ 500,000
Rate of Return 15% on Average Investment	375,000
Income Taxes @ 52.9% (State & Federal)	420,000
Operating Expense	715,000
TOTAL	$2,010,000

Minimum Annual Payment	=	$2,010,000
Royalty Gas Volume @ 43 Bcf/Year	=	5.4 Bcf (12½%)
Royalty Gas Volume @ 55 Bcf/Year	=	6.9 Bcf (12½%)
Cost/Mcf @ 5.4 Bcf	=	37.2¢
Cost/Mcf @ 6.9 Bcf	=	29.1¢

Vs. 17¢

See Phillips 3/3/77 letter to Don Wold

from added compression

Phillips agreed with Alaska Pipeline Company's request to a compressor charge of 10¢/Mcf on a space-available basis and no minimum annual charge.

What does this mean? Does it mean APC would have to pay 10¢/Mcf only and would get royalty gas only when [illegible] [illegible] off? yes This would not make sense since 1/8 of production [illegible]

AGO 801638

PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA 74004 918 661-6500

NATURAL RESOURCES GROUP
Gas and Gas Liquids Division

March 3, 1977

Royalty Gas
North Cook Inlet Field

File: 1-Ho-115-77-G&GL

Mr. Donald G. Wold, Executive Director
Royalty Oil & Gas Development Advisory Board
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Dear Sir:

In your letter of February 25, 1977, you have requested certain information regarding whether Phillips could make the royalty gas from the North Cook Inlet Field available at an onshore location on the North Kenai Road, rather than in the field as provided in our lease with the State of Alaska. Information is listed by the numbers used in your letter:

2. Q. What charges would be made by Phillips for delivery of the gas to this point? What is the detailed justification of these charges?

   A. Since we had previously negotiated a place differential of 10¢ per Mcf starting with the calendar year of 1977 and increasing 6% per year thereafter with Alaska Pipeline Co., Phillips would be willing to utilize this approach with the State. Although this is a negotiated figure, the data supporting same is shown on Table I.

3. Q. We understand that as the field pressure declines, compressors will be installed to maintain production rate. What cost will be incurred by the State and what is the detailed justification of these costs?

   A. For the first compressor unit (approximately 3800hp) installed, compression charge would be 10¢ per Mcf increasing 6% per year from the year of installation. As later units are added, the compression charge will be agreed upon at that time. The above charge is the result of negotiations with Alaska Pipeline Company and is on the condition that Royalty gas would be handled only when there is surplus capacity in our gathering system and compressors. The above charge would be substantially higher if based on adding sufficient additional compressor capacity to assure the availability of capacity and would also entail a substantial minimum annual payment to cover these additional costs. Our calculations are attached as Table II.

4. Q. What is your best forecast of the dates of installation of the first and future compressors and how will the cost to the State change with installation of additional compressors?

4. Continued.

A. This is dependent on the amount of royalty gas taken by the State and also on other factors, such as, whether LNG in addition to current deliveries to Japan is sold to the south 48 states. Based on present information, we estimate that the first unit would be installed in 1978 or 1979.

5. Q. What is your best forecast of future production from this field? Will you share with the State your future production plans so that the State may plan accordingly to utilize its royalty gas?

A. Production has averaged 43 to 45 Bcf annually over the last several years. We visualize that production could increase to 55 Bcf or more per year including royalty gas taken in kind.

6. Q. The State understands your need to maintain production of your LNG plant and that your ability to deliver royalty gas to the State will change as the field pressure changes. Would you please explain this procedure and give us your best forecast of your ability to make delivery in the future?

A. Without compression, the volume available from North Cook Inlet Field will decline rather rapidly commencing in 1979. Producing at the 43 to 45 Bcf per year rate and with the installation of compressors, these rates are estimated to continue until 1986, after which the volume declines approximately 10% per year. If the higher rate of 55 Bcf per year is maintained, the volume will commence declining in 1984 at the rate of approximately 10% per year.

You will appreciate that, due to the number of unknown factors, the information provided above is based on our best estimates of the situation as it now exists. New developments could change these estimates.

John Horn

JH:jaw

cc: R. I. Swetnam

3-3-77
JH:jaw

TABLE I

PIPELINE

Estimated Present-Day Replacement Cost .....at least $25,000,000

Estimated Present-Day Replacement Cost Depreciated to 1977 17,300,000

ESTIMATED COSTS

	$/Year
Depreciation (20 Years)	$1,100,000
Rate of Return 15% on Depreciated Investment	1,520,000
Income Tax @ 52.9% (State & Federal)	1,700,000
Operating Expense	2,750,000
TOTAL	$7,070,000

Cost/Mcf @ 43 Bcf/Year = 16.4¢

Cost/Mcf @ 55 Bcf/Year = 12.9¢

JH: jaw

TABLE II

COMPRESSORS
(FIRST UNIT)

To maintain capacity in the gathering system and compressors to handle the full 12.5% royalty gas volume, it will be necessary to install compressors at an earlier date. Also, it is estimated that to maintain this capacity it will be necessary to install an additional compressor unit over and above that required for maintaining deliveries without the State taking its royalty gas in kind. Estimated differential in compressor investment is $5,000,000.

Cost of Compression

	$/Year
Depreciation (10 Years)	$ 500,000
Rate of Return 15% on Average Investment	375,000
Income Taxes @ 52.9% (State & Federal)	420,000
Operating Expense	715,000
TOTAL	$2,010,000

Minimum Annual Payment	= $2,010,000
Royalty Gas Volume @ 43 Bcf/Year	= 5.4 Bcf
Royalty Gas Volume @ 55 Bcf/Year	= 6.9 Bcf
Cost/Mcf @ 5.4 Bcf	= 37.2¢
Cost/Mcf @ 6.9 Bcf	= 29.1¢

Phillips agreed with Alaska Pipeline Company's request to a compressor charge of 10¢/Mcf on a space-available basis and no minimum annual charge.

Phillips

See March 3, 1977 reply

February 25, 1977

Mr. John Horn
Phillips Petroleum Company
Gas and Gas Liquids Division
Bartlesville, Oklahoma 74004

Dear Mr. Horn:

As you know, the State of Alaska entered into an agreement with the Alaska Pipeline Company on June 4, 1976 for the sale of the State's royalty gas produced from your company's North Cook Inlet Gas Field. The Alaska Pipeline Company and Phillips have been unable to work out a mutually satisfactory arrangement for delivery of the gas. The State of Alaska, through the Department of Natural Resources, is continuing to explore various ways this can be accomplished in the interest of all parties.

The Alaska Pipeline Company has proposed that the State enter into an agreement with your company to take delivery of royalty gas from your pipeline at a mutually agreeable point near the North Kenai Road. The State is presently exploring this possibility and your cooperation has been greatly appreciated. Several questions have been raised regarding this procedure. They are:

1. Will the Alaska Public Utilities Commission have jurisdiction over the Phillips pipeline if the State takes delivery at this point? The State's Attorney General has been asked for an opinion.

2. What charges would be made by Phillips for delivery of the gas to this point? What is the detailed justification of these charges?

3. We understand that as the field pressure declines, compressors will be installed to maintain production rate. What costs will be incurred by the State and what is the detailed justification of these costs?

4. What is your best forecast of the dates of installation of the first and future compressors and how will the cost to the State change with installation of additional compressors?

AGO 801643

PHILLIPS WILL DEFINITELY INCUR ADDITIONAL COSTS IF

5. What is your best forecast of future production from this field? Will you share with the State your future production plans so that the State may plan accordingly to utilize its royalty gas?

6. The State understands your need to maintain production of your LNG plant and that your ability to deliver royalty gas to the State will change as the field pressure changes. Would you please explain this procedure and give us your best forecast of your ability to make delivery in the future.

Your response to the above would be greatly appreciated together with any further information that you may feel to be pertinent to the solution of this problem.

Would you please review the draft agreement prepared by Alaska Pipeline Company between Phillips and the State and recommend changes that may be of interest to your company?

Thank you for your cooperation. Your early response to the above will be greatly appreciated.

Very truly yours,

Donald G. Wold
Executive Director

DGW/jl

DEPARTMENT OF NATURAL RESOURCES
OFFICE OF THE COMMISSIONER

Readers
cc: FB
cc: Roy Bd 225

TO: Avrum Gross
Attorney General

DATE : February 24, 1977

FROM: Guy Martin
Commissioner

SUBJECT: Alaska Pipeline Company - Gas Purchase Contract 76-1.

As you know, the State of Alaska entered into an agreement with the Alaska Pipeline Company on June 4, 1976 for the sale of the State's royalty gas being produced in the "upper Cook Inlet area" by Phillips Petroleum on the North Cook Inlet platform.

Paragraph 3.1 of this agreement provides "The point of delivery of all gas delivered hereunder shall be at the same point of delivery that Seller receives delivery of its royalty gas from its lessee in the North Cook Inlet Field". The producer, Phillips, was to make delivery, in accordance with the lease agreement, at the wellhead. Paragraph 3.2 of this agreement, states "Buyer, at its own expense, shall arrange to accept Sellers gas at the point of delivery". This point is, of course, offshore on the Phillips platform.

Phillips presently operates their own pipeline from the platform to transport the gas to their LNG plant located near the North Kenai Road. It is the responsibility of the Alaska Pipeline Company to work out an arrangement with Phillips to have the royalty gas transported to an agreeable point where they can take possession.

The Alaska Pipeline Company and Phillips were able to work out an agreement for Phillips to deliver the gas at a point near the terminus of the pipeline (see enclosed map) located near the North Kenai Road. However, to do so, Phillips would become subject to the jurisdiction of the Alaska Public Utilities Commission, which they refuse to do. Attempts have been made by Alaska Pipeline Company to obtain an exemption of jurisdiction for Phillips from the APUC. However, Phillips alone must obtain the exemption and to do so they must submit to the jurisdiction of the APUC. If this problem is not resolved, the State will be unable to take this gas in-kind to complete the sale.

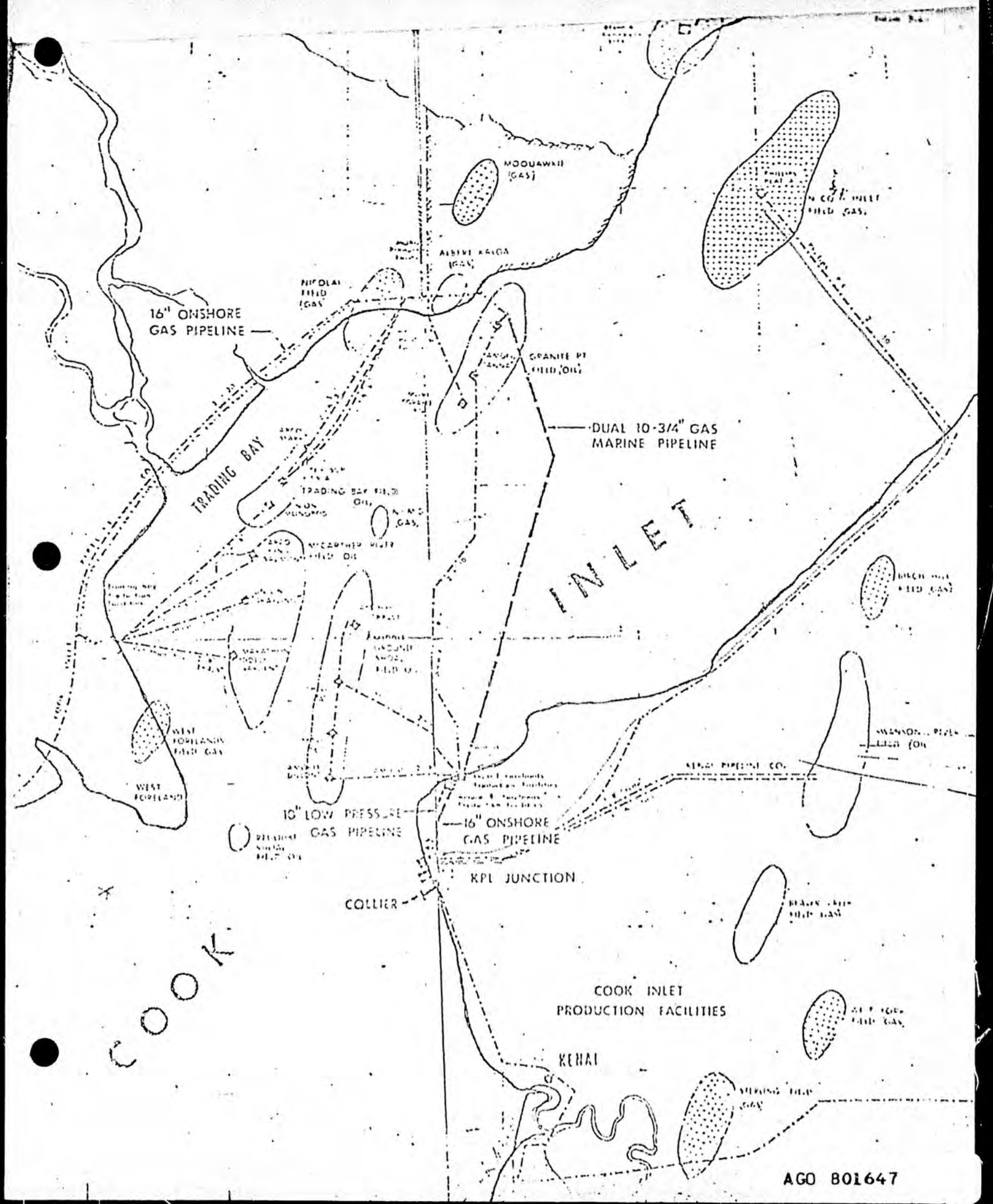
The Alaska Pipeline Company has now proposed that the State accept delivery near the terminus of the Phillips pipeline located near the North Kenai Road and then deliver the gas at this point to the Alaska Pipeline Company. APC would pay any costs incurred in such a delivery.

It is presently believed that Phillips would be willing to enter into such an arrangement if the Attorney General renders a written opinion that delivery of the gas under this arrangement will not subject them (Phillips) to the jurisdiction of the APUC.

We would sincerely appreciate your review and opinion of this matter. Should you need any assistance or further information please do not hesitate to call upon us. We hope to bring a report and recommendation to the Royalty Oil and Gas Development Advisory Board on March 8, 1977.

cc: Don Wold
Fred Boness

GRM/DGW/jl


16" ONSHORE
GAS PIPELINE
DUAL 10-3/4" GAS
MARINE PIPELINE
TRADING BAY
INLET
10" LOW PRESSURE
GAS PIPELINE
16" ONSHORE
GAS PIPELINE
KPL JUNCTION
COLLIER
COOK INLET
PRODUCTION FACILITIES
KENAI
COOK
AGO 801647

ALASKA PIPELINE COMPANY

P. O. BOX 6554 • HOUSTON, TEXAS 77005

February 23, 1977

Commissioner Guy Martin
Department of Natural Resources
State of Alaska
Juneau, Alaska

Dear Mr. Martin:

My understanding of the Royalty Board's action of February 22 was that you would inquire of the Attorney General as to the propriety of the State's contracting to deliver North Cook Inlet royalty gas to us onshore, at the delivery charges we have negotiated with Phillips, while warranting to Phillips that their delivery to us for the account of the State (which we would underwrite and pay) would not result in regulatory jurisdiction by the Alaska Public Utilities Commission or the Alaska Pipeline Commission over Phillips.

We met with the Attorney General also on February 22 to apprise him of the matter at hand, but for only a very few minutes and without a full discussion. We are of course hopeful that all essential concurrences will be available, whether as a legal opinion or as an approval of the contracts for the proposed action. We do need to pursue this subject urgently in order to have an amended contract approved in the present legislative session and begin taking the royalty gas as soon as possible this year.

We appreciate your courtesy to us at the February 22 meeting and we hope to appear if necessary at the next meeting to answer any further questions. Meanwhile, except as to our paying Phillips for the account of the State, our previous drafts of proposed contract language would apply to the course we hope the State will follow.

Very truly yours,

Dale Teel
President

DT:t

cc: Mr. Don Wold, Executive Director
Oil and Gas Royalty Advisory Board
State of Alaska
Juneau, Alaska

Mr. Avrum Gross, Attorney General
State of Alaska
Juneau, Alaska

Mr. John Horn
Phillips Petroleum Company
Bartlesville, Oklahoma

Mr. Gordon Zerbetz, Chairman
Alaska Public Utilities Commission
11th Floor, MacKay Building
Anchorage, Alaska

AGO 801648

from Dalthell

No logged or copied
2-23-77

Possible approach regarding transportation and compression charges:

The Lessor (State) and the Lessee (Phillips) would have an agreement under which the Lessee will give the Lessor its royalty share of the gas at a point convenient to the Lessor. The Lessor will bear the costs associated with making the royalty share of the gas available to it. That agreement will provide that the State's obligation will be discharged by payment of those costs by APC and Phillips will agree that such a payment will satisfy the State's obligation.

In the Agreement between APC and theState, APC will covenant and undertake to discharge (or underwrite) the State's obligation to the State's Lessee by making payment of the transportation and costs directly to the State's Lessee.

RECEIVED
FEB 23 1977
ALASKA ROYALTY
OIL & GAS BOARD

State & Phillips agree on 11 Road Delivery Point

—— Royalty line is built

—— State contract is changed

(a) article III regards delivery points

(b) APC take or pay for all that can be delivered, forfeit the rest *

(c) APC reimburse State for dehydration & delivery charges paid to Phillips

* that's not a "take or pay" provision

1. We take or pay for all royalty gas delivered to the plant. Phillips pay $ royalty on undelivered portion (to State).

?

2. Phillips transport all of the "9/8" or as much as possible of this to the LNG plant. State pays Phillips for –

(a) dehydration

(b) gathering

(c) compression

3. We pay the state for the [illegible] for gas delivered plus the royalty price with the total as our cost of gas. The State is whole

4. If there is [illegible] royalty

7 (a) we flow the excess [illegible] APC [illegible]

1. [illegible]

2. [illegible]

(b) [illegible]

5. If there [illegible] royalty [illegible]

[illegible]

(b) [illegible]

[illegible]

[illegible]

AGO 801650

6. Advantages APC

(a) may gain (conserve) some reserves
(b) take or pay liability is reduced
(c) deal with only Phillips & State
(d) no premium $ for standby gas
(e) no exchange prices
(f) all inclusive cost of gas
(g) the several future benefits of the royalty line
(h) the royalty line would provide a source of gas to cover in event future rules change

Disadvantages to APC

(a) take or pay considerations
(b) may have to take make up gas out of 100 million acres
(c) have to make major capital investments.

7. Advantages to State

(a) get more royalty $ on same volumes
(b) get advanced royalty if excess balance
(c) other more $ features due to repairs, farmed [illegible]

Disadvantages to State

(a) could lose [illegible]
[illegible] $ royalty on "[illegible]" [illegible]

AGO 801651

8 Advantages to Bullys

(a) are in a no burden situation.

(b) get some benefit as a major power user

(c) receive add'l $ for add'l throughput to apply against hardware

(d) would "recover" reserves in amount of "non-delivered" royalty.

(e) may be free of APUC feature

Disadvantages

(a) may feel pressure to deliver

(b) shortened reserve life.

AGO 801652

APC notes

State + Phillips agree on N. Road delivery point
No royalty line is built
State contract is changed
(a) article III regards delivery point
(b) APC to take or pay for all that can be delivered
(c) APC to reimburse state for dehydration + delivery charges paid to Phillips

Where is this reflected?

1. We take or pay for all royalty gas delivered to the plant. Phillips pays royalty in $ for "undelivered" portion

?

2. Phillips transport all of "9/8" or as much as possible of it into the LNG plant. State pays Phillips for-
   dehydration
   gathering
   compression

3. We reimburse state for these same charges as part of our cost of gas. The state is "whole".

Exchange?

4. Marathon reduce their plants feed share by a volume equal to the delivered royalty. The plant feed is "whole"

5. We take what we can sell [up to the delivered royalty volume] from Marathon through existing ~~facilities~~ facilities.

6. If there is too much royalty
   (a) we flow the excess to Anchorage via the Kenai field [Marathon share]
   (b) or we bank the excess in the Kenai field as owned gas what we do could depend on take or pay treatment

AGO 801653

7. If there is not enough royalty produced
   (a) Phillips produces additional gas for our account & delivers it ok
   (b) or we take from Marathon out of our owned Kenai "banked" gas
   (c) or we take from Union/Marathon out of our ~~excess~~ regular Kenai reserves

8 If there is not enough royalty delivered
   (a) same as #7 except (a) option would be unavailable
   (b) Phillips pay 8 royalty ~~in lieu of~~ on undelivered royalty share

9. Advantages to APC/state payer

how is that? (a) "gain" additional reserves at current prices

Other than what you would have to pay Phillips → (b) no additional purchases & associated costs

✓ (c) dehydration, transportation & compression are included in cost of gas

how? (d) take or pay liability is reduced

? How (e) have one owned gas in N. Cook with future decline problem

? How (f) cleaner APUC situation on waiver

(g) good flexibility

Disadvantages

   (a) some take or pay liability with state

How? (b) may get into take or pay with Union/Marathon

✓ (c) APC cost of gas goes up

   (d) tax question on gas paid for but not taken

✓ (e) have these "reserves" (royalty) forfeited to Phillips

10. Advantages to the State

how? (a) get more royalty $ on same quantity of gas

That's not really true! gas not used by APC would go to Phillips (b) would get "advance" royalty on "banked" gas

(c) may realize more $ on N Cook due to favored nations

how? (d) residents get benefit of gas usage

They have prior to that time — so what else is new?

Disadvantages

(a) some administration effort required due to State/Phillips contract.

11 Advantages to Phillips

What is "lost"? (a) are able to utilize some of the "lost" royalty in their plant

What does that mean? (b) provide royalty on no burden basis

What's so grand about it? What exactly is meant here? (c) would receive add'l $ for add'l throughput of existing + future facilities.

how? would it not be accelerated (d) field depletion rate would slowed a bit

Disadvantages

✓ (a) may feel pressure to deliver royalty

✓ (b) APUC question may still exist

How? see (d) above (c) shortened plant reserve life.

AGO 801655

12 Advantages to Marathon

? (a) would get add'l $ for Kenai gas used as standby gas

? (b) would get add'l $ for exchange service

? (c) if gas is bank in or exchanged for Kenai gas it will result in more gas to reprice in 1986

Disadvantages

? (a) could have deferred sales on Anchorage contract

13 Required

(a) State/Phillips contract for dehydration, transport & compression

What's that? (b) balancing agreement with Phillips

(c) State contract change

What's that? (d) balancing, exchange, standby agreement with Marathon

(e) APUC question

(f) pre-determination of take or pay treatment for rate making

" "cost of gas"

Yes!!!

AGO 801656

STATE of ALASKA

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES
OFFICE OF THE COMMISSONER

J-Ak Pipeline
Readers
cc: Board

TO: Guy Martin
Commissioner

DATE : February 14, 1977

FROM: Don Wold

SUBJECT: Alaska Pipeline Company-
Gas Purchase contract 76-1

Alaska Pipeline Company has been unable to work out an arrangement with Phillips Petroleum Company to take delivery of the State Royalty gas contracted on June 4, 1976 between the State and subject company. There are two reasons why Alaska Pipeline Company has been unable to solve this problem. They are:

1. In accordance with the contract, buyer is to purchase all royalty gas to be used to meet the requirements of its customers within the State of Alaska. (They do not have customers to consume all of this gas all of the time. Phillips has agreed to take back any surplus at their purchase price, however, this violates the contract. Homer Electric is the primary customer and cannot consume all the gas available.)

2. Alaska Pipeline Company must take delivery from Phillips near the terminus of the Phillips pipeline located near the North Kenai Road. To do so, Phillips would be subject to the jurisdiction of the Alaska Public Utilities Commission, which they refuse to do. Phillips alone must obtain an exemption of jurisdiction for their pipeline from the APUC and to do so they must submit to jurisdiction by the APUC. One major purpose of the APUC is to consider the cost of such gas transmission and the cost of compression which would be passed on to the Alaska Pipeline Company and to the consumer by Phillips to accommodate delivery.

There is one further serious consideration relating to this contract. If the State does not cooperate in resolving this problem, the Alaska Pipeline Company will have control of this gas until 1984 whether or not they ever take delivery. This assumes that they will retain their rights under the contract. This means that Phillips will be able to take all royalty gas for their use and the State will be unable to use it for any other purposes or to deliver it to anyone else who could work out an arrangement to accept delivery.

Alaska Pipeline Company has now proposed that the State accept delivery near the terminus of the Phillips Petroleum Company pipeline located on the North Kenai road and then deliver

the gas at this point to Alaska Pipeline Company. To this end Alaska Pipeline Company had drafted two agreements. One agreement is a new gas purchase contract between Alaska Pipeline Company and the State of Alaska to replace the one previously entered into and another between the State and Phillips Petroleum Company for the taking of the royalty gas in-kind at the new delivery point. These agreements and the forwarding memo are appended.

The Alaska Pipeline Company, Phillips Petroleum Company and myself met in Bartlesville, Oklahoma to attempt to work out an arrangement whereby Phillips could cooperate. Attending this meeting were: Don Wold, John Horn, Phillips Petroleum Company, John L. Williford, Phillips Petroleum Company attorney, C. J. Silas, Vice President, Phillips Natural Gas Department and Dale Teel, President of Alaska Pipeline Company. Phillips has reviewed the enclosed agreements and are concerned about whether or not the taking of the gas at the North Kenai road will, in fact, exempt them from the jurisdiction of the Alaska Public Utilities Commission. They are not satisfied that by simply delivering the gas to a different party satisfies the problem of the APUC. Phillips will consider accepting such an agreement if the Attorney General renders an opinion that Phillips will not come under the jurisdiction of the APUC. Alaska Pipeline Company has retained the services of former Commissioner Tony Motley to assist them in bringing the issue to the attention of the Attorney General and to encourage an opinion. Should this effort be successful it seems that the Department of Natural Resources will in fact assume a portion of the responsibilities of the APUC in determining whether or not the pipeline tariff and compression charges are in the interest of the State.

The APUC would normally audit, in some detail, the delivery charges and the compression cost that would be passed on to the consumer. This situation has certain obvious political concerns that must be considered.

In accordance with the proposed agreement, the Alaska Pipeline Company must agree to accept the charges identified by the State's and Phillips Petroleum Company's agreement, and the APUC must concur since they have rate setting authority. It should be noted that the APUC has an apparent agreement with Alaska Pipeline Company to fold-in all royalty gas costs to their rate base and do not have to justify such increased costs to the APUC. Therefore, Alaska Pipeline Company does not need to justify these higher costs. All they must do is fold-in the costs and pass them through to the consumer. This is being confirmed by the PUC.

Phillips will agree to the above, subject to the approval of their management. They have, however, asked why they should cooperate since they must go to considerable expense with no return and stand a chance of obtaining adverse publicity by having to appear before the Royalty Board and the Legislature to respond to questioning regarding the agreements. The State has the responsibility to acquire royalty gas for use wihtin the State if needed and they would stand a potential of obtaining even greater adverse publicity should they refuse to cooperate and prevent the State from using such needed gas. gas.

Phillips has agreed to supply the State with complete justification of the transportation costs and compression costs. They will also supply a forecast of future production. They will also explain how production will decline and how the production's change will affect the deliverablity to the State. They will also supply a detailed forecast of the installation of the compressors. They will also determine whether or not they could agree to the State's involvement in determining when the installation of the compressors is necessary.

The Alaska Pipeline Company desires to appear before the Royalty Board at an early date to explain their case and urgently request that this be considered at this session of the Legislature. Should they need to wait until next year, the term of the contract will be so short as to make it not worthwhile.

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 Anchorage, Alaska 99502 / Phone (907) 277-5551
Telex 25-187

February 2, 1977

Mr. Donald Wold, Executive Director
Oil and Gas Royalty Advisory Board
Department of Natural Resources
Juneau, Alaska 99801

Dear Mr. Wold:

Following our conversation January 31 in your office, we have proceeded to write a re-draft (enclosed) of the contract executed June 4, 1976, to provide for the delivery of North Cook Inlet royalty gas to us by the State, near the Kenai LNG plant. This restructuring may be desirable and necessary to reflect the pricing, delivery conditions, start of deliveries, and non-jurisdictional aspects of the transaction which might otherwise cause serious problems with the existing contract.

It is our hope that this draft will be sufficient to describe the entire operation adequately so that it can be used as an attachment to and part of a State developed agreement to take delivery of the royalty gas from the Lessee (Phillips Petroleum Company) at the same onshore point and minimize the drafting of a detailed separate agreement with the Lessee. A suggested draft of a "notice" and "acceptance" letter for possible use with the Lessee is also enclosed.

There are several substantive changes in the proposed contract draft, none of which result in greater liability or less revenue to the State. In addition to reflecting the higher royalty price as of January 1, 1977, and preserving all prior price escalations, we would agree to pay the appropriate (proportionate) share of compression which the Lessee may install at a future date (after the initial unit). However, we would commit to purchase only the royalty gas we can readily re-sell (up to 100% of what is available) and thus not be committed to install a pipeline connecting to our existing pipeline to Anchorage, although we could do so at our option. The availability and cost of "stand-by gas" from our present suppliers may have to be determined before we can reach that decision. We are of course concerned about the short life remaining (only 6 years - to July 1984) to pay out a multi-million dollar pipeline. If the State could now amend the

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 / Anchorage, Alaska 99502

term of this contract to the "life of production", which we proposed originally, the feasibility of such a pipeline would be much improved.

There are several non-substantive additions in the proposed contract draft, copied largely from the contract draft we had negotiated with the Lessee. The provisions for the most part are technical and standard for the industry and we are not aware of any reason for controversy. In the proposed contract treatment there would be no contractual relationship between us and the Lessee, and thus these provisions appear to be necessary as part of our contract with the State.

We have forwarded copies of these drafts to the Lessee and hope to have their response in time to plan to attend the meeting of the Royalty Advisory Board on February 22. We must be in Houston on the morning of February 23 for our annual Board meeting and would ask to be scheduled as early on your agenda as possible.

Very truly yours,

Dale Teel
President

DT:dh

Enclosures

cc: John Horn-Phillips-Bartlesville
Bob Swetnam-Phillips-Anchorage

Proposed Notice
By the State of Alaska
To Phillips Petroleum Company
For the Taking of Royalty Gas in Kind
From the North Cook Inlet Gas Field

Gentlemen:

The State of Alaska hereby notifies you that upon the completion of installation of the necessary physical facilities on shore by Alaska Pipeline Company, and their notice to you and to the State to that effect (which will be prior to May 1, 1978), the State of Alaska will elect to receive its royalty interest in gas produced from the North Cook Inlet Gas Field in kind to the extent of Alaska Pipeline Company's taking of said royalty gas. It is not anticipated that Alaska Pipeline Company will take 100% of the royalty gas each day or each month, and thus there will continue to be royalty payable in cash to the State to the extent of royalty gas not taken in kind.

The point of delivery of the royalty gas is to be at a mutually acceptable point onshore (in the vicinity of your Kenai LNG plant). Measurement and control of the royalty gas taken in kind will be the responsibility of Alaska Pipeline Company. You may deduct, from the amount of royalty payment otherwise due the State, the charge(s) described on page(s) 7-9 of the State's contract with Alaska Pipeline Company as consideration for the dehydration and gathering including compression of the royalty gas which you will provide to the State. These charges were negotiated by you and are acceptable to the State and to Alaska Pipeline Company, as described in the contract, copy of which is attached hereto as information and for purposes of implementing this notice to you.

This notice and the attached copy of the State's contract with Alaska Pipeline Company are confirmation to you that your cooperation in agreeing to deliver royalty gas onshore at the charge(s) described and at the request of the State does not subject you to the jurisdiction of the Alaska Public Utilities Commission or the Alaska Pipeline Commission, nor does it affect the price payable by you for royalty gas you continue to take for processing.

It is understood and acknowledged by the State that the primary purpose of your operations is to meet your own contractual and other business obligations and that the delivery of royalty gas onshore is of secondary importance and is subordinate to your primary obligations.

Please acknowledge your acceptance of this Notice, and the terms and conditions as described herewith, in the space provided below and return two executed copies to us.

Accepted for Phillips Petroleum Company:

By _____ Date _____

For the State of Alaska:

By _____ Its _____

GAS PURCHASE CONTRACT

This Contract, made and entered into this day of 1977, by and between the Alaska Pipeline Company ("APC") herein referred to as "Buyer" and the State of Alaska, hereinafter referred to as "Seller":

WITNESSETH

WHEREAS, Buyer owns and operates a natural gas pipeline system in areas of Alaska for the delivery of natural gas for ultimate consumption within the State of Alaska, and

WHEREAS, Seller has the right under each of the leases identified at Exhibit "A" attached hereto to be paid by the Lessee thereunder a royalty of twelve and one-half percent in kind or in value of the natural gas produced and saved and used off of the lands covered by each such lease, and

WHEREAS, Seller is authorized by AS 38.05.183 to sell royalty gas; and

WHEREAS, Buyer represents to Seller that the gas received by Buyer under this contract will be used to meet the requirements of its customers within the State of Alaska;

NOW, THEREFORE, in consideration of the representations, convenants, and conditions herein contained, Buyer and Seller hereby agree as follows:

ARTICLE 1

Seller's Royalty Gas

1.1 Seller hereby agrees that within 30 days after the execution and approval of this agreement as required by the laws of the State of Alaska, Seller shall notify the Lessee under the leases set forth at Exhibit "A" of this agreement of Seller's election to take its royalty gas in kind. Said notice will provide that the Lessee shall commence the delivery of said royalty gas to Seller (or to Seller's designee) upon a receipt of notice from Seller that all facilities necessary to enable Buyer to receive and market said gas are ready; provided, however, in no event shall Lessee be required to commence the delivery of royalty gas to Seller (or its designee) prior to six (6) months following Lessee's receipt of notice of Seller's election to take its royalty gas in kind.

1.2 In order that Seller can give its Lessee as much advance notice as possible of the date it will start receiving its royalty gas in kind, Buyer shall notify Seller, and Seller shall notify its Lessee, at least 60 days prior to the date Buyer will receive gas from Seller pursuant to this contract.

ARTICLE II

Quantity

2.1 It is understood and agreed by the parties that the volume of gas available to Seller from the leases covered by this contract depends upon the production from the leases over which Seller has no control, and further depends upon the Lessee's gathering capacity installed and available, over which Seller likewise has no control.

Buyer hereby agrees to purchase on each day commencing with the date of first delivery hereunder and continuing during the term of this contract up to all of Seller's royalty gas available at the point of delivery described in Article IV hereof, it being understood that Buyer's requirements for its markets may not allow Buyer to purchase the entire amount of Seller's royalty gas on each day it is available.

ARTICLE III

Quality, Pressure, and Odorization

3.1 The gas to be delivered by Seller to Buyer at the delivery point shall be gas of the same quality and pressure as delivered to Seller by the Lessee at the point of delivery.

3.2 Gas delivered hereunder will not be odorized and if Buyer so utilizes the gas delivered hereunder for purposes which require odorization of such gas, the full responsibility for such use is Buyer's and Buyer agrees to comply with all laws and regulations respecting the odorization of such gas and hereby indemnifies and holds Seller harmless from any and all claims, injuries, expenses, penalties and damages arising out of or connected with Buyer's failure to observe strictly and comply with all laws, rules and regulations with respect hereto.

ARTICLE IV

Point of Delivery, Point of Measurement, Ownership, and Measurement

4.1 Buyer shall install, maintain, and operate a connection into the Lessee's pipeline system at or near Lessee's pipeline tap which

delivers gas to the Tesoro refinery located in the general vicinity of the Kenai LNG plant on the North Kenai Road, (hereinafter called "the point of delivery").

4.2 Buyer agrees to install, maintain, and operate all pipeline, pressure regulators, and related facilities necessary to receive gas hereunder at and from the point of delivery above specified, to Buyer's existing metering station also located in the general vicinity of the Kenai LNG plant on the North Kenai Road (hereinafter called "the point of measurement").

4.3 Buyer shall be deemed to be in control and possession of the gas delivered hereunder at and from the point of delivery and responsible for any damage or injury caused thereby. Buyer shall be responsible for any gas lost between the point of delivery and the point of measurement. Buyer shall indemnify and hold Seller harmless as to any injury or damage arising out of the delivery of gas to Buyer and its measurement hereunder.

4.4 Standards of Measurements and Tests

4.4.1 The unit of volume of gas delivered hereunder shall be one (1) cubic foot at an absolute pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch and at a base temperature of sixty (60) degrees Fahrenheit.

4.4.2 The volumes of gas delivered hereunder shall be measured and computed by Buyer in accordance with the methods prescribed in Gas Measurement Committee Report No. 3, Natural Gas Department, American Gas Association, including the Appendix thereto, dated April, 1955, except that the atmospheric pressure shall be assumed to be fourteen and seven-tenths (14.7) pounds per square inch. The method used for

correcting such volumes for deviation from the Ideal Gas Laws shall be the procedure recommended in the most current Report of the American Gas Association or by any other method mutually agreeable to the parties hereto.

4.4.3 The specific gravity of the gas delivered hereunder shall be determined by Lessee utilizing the method prescribed in American Petroleum Institute Code No. 50-A at the beginning of delivery hereunder and once during each month thereafter. The results of each such determination shall be used in computing the volume of gas delivered hereunder until the effective date of the next succeeding test.

4.4.4 The flowing temperature of the gas delivered hereunder shall be determined by means of a continuous recording thermometer installed by Buyer so that it will properly record the temperature of the gas flowing through the meter. The arithmetical average of the hourly temperatures recorded each day shall be used in computing the volumes of gas delivered during such day.

4.5 Measurement

4.5.1 The Lessee may, at its option and expense, install check meters upstream or downstream of Buyer's meter station provided that such check meters will be installed so as not to interfere with the operation of Buyer's facilities. The calibrating and adjusting of Lessee's meters and the changing of charts and the reading of charts on Lessee's meters shall be done by Lessee.

4.5.2 Buyer and Lessee shall have access at all times to Buyer's metering equipment including all other instruments used by

Buyer in determining the measurement and quality of the gas delivered hereunder, but the reading, calibrating and adjusting thereof, and the changing of charts shall be done only by the employees, agents, or representatives of Buyer. Upon request of Lessee, Buyer shall submit to Lessee records and charts from such equipment subject to return by Lessee within thirty (30) days after receipt thereof.

4.5.3 At least once a month Buyer shall test its above mentioned metering equipment or cause the same to be tested and Buyer shall give Lessee reasonable prior notice of the time all such tests are to be made so that Lessee may, if desired, have its representative present to observe such tests and any adjustments made upon such metering equipment. Following any test, any of Buyer's metering equipment found to be inaccurate to any degree shall be adjusted immediately to measure accurately. If upon any test such metering equipment is found to be inaccurate by two percent (2%) or more, registration from said metering equipment and any payments based upon such registrations shall be corrected at the rate of such inaccuracy for any period of inaccuracy which is definitely known or agreed upon, but in case the period is not definitely known or agreed upon, then for a period extending back one-half of the time elapsed since the last previous test, not exceeding however fifteen (15) days.

4.5.4 If for any reason Buyer's meter is out of service or is found registering inaccurately and the error is not determinable by ordinary test such that the volume of gas delivered through such meter cannot be ascertained or computed from the readings thereof, the volume of gas so delivered during the period the meter is out of service or registering inaccurately shall be estimated and agreed upon by the

parties hereto upon the basis of the best available data, using the first of the following methods which is feasible:

(a) By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation;

(b) By using the registration of any check measuring equipment of Lessee if installed and registering accurately;

(c) By estimating the volume by comparing it with deliveries during preceding periods under similar conditions when the meter was registering accurately.

ARTICLE V

Price and Billing

5.1 The price to be paid by Buyer to Seller for gas deliveries shall be as follows:

(a) Commencing on the date of first deliveries hereunder Assuming that this date occurs prior to July 1, 1978 and continuing until the first day of July, 1978, the price shall be 64.65 cents per MCF. vs. 60.36 mention in contract 76-1 of 6/4/76

(b) Commencing on the first day of July, 1978 and continuing until the first day of July, 1979 the price shall be the higher of (i) 66.65 cents per MCF, (ii) the price Seller would have received from Lessee had it not elected to receive its royalty gas in kind, (iii) the highest price paid by

any purchaser in the upper Cook Inlet area for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges.

(c) For each succeeding 12 month period commencing July 1, 1979 the price shall be increased to the higher of (i) the previous year's price plus 2 cents per MCF, (ii) the price Seller would have received had it not elected to take its royalty in kind, (iii) the highest price paid by any purchaser in the upper Cook Inlet area for gas of similar quality and conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges.

(d) To the price otherwise payable hereinabove, Buyer shall add the charge of 10¢ per MCF from the date of first deliveries hereunder until the date of the completion of the first unit of compression facilities (approximately 3500 hp), ready for use on Lessee's platform and after such date Buyer shall add the charge of 20¢ per MCF, in consideration of Seller's costs for gathering gas sold hereunder to the point of delivery. Each of the above charges shall increase by six percent (6%) per year, commencing upon the respective anniversary dates thereof.

In the event that further unit(s) of compression facilities may be required and are installed on Lessee's

platform, Buyer shall, after such date, add to the price and charges otherwise payable hereinabove a further charge, to be computed in the ratio of gas volumes delivered (the ratio of deliveries to Buyer compared to the Lessee's total deliveries) during the preceding year, a proportionate share of the Lessee's full cost of owning, maintaining, and operating such further unit(s) of compression, as reported by Lessee to Seller and subject to Seller's verification.

Nothing herein shall be construed as an obligation for Seller or Lessee to install or to operate any compression facilities, and all judgment with respect to such installation or operation shall be and remain solely with Lessee.

5.2 Thirty days prior to the date of each annual price change, Seller, at its option, may determine the price which it would have received from its Lessee had it not elected to take its royalty gas in kind and the highest price being paid for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges in the upper Cook Inlet area and submit the same to Buyer along with suitable supporting evidence as to such prices. Buyer shall have the right to submit other evidence within the 30 day period.

5.3 After the delivery of gas has commenced Buyer shall, on or before the 20th day following the end of each month, render to Seller and Lessee a statement showing the quantity of gas delivered during that month

and shall therewith pay Seller the amount due for all such gas.

5.4 Each party hereto shall have, at its expense, the right to examine the books and records of the other party to the extent necessary to verify the accuracy of any statement, charge, computation, or demand made under or pursuant to this contract. Any statement shall be final as to both parties unless questioned in writing within two (2) years after payment thereof has been made.

5.5 The terms "upper Cook Inlet area" as used here in shall mean the area encompassed in a radius of 100 kilometers from the Lessee's North Cook Inlet platform.

ARTICLE VI

Term

6.1 This contract shall become effective upon the execution hereof and the approval of the Alaska Royalty Oil and Gas Development Advisory Board and the State Legislature and shall continue and remain in effect until July 1, 1984, unless terminated or extended prior to such date by mutual agreement of the parties, or pursuant to Article VII.

ARTICLE VII

Conditions Precedent and Force Majeure

7.1 Buyer shall have the right to terminate this contract upon 30 days written notice to Seller if Buyer is unable to make satisfactory arrangements to take delivery of the gas. Buyer shall exercise this right to terminate on or before June 30, 1978, thereafter Buyer may not exercise this right to terminate.

7.2 It is expressly recognized and agreed that the gas gathering system utilized for deliveries hereunder is operated and maintained by Lessee for its own purpose and that Lessee will not dedicate any facilities or otherwise undertake to render any service to or for the public. This Agreement is being undertaken solely to effectuate the delivery of royalty gas which Buyer is purchasing from the State of Alaska, and the parties hereto make the material representation that neither this Agreement nor Buyer's use or disposition of the gas delivered hereunder will subject Lessee to regulation by the Federal Power Commission or the Alaska Public Utilities Commission or the Alaska Pipeline Commission.

7.3 Force Majeure

7.3.1 No liability shall result to either party from delay in performance or non-performance of any obligation hereunder (except Buyer's obligation to make payment hereunder) caused by circumstances reasonably beyond the control of the party affected, including, but not limited to, acts of God, fire, flood, storm, war (declared or undeclared), breakage or accident to machinery or lines of pipe, repair, redrilling or reworking of wells, governmental regulation, requisition or direction, or labor strikes or lockouts.

7.3.2 The party claiming relief under this Article VII shall advise the other party with reasonable promptness in writing giving full particulars of the cause or causes relied upon and shall also give prompt notice in writing of the cessation of any such cause or causes. The party claiming force majeure shall exercise due diligence in undertaking to remedy and overcome the cause of delay hereunder, but neither

party shall be required to agree to any demand of labor to settle any strike or labor dispute except in the sole discretion of the party subject to such strike or labor dispute.

ARTICLE VIII

Miscellaneous

8.1 The terms and provisions of this Agreement shall extend to and be binding upon the parties hereto, their assigns and successors in interest. It is understood, however, that Buyer may not assign its rights and interest in this Agreement without the written consent of Seller, except as may be necessary to Buyer to conform with its various financing documents or as may be desirable to Buyer as to its commonly owned affiliate or subsidiary. No assignment shall relieve any assignor of this Agreement of its obligations hereunder without the written consent of Seller.

ARTICLE IX

Notices

9.1 Notices required to be given under this contract shall be deemed sufficiently given and served when and if deposited in the United States mail postage prepaid and certified or registered addressed to Seller at:

Commissioner

Department of Natural Resources

Pouch M, Juneau, Alaska 99811

or to Buyer at:

Alaska Pipeline Company

P. O. Box 6288

Anchorage, Alaska 99502

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in four (4) original counterparts on this day and year first above written.

"BUYER"

_____

ATTEST:

_____

STATE OF ALASKA

_____

ATTEST:

_____

1/11/77

Phillips is "hooked" with by APC & HEA deal

42.05.701

[2] "public utility" & "utility" includes every corporation ---------- that owns, operates, manages or controls any plant, pipeline or system for

D. furnishing by transmission or distribution of natural or manufactured gas to the Alaska public for compensation

42.05.701

[5] "public" or "general public" means

A any group of 10 or more customers that purchase the service or commodity furnished by a utility as defined in [2] of this section; and

B any utility purchasing the product or service or paying for the transmission of electric energy, natural ~~gas~~ or manufactured gas, or petroleum products which are resold to a group included in [A] of this para or which are used to produce the service or commodity sold to the public by the utility.

The commission, on a finding that no legitimate public interest will be served, may exempt a utility from all or any part of this chapter

when a compressor installed.

GAS GATHERING AGREEMENT

THIS AGREEMENT, made and entered into this _____ day of _____, 1976, between ALASKA PIPELINE COMPANY, herein referred to as "APC," and PHILLIPS PETROLEUM COMPANY, herein referred to as "Phillips,"

W I T N E S S E T H:

WHEREAS, APC has entered into a contract dated June 4, 1976, with the State of Alaska to purchase the State's royalty gas produced from the North Cook Inlet Field, a copy of which is attached hereto as Exhibit "A", and

WHEREAS, said contract provides that APC will accept said royalty gas at or near the wellhead in the North Cook Inlet Field, and

WHEREAS, Phillips operates a gas pipeline used to gather natural gas from the North Cook Inlet Field to the Kenai LNG Plant, and

WHEREAS, Phillips is willing to gather on a best efforts basis said royalty gas for APC and deliver same to APC at a mutually agreeable point near the Kenai LNG Plant, and

WHEREAS, the parties hereto recognize that it will be necessary for Phillips to provide substantial additional compression capacity over that otherwise required in order to handle the royalty gas through its gathering system, and

See Article IX, Sec 2

WHEREAS, APC represents that the quantity of gas contemplated per Exhibit "A" does not offer adequate feasibility for APC to justify participation in the installation of said additional compression capacity (or any other method of taking delivery of said royalty gas (like building its own gasline) except to the extent it may be available from time to time, and (this must refer to APC's agreement to accept royalty gas on the basis of surplus capacity)

See March 3, 1977 letter to Don Wold by Phillips

WHEREAS, APC further represents that for reasons stated above APC cannot justify investment to deliver said royalty gas to other than APC's existing and potential new customers in the vicinity of the Kenai LNG Plant (as contrasted

1. Identify amount to be delivered?
2. Detail cost of movement to ~~store~~ delivery point - compression cost etc.?
3. When compressor installed? does state have control?
4. details of agreement —

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to delivering into APC's transmission system to Anchorage);

NOW THEREFORE, premises considered, the parties hereto mutually agree that:

ARTICLE I

DEFINITIONS

1. The term "day" shall mean a period of twenty-four (24) consecutive hours beginning and ending at 7:00 o'clock A.M. The reference date for any day shall be the date of the beginning of such day.

2. The term "month" shall mean a period beginning at 7:00 o'clock A.M. on the first day of a calendar month and ending at 7:00 o'clock A.M. on the first day of the next succeeding calendar month.

3. The term "Mcf" shall mean one thousand (1,000) cubic feet of natural gas measured as hereinafter provided.

ARTICLE II

FACILITIES

1. Phillips is presently operating and maintaining a natural gas gathering system between the North Cook Inlet Field and the Kenai LNG Plant.

2. APC agrees to install, maintain and operate all pipeline, pressure regulators, and related facilities necessary to receive gas hereunder at the point of delivery hereinafter specified. Said point of delivery shall be at or near the existing pipeline tap presently being used to deliver gas from Phillips' pipeline to the Tesoro refinery located in the general vicinity of the Kenai LNG Plant on the North Kenai Road. APC agrees to extend its gathering line from said point of delivery to its existing metering station also located in the general vicinity of the North Kenai Road (hereinafter called "the point of measurement").

See Article IV 1.

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3. APC hereby grants unto Phillips (or its designated agent) such rights of way and surface easements and rights of ingress and egress on its property or shall provide surface easements as may be required to install, maintain and operate the facilities necessary to facilitate delivery of gas by Phillips hereunder to the point of delivery and to APC's measuring station above mentioned.

4. APC agrees to install, operate and maintain all necessary equipment at the point of delivery and at APC's measuring station to properly control, odorize, and measure the volumes of gas delivered hereunder.

ARTICLE III

QUANTITY OF GAS

1. Subject to the availability of capacity in its facilities to handle volumes in excess of its own needs and to the extent of such availability, and upon proper written notice from APC, Phillips shall gather the royalty gas in the North Cook Inlet Field and deliver same to APC at the point of delivery specified herein. APC is entitled to receive at the wellhead all of the royalty gas owned by the State of Alaska and produced from the North Cook Inlet Field, and to the extent that Phillips gathers less than the total available, that difference shall be carried in the over and short account described below or Phillips shall purchase same on the basis provided in Section 2 below.

It is recognized that it is impossible to deliver to APC the exact amount of royalty gas as produced from the North Cook Inlet Field. Phillips agrees that it will carry an over and short account with respect to the receipts of royalty gas and the delivery of same to APC; provided however, that Phillips shall never be required to carry more than a total of 60,000 Mcf over or under-delivery. In the event the takes by APC on a cumulative basis shall ever be

more than 60,000 Mcf less than the deliveries of royalty gas, APC shall not be allowed to make up for any such underdelivery.

2. The parties recognize that APC may be unable from time to time to take and deliver to its customers the full volumes of gas attributable to the State's royalty interest although it is committed to purchase that volume from the State. In such event, Phillips agrees to purchase from APC from time to time those volumes, delivered at the wellhead, which APC is unable to take. For such volumes which it purchases from APC, Phillips will pay APC a price equal to that amount which Phillips would have otherwise paid the State of Alaska as royalty if the State had not elected to receive its royalty gas in kind.

ARTICLE IV

POINT OF DELIVERY AND OWNERSHIP

1. Point of delivery to APC for all gas gathered and delivered hereunder by Phillips shall be at the juncture of APC's facilities and Phillips' facilities located near the pipeline tap serving the Tesoro refinery as mentioned above.

2. Phillips shall be deemed to be in control and possession of the gas deliverable hereunder and responsible for any damage or injury caused thereby until said gas shall have been delivered to APC at the point of delivery, after which delivery APC shall be deemed to be in exclusive control and possession of the gas and responsible for any injury or damage caused thereby.

3. APC shall be responsible for any gas lost between the point of delivery and the point of measurement.

ARTICLE V

DELIVERY PRESSURE

1. Phillips shall deliver gas hereunder at the pressure existing from time to time in its facilities at the point of delivery.

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ARTICLE VI

QUALITY OF GAS

1. Phillips agrees that the gas, when delivered at the point of delivery hereunder, shall be the quality of gas existing in its gathering system from time to time and APC agrees to accept such gas.

2. It is understood that the gas delivered hereunder will not be odorized by Phillips, and if APC so utilizes the gas delivered hereunder for purposes which require odorization of such gas, the full responsibility for such use is APC's and APC agrees to comply with all laws and regulations respecting the odorization of such gas and hereby indemnifies and holds Phillips harmless from any and all claims, injuries, expenses, penalties and damages arising out of or connected with APC's failure to observe strictly and comply with all laws, rules and regulations with respect hereto.

ARTICLE VII

STANDARDS OF MEASUREMENT AND TESTS

1. Except for the determination and computation of total heating value, the unit of volume of gas delivered hereunder shall be one (1) cubic foot at an absolute pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch and at a base temperature of sixty (60) degrees Fahrenheit.

2. The volumes of gas delivered hereunder shall be measured and computed by APC in accordance with the methods prescribed in Gas Measurement Committee Report No. 3, Natural Gas Department, American Gas Association, including the Appendix thereto, dated April, 1955, except that the atmospheric pressure shall be assumed to be fourteen and seven-tenths (14.7) pounds per square inch. The method used for correcting such volumes for deviation from the Ideal Gas Laws

shall be the procedure recommended in the most current Report of the American Gas Association or by any other method mutually agreeable to the parties hereto.

3. The specific gravity of the gas delivered hereunder shall be determined by Phillips utilizing the method prescribed in American Petroleum Institute Code No. 50-A at the beginning of delivery hereunder and once during each month thereafter. The results of each such determination shall be used in computing the volume of gas delivered hereunder until the effective date of the next succeeding test.

4. The flowing temperature of the gas delivered hereunder shall be determined by means of a continuous recording thermometer installed by APC so that it will properly record the temperature of the gas flowing through the meter. The arithmetical average of the hourly temperatures recorded each day shall be used in computing the volumes of gas delivered during such day.

5. If the gas delivered hereunder is solely from the 16-inch pipeline serving the North Cook Inlet Field, the total heating value of the gas shall be the average of that recorded on the recording calorimeter for Phillips' gas at the inlet to Kenai LNG Plant during the billing period corrected to thirty (30) inches of Mercury and sixty (60) degrees Fahrenheit dry.

ARTICLE VIII

MEASUREMENT

1. As agreed in Section 2 of Article II hereof, APC shall be obligated to and responsible for all metering of gas hereunder.

2. Phillips may, at its option and expense, install check meters upstream or downstream of APC's meter station provided that such check meters will be installed so as not to interfere with the operation of APC's facilities. The calibrating and adjusting of Phillips' meters and the changing of charts and the reading of charts on Phillips' meters shall be done by Phillips.

3. APC and Phillips shall have access at all times to APC's metering equipment including all other instruments used by APC in determing the measurement and quality of the gas delivered hereunder, but the reading, calibrating and adjusting thereof, and the changing of charts shall be done only by the employees, agents, or representatives of APC. Upon request of Phillips, APC shall submit to Phillips records and charts from such equipment subject to return by Phillips within thirty (30) days after receipt thereof.

4. At least once a month APC shall test its above mentioned metering equipment or cause the same to be tested and APC shall give Phillips or Phillips' representative reasonable prior notice of the time all such tests are to be made so that Phillips may, if desired, have its representative present to observe such tests and any adjustments made upon such metering equipment. Following any test, any of APC's metering equipment found to be inaccurate to any degree shall be adjusted immediately to measure accurately. If upon any test such metering equipment is found to be inaccurate by two percent (2%) or more, registration from said metering equipment and any payments based upon such registrations shall be corrected at the rate of such inaccuracy for any period of inaccuracy which is definitely known or agreed upon, but in case the period is not definitely known or agreed upon, then for a period extending back one-half of the time elapsed since the last previous test, not exceeding however fifteen (15) days.

5. If for any reason APC's meter is out of service or is found registering inaccurately and the error is not determinable by ordinary test such that the volume of gas delivered through such meter cannot be ascertained or computed from the readings thereof, the volume of gas so delivered during the period the meter is out of service or registering inaccurately shall be estimated and

agreed upon by the parties hereto upon the basis of the best available data, using the first of the following methods which is feasible:

(a) By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation;

(b) By using the registration of any check measuring equipment of Phillips if installed and registering accurately;

(c) By estimating the volume by comparing it with deliveries during preceding periods under similar conditions when the meter was registering accurately.

ARTICLE IX

GATHERING AND COMPRESSION CHARGES AND TAXES

1. For all gas delivered by Phillips to APC at the delivery point, APC shall pay to Phillips the amount of ten cents (10.0¢) per Mcf as consideration for dehydration and delivery of such royalty gas onshore, at the point of delivery, rather than at Phillips' North Cook Inlet platform. The above stated charge shall increase by six percent (6%) on each anniversary date of this Agreement.

2. It is recognized by the parties hereto that it will be necessary for Phillips to install compression facilities during the term of this Agreement. At the time the first compressor unit (approximately 3500 h.p.) is installed and ready for operation, APC shall pay Phillips in addition to the gathering charge set forth in Section 1 of this Article IX, a compression charge of ten cents (10.0¢) per Mcf for all gas delivered by Phillips to APC at the delivery point. Such charge shall increase by six percent (6%) per year, commencing on

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the first anniversary of the date such compression facilities are installed and ready for operation.

3. In the event that Phillips installs or causes to be installed compression facilities in addition to those mentioned in Section 2, then the parties shall make a good faith effort to agree on the compression charge applicable for each such additional compressor. The basis for arriving at such additional compression charge shall be as follows:

> Phillips shall determine the appropriate share of the cost of said facilities which should be chargeable to APC, in the relationship of the anticipated volume of deliveries to be made to APC during the year as compared to the anticipated total volume of deliveries to be made by Phillips through these facilities for each such year. Phillips shall timely furnish this information to APC in writing.

In the event APC should dispute Phillips' determination of the cost share appropriately chargeable to APC for any such additional compression installation, APC may elect to give one (1) year's notice of termination of this Agreement, but APC shall, until such termination, still be liable to pay to Phillips the cost share appropriately chargeable to APC during the period of such notice of termination. In the event APC does not dispute Phillips' determination of the cost share appropriately chargeable to APC for any additional compressor installation within ninety (90) days of said determination, then APC shall thereby forefeit its right to elect to give notice of termination of this Agreement and shall continue to make said payment to Phillips for the remainder of the term hereof.

Nothing herein shall be construed by either party as an obligation

on Phillips to install any compression facilities whatever or to operate any compression facilities already installed.

5. Phillips shall pay all ad valorem taxes on its pipelines and facilities employed in delivering gas hereunder. In addition to the price and payments hereinabove provided, APC shall reimburse Phillips in the proportion of deliveries made to APC by Phillips, an amount equal to the aggregate total of any new or increased fee, impost, duty, charge, excise or tax levied or imposed in addition to the rates at which those, if any, are levied, assessed, or fixed as of the date hereof, with respect to the gathering of the gas delivered hereunder (including compression) prior to its delivery to APC that Phillips may be required to pay directly or indirectly.

ARTICLE X

BILLING AND PAYMENTS

1. On or before the 15th day of each month during the term hereof APC shall furnish Phillips with a full and complete statement reflecting all gas delivered by Phillips during the preceding month and the total amount due hereunder pursuant to Article IX hereof. Payment hereunder shall be made by APC to Phillips at its office in Bartlesville, Oklahoma within ten (10) days after delivery of each such statement.

2. On or before the 30th day of each month during the term hereof Phillips shall furnish to APC a full and complete statement reflecting the total amount of royalty gas produced by Phillips during the preceding month. Deducting the quantity taken by APC for such month, Phillips shall determine the amount of royalty gas not taken by APC for such month and shall make payment therefor to APC together with said statement.

ARTICLE XI

REPRESENTATION AND CONDITION PRECEDENT

It is expressly recognized and agreed that the gas gathering system utilized for deliveries hereunder is operated and maintained by Phillips for its own purpose and Phillips does not, by entering into this Agreement, dedicate any facilities or otherwise undertake to render any service to or for the public. This Agreement is being undertaken solely to effectuate the delivery of royalty gas which APC is purchasing from the State of Alaska, and APC makes the material representation that neither this Agreement nor APC's use or disposition of the gas delivered hereunder will subject Phillips to regulation by the Federal Power Commission or the Alaska Public Utilities Commission.

The parties shall co-operate to make the necessary filings with the Alaska Public Utilities Commission in order to secure a declaration by that agency that Phillips will not become a utility subject to regulation by such commission by virtue of the activities performed hereunder.

If such declaration of the non-utility status of Phillips has not been received in a form satisfactory to Phillips within ninety (90) days after the execution hereof, then either party shall have the option to terminate this Agreement upon thirty (30) days' notice in writing.

It is further expressly recognized that APC's contract with the State of Alaska (Exhibit "A") must be amended to conform with the provisions of this Agreement, and that if such amendment has not been obtained in a form satisfactory to APC and Phillips within ninety (90) days after the execution hereof, then either party shall have the option to terminate this Agreement upon thirty (30) days' notice in writing.

AGO 801688

ARTICLE XII

FORCE MAJEURE

1. No liability shall result to either party from delay in performance or non-performance of any obligation hereunder (except APC's obligation to make payment hereunder) caused by circumstances reasonably beyond the control of the party affected, including, but not limited to, acts of God, fire, flood, storm, war (declared or undeclared), breakage or accident to machinery or lines of pipe, repair, redrilling or reworking of wells, governmental regulation, requisition or direction, or labor strikes or lockouts.

2. The party claiming relief under this Article XII shall advise the other party with reasonable promptness in writing giving full particulars of the cause or causes relied upon and shall also give prompt notice in writing of the cessation of any such cause or causes. The party claiming force majeure shall exercise due diligence in undertaking to remedy and overcome the cause of delay hereunder, but neither party shall be required to agree to any demand of labor to settle any strike or labor dispute except in the sole discretion of the party subject to such strike or labor dispute.

ARTICLE XIII

TERM

1. This Agreement shall be effective from the date hereof and shall extend until June 1, 1984, unless sooner terminated as provided hereinabove.

ARTICLE XIV

MISCELLANEOUS

1. Except as herein otherwise provided, any notice, request, demand, statement or bill provided for in this Agreement, or any notice which either

AGO 801689

party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered mail to either of the parties hereto as the case may be at the following address:

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

Phillips Petroleum Company
Attention: Gas and Gas Liquids Division
Bartlesville, Oklahoma 74004

or at such other address as either party shall designate from time to time by formal written notice. Routine communications, including monthly statements and payments, shall be considered as duly delivered when mailed by either registered or ordinary mail.

2. Each party shall have the right to examine at reasonable times the books, records, and charts of the other party to the extent necessary to verify the accuracy of any statement, charge, computation or demand made under or pursuant to any of the provisions of this Agreement.

3. The terms and provisions of this Agreement shall extend to and be binding upon the parties hereto, their assigns and successors in interest. It is understood, however, that APC may not assign its rights and interest in this Agreement without the written consent of Phillips, except as may be necessary to APC to conform with its various financing documents or as may be desirable to APC as to its commonly owned affiliate or subsidiary. No assignment shall relieve any assignor of this Agreement of its obligations hereunder without the written consent of Phillips.

IN WITNESS WHEREOF, this Agreement is executed as of the day and year first above written.

ATTEST:

ALASKA PIPELINE COMPANY

_____
Assistant Secretary

By_____
President

ATTEST:

PHILLIPS PETROLEUM COMPANY

_____
Assistant Secretary

By_____
Vice President

Signature page to Gas Gathering Agreement dated _____, 1976, by and between ALASKA PIPELINE COMPANY and PHILLIPS PETROLEUM COMPANY.

L. Fab

Don Wold
cc: Board
1-21-77

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 Anchorage, Alaska 99502 / Phone (907) 277-555
Telex 25-187

RECEIVED
DEC 20 1976
ALASKA ROYALTY
OIL & GAS BOARD

December 15, 1976

RECEIVED
DEC 17 1976
Department of
Natural Resources

Alaska Public Utilities Commission
1100 MacKay Building
338 Denali Street
Anchorage, Alaska 99501

Dear Commissioners:

On December 2 we wrote asking for the earliest possible scheduling of a hearing on the subject of waiving jurisdiction over Phillips Petroleum Company's delivery of royalty gas to us.

In view of the lateness of the season and the lack of frozen ground (swamp) and the estimated time for obtaining right of way and other uncertainties, we wish now to withdraw our request for scheduling an early hearing. We cannot justify ordering the pipe ($600,000) etc. at present.

We still hope to complete this project during 1977, and we will in due course again be requesting the waiver of jurisdiction, but it is not now regarded to be as urgent as indicated to you previously.

Very truly yours,

Dale Teel

cc: Mr. John Horn
Phillips Petroleum Co.
Bartlesville, Oklahoma 74004

Commissioner Guy Martin
Department of Natural Resources
State of Alaska
Juneau, Alaska 99801

Alaska Gas and Service Company

GENERAL OFFICES LOCATED AT 3000 SPENARD ROAD
P. O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-5551
TELEX 25-187

September 29, 1976

Alaska Public Utilities Commission
1100 MacKay Building
338 Denali Street
Anchorage, Alaska 99501

Dear Commissioners:

Order No. 5 of U-75-68 requires a report on the status of our purchasing royalty gas from the State of Alaska, by October 15. The matter of royalty gas availability was mentioned in Order No. 7 of U-75-95 as part explanation for setting a return on equity of only 14.25% for us, which in our opinion is inadequate.

Negotiations for royalty gas have had to be done intermittently because of the heavy attention required for U-75-95. We have had several meetings with Phillips and others regarding royalty gas, and still have some hope to reach a satisfactory conclusion. Our alternative would be to continue utilizing "Anchorage" reserves to supply our customers in the North Kenai Road area. This would avoid the need for further investment and the higher cost of gas.

If we can anticipate sufficient return and if we can obtain the necessary financing, we would of course want to proceed to obtain royalty gas as being a better, longer-term solution to this matter. But it became less feasible to us and less favorable to the public interest than we once envisioned because of three aspects of the contract with the State (copy which is enclosed):

(1) The price is set to be equal to the highest of the defined area, whereas we hoped it would never be higher than the price of gas to be liquefied for Japan.

(2) The state requires that we take 100% of the royalty gas although we do not have sales on the North Kenai Road for the full amount; we do not have facilities to interconnect with our pipeline to Anchorage; and we are not able to obtain an "exchange" agreement for gas at the Kenai field.

Alaska Gas and Service Company
GENERAL OFFICES LOCATED AT 3000 SPENARD ROAD
P.O. BOX 6388 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-5551
TELEX 25-167

(3) The contract term is limited to the term of the sale to Tokyo -- June 30 of 1984 -- which sharply limits the feasibility of investing for facilities. We had asked for this royalty for "the life of production."

Phillips has asked that we fund all of the first phase of a compressor station on their platform, estimated at $5 million, as a condition for delivering the royalty to us onshore. We have countered with an offer to pay a pro-rata (volume) share for compression with a right to discontinue after one year's notice, and an offer to resell "excess" royalty gas back to Phillips at the price they would otherwise have paid to the State, and to forego taking royalty gas if (and while) pipeline capacity is a limitation. We will require a standby gas supply during such periods when royalty is not available. We have not been able to obtain such a supply and may have to build a pipeline from our existing line (to Anchorage) for this purpose. It is here that allowable rate of return and financing became essential to the decision.

We do not believe it is practical to develop "a complete record" of the negotiations for the Commission's files on this matter, but we would welcome an opportunity to discuss it informally at the convenience of the Commission. Clearly we do need to preserve the flow through provision in order to continue our negotiations, which apparently will require several more months.

Very truly yours,

Dale Teel
President

dh

Enclosure

RECEIVED

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 Anchorage, Alaska 99502 / Phone (907) 277-5551
Telex 25-187

August 31, 1976

Mr. John Horn
Gas and Gas Liquids Division
Phillips Petroleum Company
Bartlesville, Oklahoma 74004

Dear John:

Here is a retyped and slightly edited version of a contract draft we hope you can accept on our effort to purchase the royalty gas from the North Cook Inlet gas field. You will particularly note the additions which are underlined in red on the marked-up copy.

I will approach the State Royalty Board on this matter at the earliest opportunity. I believe that if I had a letter from you effectively accepting this draft, they would approve it. I will also re-open with the APUC (after September 17 and their action in the pending rate case).

I will begin discussions with Tesoro later this week, and hope to obtain "standby" supply for "firm" customers (or more) also within the near future. While it may be most difficult to obtain all these concurrences in time for the necessary construction this fall, I will continue to hope that it is possible and will proceed on that basis as long as there is any chance.

We appreciate the attention you are giving this matter and hope to get it resolved at the earliest opportunity.

Very truly yours,

Dale Teel

dh

Enclosures

bcc: Alaska Public Utilities Commission

GAS GATHERING AGREEMENT

RECEIVED
A.P.U.C.
SEP 2 10 19 AM '76

THIS AGREEMENT, made and entered into this _____ day of _____, 1976, between ALASKA PIPELINE COMPANY, herein referred to as "APC", and PHILLIPS PETROLEUM COMPANY, herein referred to as "Phillips",

W I T N E S S E T H:

WHEREAS, APC has entered into a contract dated June 4, 1976 with the State of Alaska to purchase the State's royalty gas produced from the North Cook Inlet Field, a copy of which is attached hereto as Exhibit "A" and made a part hereof, and

WHEREAS, said contract provides that APC will accept said royalty gas at or near the wellhead in the North Cook Inlet Field, and

WHEREAS, Phillips operates a gas pipeline used to gather natural gas from the North Cook Inlet Field to the Kenai LNG Plant, and

WHEREAS, the parties hereto recognize that it would be necessary for Phillips to provide substantial additional compression capacity over that otherwise required in order to handle the royalty gas through its gathering system, and

APC contract with State

WHEREAS, the parties hereto further recognize that the quantity of gas contemplated per Exhibit "A" does not offer adequate feasibility for APC to justify participation in the installation of said additional compression capacity or any other method of taking delivery of said royalty gas except to the extent it may be available from time to time at the discretion of Phillips, and

WHEREAS, the parties hereto also recognize that for reasons stated above APC cannot justify investment to deliver said royalty gas to other than APC's existing and potential new customers in the vicinity of the Kenai LNG plant (as contrasted to delivering into APC's transmission system to Anchorage);

NOW THEREFORE, premises considered, the parties hereto mutually agree that:

ARTICLE I

DEFINITIONS

1. The term "day" shall mean a period of twenty-four (24) consecutive hours beginning and ending at 7:00 o'clock A.M. The reference date for any day shall be the date of the beginning of such day.

2. The term "month" shall mean a period beginning at 7:00 o'clock A.M. on the first day of a calendar month and ending at 7:00 o'clock A.M. on the first day of the next succeeding calendar month.

3. The term "MCF" shall mean one thousand (1,000) cubic feet of natural gas measured as hereinafter provided.

ARTICLE II

FACILITIES

1. Phillips is presently operating and maintaining a natural gas gathering system between the North Cook Inlet Field and the Kenai LNG Plant.

2. APC agrees to install, maintain and operate all pipeline, pressure regulators, and related facilities necessary to receive gas hereunder at the point of delivery hereinafter specified. Said point of delivery shall be at the existing pipeline tap presently being used to deliver gas from Phillips pipeline to the Tesoro refinery located in the general vicinity of the Kenai LNG plant on the North Kenai Road. APC agrees to extend its gathering line from said point of delivery to its existing metering station also located in the general vicinity of the North Kenai Road (hereinafter called "the point of measurement"), with a check valve also being installed at said point of delivery.

3. APC hereby grants unto Phillips (or its designated agent) such rights of way and surface easements on its property or shall provide surface easements as may be required to install, maintain

and operate the measuring and related facilities necessary to facilitate delivery of gas by Phillips hereunder to the point of delivery and to APC's measuring station above mentioned.

4. APC agrees to install, operate and maintain all necessary equipment at the point of delivery and at APC's measuring station to properly control, odorize, and measure the volumes of gas delivered hereunder.

ARTICLE III

QUANTITY OF GAS

1. Subject to the stipulations and conditions herein and upon proper written notice from APC, Phillips shall gather the royalty gas in the North Cook Inlet Field and deliver such gas to APC at the point of delivery specified herein. APC is entitled to receive at the wellhead all of the royalty gas owned by the State of Alaska and produced from the North Cook Inlet Field, subject to Phillips' discretion because of limitations resulting from Phillips' requirement for additional compression facilities and because of APC's inability to take delivery of all of the royalty gas for its customers in the vicinity of the North Kenai Road.

It is recognized that it is impossible to deliver to APC the exact amount of royalty gas as produced from the North Cook Inlet Field. Phillips agrees that it will carry an over and short account with respect to the receipts of royalty gas and the delivery of same to APC; provided however, that Phillips shall never be required to carry more than a total of 60,000 MCF over or underdelivery. In the event the takes by APC on a cumulative basis shall ever be more than 60,000 MCF less than the deliveries of royalty gas, APC shall not be allowed to make up for any such underdelivery.

2. Except as provided above, APC agrees to sell to Phillips at the price otherwise payable by Phillips directly to the State

of Alaska for this royalty gas, any of the royalty gas which APC is unable to take and deliver to its customers in the vicinity of the North Kenai Road, and any of the royalty gas which Phillips is unable, at its discretion, to deliver to APC by reason of transmission (or compression) capacity available from time to time.

ARTICLE IV

POINT OF DELIVERY AND OWNERSHIP

1. Point of delivery to APC for all gas gathered and delivered hereunder by Phillips shall be at the pipeline tap serving the Tesoro refinery as mentioned above.

2. Phillips shall be deemed to be in control and possession of the gas deliverable hereunder and responsible for any damage or injury caused thereby until said gas shall have been delivered to APC at the point of delivery, after which delivery APC shall be deemed to be in exclusive control and possession of the gas and responsible for any injury or damage caused thereby.

3. APC shall be deemed to be responsible for any gas lost between the point of delivery and the point of measurement.

ARTICLE V

DELIVERY PRESSURE

1. Phillips shall deliver gas hereunder at the pressure existing from time to time in its facilities at the point of delivery.

ARTICLE VI

QUALITY OF GAS

1. Phillips agrees that the gas, when delivered at the point of delivery hereunder, shall be the quality of gas existing in its gathering system from time to time and APC agrees to accept such gas.

2. It is understood that the gas delivered hereunder will not be odorized by Phillips, and if APC so utilizes the gas delivered hereunder for purposes which require odorization of such gas, the full

responsibility for such use is APC's and APC agrees to comply with all laws and regulations respecting the odorization of such gas and hereby indemnifies and holds Phillips harmless from any and all claims, injuries, expenses, penalties and damages arising out of or connected with APC's failure to observe strictly and comply with such laws, rules and regulations with respect hereto.

ARTICLE VII

STANDARDS OF MEASUREMENT AND TESTS

1. Except for the determination and computation of total heating value, the unit of volume of gas delivered hereunder shall be one (1) cubic foot at an absolute pressure of fourteen and sixty-five hundredths (14.65) pounds per squre inch and at a base temperature of sixty (60) degrees Fahrenheit.

2. The volumes of gas delivered hereunder shall be measured and computed by APC in accordance with the methods prescribed in Gas Measurement Committee Report No. 3, Natural Gas Department, American Gas Association, including the Appendix thereto, dated April, 1955, except that the atmospheric pressure shall be assumed to be fourteen and seven tenths (14.7) pounds per square inch. The method used for correcting such volumes for deviation from the Ideal Gas Laws shall be the procedure recommended in the most current Report of the American Gas Association or by any other method mutually agreeable to the parties hereto.

3. The specific gravity of the gas delivered hereunder shall be determined by Phillips utilizing the method prescribed in American Petroleum Institute Code No. 50-A at the beginning of delivery hereunder and once during each month thereafter. The results of each such determination shall be used in computing the volume of gas delivered hereunder until the effective date of the next succeeding test.

4. The flowing temperature of the gas delivered hereunder shall be determined by means of a continuous recording thermometer installed

by APC so that it will properly record the temperature of the gas flowing through the meter. The arithmetical average of the hourly temperatures recorded each day shall be used in computing the volumes of gas delivered during such day.

5. If the gas delivered hereunder is solely from the 16-inch pipeline serving the North Cook Inlet Field, the total heating value of the gas shall be the average of that recorded on the recording calorimeter for Phillips' gas at the inlet to Kenai LNG Plant during the billing period corrected to thirty (30) inches of Mercury and sixty (60) degrees Fahrenheit dry.

ARTICLE VIII

MEASUREMENT

1. Phillips may, at its option and expense, install check meters upstream or downstream of APC's meter station provided that such check meters will be installed so as not to interfere with the operation of APC's facilities. The calibrating and adjusting of Phillips' meters and the changing of charts and the reading of charts on Phillips' meters shall be done by Phillips.

2. APC and Phillips shall have access at all times to APC's metering equipment including all other instruments used by APC in determining the measurement and quality of the gas delivered hereunder, but the reading, calibrating and adjusting thereof, and the changing of charts shall be done only by the employees, agents, or representatives of APC. Upon request of Phillips, APC shall submit to Phillips records and charts from such equipment subject to return by Phillips within thirty (30) days after receipt thereof.

3. At least once a month APC shall test its above mentioned metering equipment or cause the same to be tested and APC shall give Phillips or Phillips' representative reasonable prior notice of the time all such tests are to be made so that Phillips may, if desired, have its representative present to observe such tests and any adjustments made upon such metering equipment. Following any test, any of APC's metering equipment found to be inaccurate to any degree shall be adjusted immediately to measure accurately. If upon any test such metering equipment is found to be inaccurate by two percent (2%) or

more, registration from said metering equipment and any payments based upon such registrations shall be corrected at the rate of such inaccuracy for any period of inaccuracy which is definitely known or agreed upon, but in case the period is not definitely known or agreed upon, then for a period extending back one-half of the time elapsed since the last previous test, not exceeding however fifteen (15) days.

4. If for any reason APC's meter is out of service or is found registering inaccurately and the error is not determinable by ordinary test such that the volume of gas delivered through such meter cannot be ascertained or computed from the readings thereof, the volume of gas so delivered during the period the meter is out of service or registering inaccurately shall be estimated and agreed upon by the parties hereto upon the basis of the best available data, using the first of the following methods which is feasible:

(a) By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation;

(b) By using the registration of any check measuring equipment of Phillips if installed and registering accurately;

(c) By estimating the volume by comparing it with deliveries during preceding periods under similar conditions when the meter was registering accurately.

Exhibit 12D Full Share Royalty

ARTICLE IX

GATHERING CHARGE AND TAXES

1. It is recognized by the parties hereto that it may be necessary for Phillips to install compression facilities during the term of this Agreement. In the event Phillips does install such compression facilities, then Phillips shall be entitled to determine the appropriate share of the cost of said facilities which should be chargeable to APC, in the relationship of the volume of deliveries made to APC during the prior year as compared to the total volume of deliveri made by Phillips through these facilities for that prior year. Upon

Phillips' determination of the cost share for these facilities which is appropriately chargeable to APC, APC shall have twelve (12) months during which to make payment to Phillips therefor, by equal monthly installments.

In the event APC may dispute Phillips' determination of the cost share appropriately chargeable to APC, APC may elect to give one (1) year's notice of termination of this agreement, but APC shall, until such termination, still be liable to pay to Phillips the cost share appropriately chargeable to APC during the period of such notice of termination. In the event APC does not dispute Phillips' determination of the cost share appropriately chargeable to APC within one year of said determination, then APC shall thereby forfeit its right to elect to give notice of termination of this Agreement and shall continue to make said payment to Phillips for the remainder of the term hereof.

Nothing herein shall be construed by either party as an obligation on Phillips to install any compression facilities whatever or to operate any compression facilities already installed.

2. APC shall pay to Phillips the amount of ten cents (10.0¢) per MCF as consideration for dehydration and delivery of the royalty gas onshore, at the point of delivery, rather than at Phillips' North Cook Inlet platform.

3. Phillips shall pay all ad valorem taxes on its pipelines and facilities employed in delivering gas hereunder. In addition to the price and payments hereinabove provided, APC shall reimburse Phillips an amount equal to the aggregate total of any new or increased fee, impost, duty, charge, excise or tax levied or imposed in addition to the rates at which those, if any, are levied, assessed, or fixed as of the date hereof, with respect to the gathering of the gas delivered hereunder prior to its delivery to APC that Phillips may be required to pay directly or indirectly.

ARTICLE X

BILLING AND PAYMENTS

1. On or before the 15th day of each month during the term hereof APC shall furnish Phillips with a full and complete statement reflecting all gas delivered during the preceding month and the total amount due hereunder pursuant to Article IX hereof. Payment hereunder shall be made by APC to Phillips at its office in Bartlesville, Oklahoma, within ten (10) days after delivery of each such statment.

ARTICLE XI

REPRESENTATION AND CONDITION PRECEDENT

It is expressly recognized and agreed that the gas gathering system utilized for deliveries hereunder is operated and maintained by Phillips for its own purpose and Phillips does not, by writing this Agreement, dedicate or otherwise undertake to render any service or facilities to or for the public. This Agreement is being undertaken solely to effectuate the delivery of gas which APC is purchasing from the State of Alaska, and APC makes the material representation that neither this Agreement nor APC's use or disposition of the gas delivered hereunder will subject Phillips to regulation by the Federal Power Commission or the Alaska Public Utilities Commission.

The parties shall co-operate to make the necessary filings with the Alaska Public Utilities Commission in order to secure a declaration by that agency that Phillips will not become a utility subject to regulation by such commission by virtue of the activities performed hereunder.

If such declaration of the non-utility status of Phillips has not been received in a form satisfactory to Phillips within ninety (90) days after the execution hereof, then either party shall have the option to terminate this Agreement upon thirty (30) days' notice in writing.

It is further expressly recognized that APC's contract with the State of Alaska (Exhibit "A") must be amended to conform with the provisions of this Agreement, and that if such amendment has not been obtained in a form satisfactory to Phillips within ninety (90) days after the execution hereof, then either party shall have the option to terminate this Agreement upon thirty (30) days' notice in writing.

ARTICLE XII

CONTINUITY OF SUPPLY

The parties hereto recognize that APC will redeliver said royalty gas to its affiliate Alaska Gas and Service Company, Division of Alaska Interstate Company, for residential, commercial, and industrial purposes as required from time to time. The parties recognize that the industrial purposes can be and must be served on a dual-fuel, interruptible basis so that interruptions will be practicable. The parties further recognize that the residential and commercial purposes have to be served on a "firm" basis (except for force majeure), and that the public health and welfare could be adversely affected in the event of interruptions occurring during periods of winter weather. Accordingly, the parties pledge their good faith to take reasonable and prudent actions to assure a continuity of supply to serve the residential and commercial purposes.

ARTICLE XIII

FORCE MAJEURE

1. No liability shall result to either party from delay in performance or non-performance of any obligation hereunder (except APC's obligation to make payment hereunder) caused by circumstances reasonably beyond the control of the party affected, including, but not limited to, acts of God, fire, flood, storm, war (declared or undeclared), breakage or accident to machinery or lines of pipe, repair, redrilling or reworking of well, governmental regulation, requisition or direction, or labor strikes or lockouts.

2. The party claiming relief under this Article XII shall advise the other party with reasonable promptness in writing giving full particulars of the cause or causes relied upon and shall also give prompt notice in writing of the cessation of any such cause or causes. The party claiming force majeure shall exercise due diligence in undertaking to remedy and overcome the cause of delay hereunder, but neither party shall be required to agree to any demand of labor to settle any strike or labor dispute except in the sole discretion of the party subject to such stike or labor dispute.

ARTICLE XIV

TERM

1. This Agreement shall be effective from the date hereof and shall extend until June 1, 1984.

ARTICLE XV

MISCELLANEOUS

1. Except as herein otherwise provided, any notice, request, demand, statement or bill provided for in this Agreement, or any notice which either party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered mail to either of the parties hereto as the case may be at the following address:

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

Phillips Petroleum Company
Attention: Gas and Gas Liquids Division
Bartlesville, Oklahoma 74004

or at such other address as either party shall designate from time to time by formal written notice. Routine communications, including monthly statements and payments, shall be considered as duly delivered when mailed by either registered or ordinary mail.

2. Each party shall have the right to examine at reasonable times the books, records, and charts of the other party to the extent necessary to verify the accuracy of any statement, charge, computation or demand made under or pursuant to any of the provisions of this Agreement.

3. The terms and provisions of this Agreement shall extend to and be binding upon the parties hereto, their assigns and successors in interest. It is understood, however that APC may not assign its rights and interest in this Agreement without the written consent of Phillips, except as may be necessary to APC to conform with its various financing documents or as may be desirable to APC as to its commonly - owned affiliate or subsidiary. No assignment shall relieve any assignor of this Agreement of its obligations hereunder without the written consent of Phillips.

IN WITNESS WHREOF, this Agreement is executed as of the day and year first above written.

ATTEST: ALASKA PIPELINE COMPANY

_____ By_____
Assistant Secretary President

ATTEST: PHILLIPS PETROLEUM COMPANY

_____ By_____
Assistant Secretary Vice President

June 11, 1976

Mr. Harold Schmidt
Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

Dear Harold:

Enclosed are two (2) copies of the North Cook Inlet royalty gas sale and purchase contract duly executed for your files.

The entire endeavor should remind us of the old saying "The mills of the gods grind exceedingly slow. . . etc." They have to be almost stationary to be slower than our process. In any case this part is accomplished.

I enjoyed working with you.

Yours truly,

William C. Fackler
Executive Director

Enclosures (2)

WCF:lb

ARCODAB Contract 76-1

Gas Purchase Contract

This Contract, made and entered into this 4th day of June 1976, by and between the Alaska Pipeline Company ("APC") herein referred to as "Buyer" and the State of Alaska, hereinafter referred to as "Seller" :

WITNESSED

WHEREAS, Buyer owns and operates a natural gas pipeline system in areas of Alaska for the delivery of natural gas for ultimate consumption within the State of Alaska, and

WHEREAS, Seller has the right under each of the leases identified at Exhibit "A" attached hereto to be paid by the lessee thereunder a royalty of twelve and one-half percent in kind or in value of the natural gas produced and saved and used off of the lands covered by each such lease, and

WHEREAS, Seller is authorized by AS 38.05.183 to sell royalty gas; and

WHEREAS, Buyer represents to Seller that all gas purchased under this contract will be used to meet the requirements of its customers within the State of Alaska;

NOW, THEREFORE, in consideration of the representations, covenants, and conditions herein contained, Buyer and Seller hereby agree as follows:

AGO 801709

ARTICLE 1

Seller's Royalty Gas

1.1 Seller hereby agrees that within 30 days after the execution and approval of this agreement as required by the laws of the State of Alaska, Seller shall notify the lessee under the leases set forth at Exhibit "A" of this agreement of Seller's election to take its royalty gas in kind. Said notice will provide that the lessee shall commence the delivery of said royalty gas to Seller (or to Seller's designee) upon a receipt of notice from Seller that all facilities necessary to enable Buyer to receive and market said gas are ready; provided, however, in no event shall lessee be required to commence the delivery of royalty gas to Seller (or its designee) prior to six (6) months following lessee's receipt of notice of Seller's election to take its royalty gas in kind.

1.2 In order that Seller can give its lessee as much advance notice as possible of the date it will start receiving its royalty gas in kind, Buyer shall notify Seller, and Seller shall notify its lessee, at least 60 days prior to the date Buyer will receive gas from Seller pursuant to this contract.

ARTICLE II

Quantity

2.1 It is understood and agreed by the parties that the volume of gas available to Seller from the leases covered by this contract depends upon the production from the leases over which Seller has no control. Buyer hereby agrees to purchase on each day commencing with the date of first delivery

AGO 801710

hereunder and continuing during the term of this contract all of Seller's royalty gas available at the point of delivery described in Article III hereof.

ARTICLE III

Delivery Point and Delivery Pressure

3.1 The point of delivery of all gas delivered hereunder shall be at the same point of delivery that Seller receives delivery of its royalty gas from its lessee in the North Cook Inlet Field.

Where is that

3.2 Buyer, at its own expense, shall arrange to accept Seller's gas at the point of delivery.

3.3 Seller will deliver gas received by Seller from lessee at the pressure at which the gas is received by Seller from its lessee.

ARTICLE IV

Quality

4.1 The gas to be delivered by Seller to Buyer at the delivery point shall be gas of the same quality as is delivered to Seller by the lessee at the point of delivery.

AGO 801711

ARTICLE V

Price and Billing

5.1 The price to be paid by Buyer to Seller for gas delivered shall be as follows:

a. Commencing on the date of first deliveries hereunder, assuming that this date occurs prior to July 1, 1977 and continuing until the first day of July 1977, the price shall be 55.5 cents per MCF.

b. Commencing on the first day of July 1977 and continuing until the first day of July 1978 the price shall be the higher of (i) 60.36 cents per MCF, (ii) the price Seller would have received from Phillips Petroleum Company had it not elected to receive its royalty gas in kind, (iii) the highest price paid by any purchaser in the upper Cook Inlet area for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges.

c. For each succeeding 12 month period commencing July 1, 1978 the price shall be increased to the higher of (i) the previous year's price plus 2 cents per MCF, (ii) the price Seller would have received had it not elected to take its

AGO 801712

royalty in kind, (iii) the highest price paid by any purchaser in the upper Cook Inlet area for gas of similar quality and conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges.

5.2 Thirty days prior to the date of each annual price change, Seller, at its option, may determine the price which it would have received from its lessee had it not elected to take its royalty gas in kind and the highest price being paid for gas of similar quality and similar conditions of delivery; with due regard to appropriate factors including, but not limited to, difference of BTU content, delivery pressure, term of the contract and connection charges in the upper Cook Inlet area and submit the same to Buyer along with suitable supporting evidence as to such prices. Buyer shall have the right to submit other evidence within the 30 day period.

5.3 After the delivery of gas has commenced Buyer shall, on or before the 20th day following the end of each month, render to Seller a statement showing the quantity of gas delivered during that month and shall therewith pay Seller the amount due for all such gas.

5.4 Each party hereto shall have, at its expense, the right to examine the books and records of the other party to the extent necessary to verify the accuracy of any statement, charge, computation, or demand made under or pursuant to this

AGO 801713

contract. Any statement shall be final as to both parties unless questioned in writing within two (2) years after payment thereof has been made.

5.5 The terms "upper Cook Inlet area" as used here in shall mean the area encompassed in a radius of 100 kilometers from the Phillips Petroleum North Cook Inlet platform.

ARTICLE VI

Term

6.1 This contract shall become effective upon the execution hereof and the approval of the Alaska Royalty Oil and Gas Development Advisory Board and the State Legislature and shall continue and remain in effect until July 1, 1984, unless terminated prior to such date by mutual agreement of the parties, or pursuant to Article VII.

ARTICLE VII

Conditions Precedent

7.1 Buyer shall have the right to terminate this contract upon 30 days written notice to Seller if Buyer is unable to make satisfactory arrangements to take delivery of the gas. Buyer shall exercise this right to terminate on or before January 31, 1978, thereafter Buyer may not exercise this right to terminate.

ARTICLE VIII

Notices

8.1 Notices required to be given under this contract shall be deemed sufficiently given and served when and if

AGO 801714

deposited in the United States mail postage prepaid and certified or registered addressed to Seller at:

Commissioner
Department of Natural Resources
Pouch M, Juneau, Alaska 99811

or to Buyer at:

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in four (4) original counterparts on this day and year first above written.

"BUYER"

Harold B. Simmons

STATE OF ALASKA

Guy R Martin

ATTEST:

Richard F. Barner

ATTEST:

William C Fuchler

AGO 801715

April 26, 1976

North Cook Inlet Field Royalty Gas
Commissioner's Proposal in Concept

The Commissioner of Natural Resources has recognized that the increasing growth of the Cook Inlet area of Alaska with its resultant increase in the use of natural gas requires that additional natural gas reserves be allocated for that purpose from State of Alaska royalty gas. From the standpoint of size of uncommitted gas reserves, geographical location and possible pipeline access, the North Cook Inlet field royalty gas appears the best available supply at this time. Pursuant to AS 38.05. 182 the Commissioner proposes that it is in the best interest of the State to take in kind the State's royalty share of the gas production from the North Cook Inlet gas field and requests the consent of the Alaska Royalty Oil and Gas Development Advisory Board for this change.

The Commissioner further proposes to dispose of the North Cook Inlet field royalty gas to Alaska Pipeline Company and its subsidiaries through a negotiated contract. The proposed contract will contain the following provisions:

1. Purchaser agrees to take 1/8 of daily production from the North Cook Inlet gas field on an if and as deliverable basis for the contract period. The State will report to the Purchaser each month the amount of royalty gas produced by Phillips during the prior months.

The approximate average daily royalty gas share of the production from Phillips' North Cook Inlet field platform is 17,000 MCF. Gas production from the platform varies as LNG plant needs dictate therefore no daily amount can be specified.

2. Point of delivery will be the wellhead.

3. Purchaser is responsible for measurement costs, and any compression or dehydration costs if or when necessary.

4. The contract expires on June 1, 1984, unless extended by mutual agreement for a period not to exceed one year.

5. The price of the gas will be equal to the price the State otherwise would have received from Phillips for its royalty gas for export as LNG to Japan; but not less than the highest price paid by any purchaser in the Cook Inlet area for a similar sale of gas of similar quality. The price will be adjusted yearly on the anniversary date of the contract.

6. The contract shall not be effective until

-all necessary permits and authorizations by governing bodies are obtained

-all transportation or exchange arrangements have been completed to the satisfaction of the parties involved.

-six month's notice required under lease

The Commissioner request approval of the above proposed conceptual plan by the Alaska Royalty Oil and Gas Development Advisory Board.

North Cook Inlet Field Royalty Gas
Commissioner's Proposal in Concept
Procedure

1. Commissioner determines that the best interests of the State are served by the taking in kind of the State's royalty gas share of the production of the North Cook Inlet gas field.

   Requires consent of the board.

2. Commissioner determines that it would not be in the best interest of the State to sell the North Cook Inlet field royalty gas by competitive bid.

   a. Requires prior written approval by board.
   b. Requires Commissioner make public in writing the specific findings and conclusions upon which that determination is based.

A Summary of the Case for the Sale of the State of Alaska's North Cook Inlet "Royalty Gas" to the Alaska Pipeline Company ("Anchorage Natural Gas")

Prepared for presentation to the
Resources Committees of the
Ninth Alaska State Legislature

May, 1976

AGO 801720

In an effort to meet an immediate need for additional gas reserves for the North Kenai area and to assist in maintaining the long term reserves required to meet the on-going and ever increasing demands of its entire service area, Alaska Pipeline Company ("APC") has reached agreement with the State of Alaska on the terms of a contract whereby APC would purchase the State's one-eighth (1/8th) royalty share of the North Cook Inlet Field. The majority of the gas so obtained would be used to satisfy the needs of the North Kenai area while the balance would be available for use throughout the service area.

Essentially the contract calls for APC to take the gas at the platform on a when and as available basis with no operational burden or financial loss to the State. The pricing features of the contract are such as to prevent any subsidization of Cook Inlet gas and power consumers by the State.

The need for additional reserves for service to the North Kenai area is immediate and is a consequence of the actual exhaustion of the reserves under contract for that area. An extension of the contract for one year has been obtained but with the gas to be taken from "Anchorage" reserves. While such an extension serves well to meet an immediate need, dependance on further such extensions is unwise as it accelerates

"Anchorage" reserve depletion while at the same time it affects deliverability and precludes long range company and customer planning.

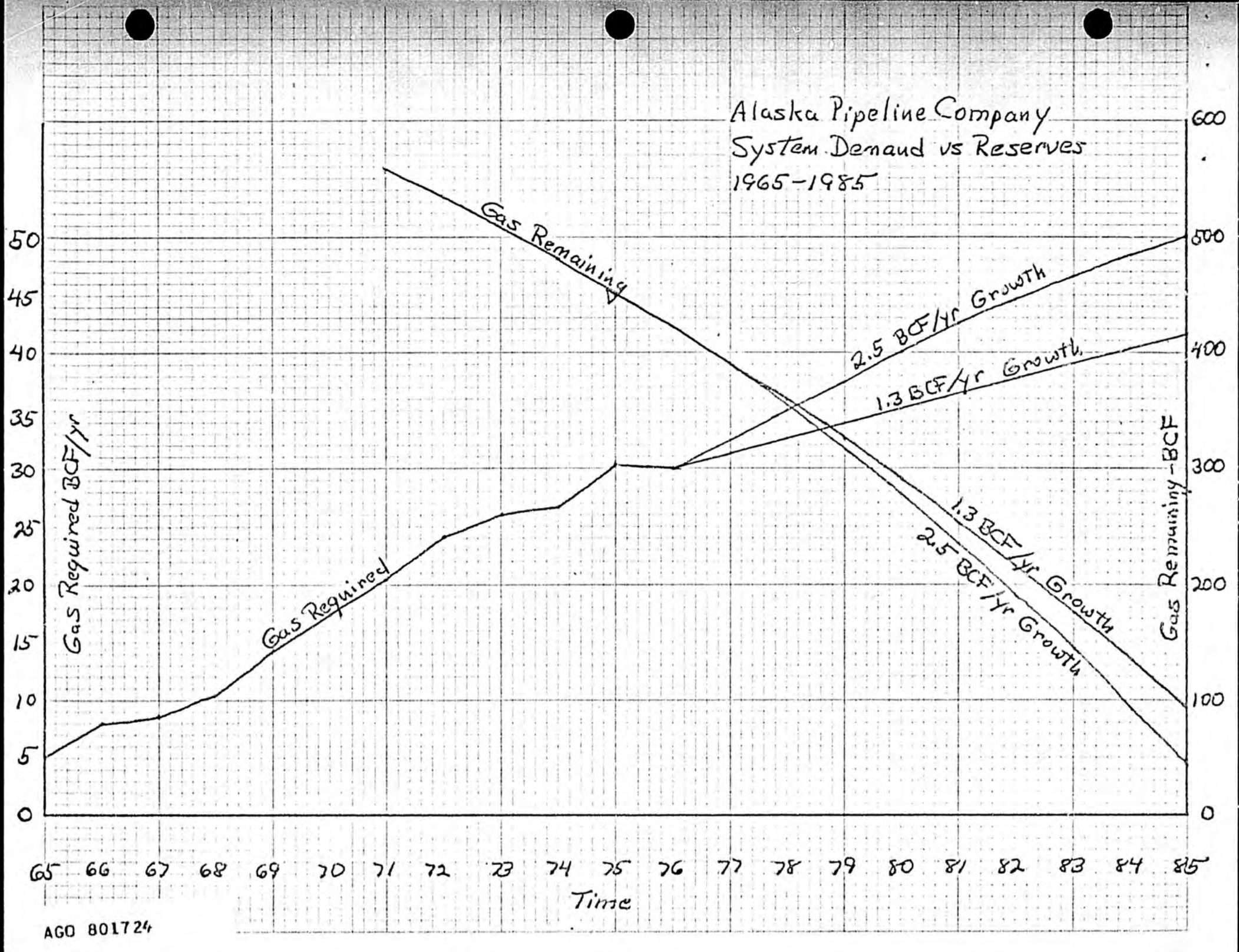
The interrelation of usage and reserve life in a growing market is quite fluid, sometimes misleading and always to an extent subjective. The attached chart provides a graphic presentation of the situation as presently viewed. The lower growth rate assumed is quite conservative and represents the lowest probable condition while the higher growth rate approximates our historical growth and is considered to be realistic. In either case it is evident that a need for additional reserves exists.

Recognizing the need for more reserves, APC had earlier contacted several producers regarding this matter of obtaining reserve commitments. Such negotiations are time consuming and at times frustrating (as can be attested to by others searching for reserve commitments in the same region) and as yet have not been fruitful. In addition, APC has commenced an exploration program on its leases in the Susitna River area but this, too, has not yet been successful.

While APC will continue to explore for gas finds of its own and to negotiate for the commitment of other reserves as they may become available, APC does believe that this contract, and the gas and reserve life that it represents, is essential to the well being of the entire Cook

Inlet area and strongly urges that favorable and timely legislative action be taken.

AGO 801723


Alaska Pipeline Company
System Demand vs Reserves
1965-1985
Gas Remaining
2.5 BCF/yr Growth
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1.3 BCF/yr Growth
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AGO 801724

RECEIVED
MAY 05 1976
ALASKA ROYALTY
OIL & GAS BOARD

Introduced: 5/4/76
Referred: Resources and Finance

IN THE HOUSE

BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

HOUSE CONCURRENT RESOLUTION NO. 142

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINTH LEGISLATURE - SECOND SESSION

Relating to the taking of state-owned royalty oil or gas in-kind and its disposal by sale.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the legislature by enactment of the Alaska Royalty Oil and Gas Development Board statute, AS 38.06. et seq., has established a clear policy of favoring the taking of state-owned royalty oil or gas in-kind and making that royalty available for in-state uses; and

WHEREAS the State of Alaska presently receives a one-eighth royalty on gas produced from the North Cook Inlet Gas Field in value, but has the right to receive this royalty in-kind; and

WHEREAS the commissioner of natural resources has entered into a contract for the sale and purchase of state-owned royalty gas from the North Cook Inlet Gas Field with Alaska Pipeline Company, an Alaskan corporation which sells natural gas in the Anchorage and North Kenai Road areas; and

WHEREAS the contract between the State of Alaska and Alaska Pipeline Company requires as a condition precedent to its becoming effective approval by a majority of each house of the Legislature;

BE IT RESOLVED by the Alaska State Legislature that approval of Alaska Royalty Gas Sale No. 76-1, the contract for the sale of state royalty gas from the North Cook Inlet Gas Field to Alaska Pipeline Company, is hereby approved.

AGO 801725

STATE of ALASKA

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES
OFFICE OF THE COMMISSIONER

TO: The Honorable Jay S. Hammond
Office of the Governor

DATE : April 30, 1976

FROM: Guy R. Martin
Commissioner

SUBJECT: Transmittal of Alaska Royalty Gas Sale No. 76-1

Attached are letters to the President of the Senate and Speaker of the House for your signature. Accompanying each letter is a copy of the subject contract, necessary written approvals by the Alaska Royalty Oil and Gas Development Advisory Board findings and conclusions by the Commissioner of Natural Resources supporting the decision to hold a non-competitive sale.

The letter and attachments should be sent to each House for their approval by concurrent resolution.

PLEASE NOTE: Mag Cards are attached for your use in case there are any changes made. Please return the mag cards with our information copy. Thanks.

April 30, 1976

The Honorable Mike Bradner
Speaker of the House
Alaska State Legislature
Pouch V
Juneau, Alaska 99811

Transmittal of Proposed
Alaska Royalty Gas Sale No. 76-1

Dear Mr. Speaker:

Attached is Alaska Royalty Gas Sale Contract No. 76-1 providing for a sale of State royalty gas from the North Cook Inlet Gas Field to Alaska Pipeline Company pursuant to AS 38.96 et seq., AS 38.05.182-183, and 11AAC28.005-.900. Also attached are all necessary waivers or consents related to this action and required under the law. The contract and all necessary related actions have been approved by the Alaska Royalty Oil and Gas Development Advisory Board pursuant to the above statutes and regulations. Other information pertinent to the proposed sale is also attached, with the intention of supplying you with an adequate record on this matter.

Alaska Pipeline Company, and its subsidiary Alaska Gas and Service Company, supply natural gas to the Anchorage area and a portion of the North Kenai peninsula known as the North Kenai road area. Increased use of natural gas due to growth in both areas is diminishing the gas reserves dedicated to Alaska Pipeline Company faster than anticipated. The company estimates that the contract amount for the North Kenai road area will be exhausted by May of this year and has executed a one year contract with their present supplier to extend their service.

Natural gas from the North Cook Inlet Gas Field, operated by Phillips Petroleum Company, is transported from the offshore platform to the LNG plant in the Nikiski area served by the North Kenai road and liquified for export to Japan.

The proposed contract provides that the State of Alaska will take its royalty share of the North Cook Inlet Gas Field production in kind rather than in value, and sell this gas to Alaska Pipeline Company at the same price that the State would otherwise receive from Phillips Petroleum Company. The amount of gas sold would average 15 to 16 million cubic feet per day and total about 41 billion cubic feet over the term of the royalty sales contract, which would expire June 1, 1984, coincidentally with the expiration of the present Phillips contract for export to Japan. Transportation or exchange provisions will be arranged by Alaska Pipeline Company, as will all necessary regulatory clearances.

The present peak gas demands along the North Kenai road can be as high as 10 million cubic feet per day. Gas excess to these needs can be used to augment the gas supply to Anchorage and extend the life of those reserves.

The total contract amount represents about one and one-half year's supply of gas at Anchorage's present rate of use, and about one year's production of the North Cook Inlet Gas Field.

The Commissioner of Natural Resources and the Alaska Royalty Oil and Gas Development Advisory Board recognize that the proposed sale of royalty gas will somewhat shorten the productive life of the North Cook Inlet Gas Field by approximately one year. Since the LNG contract requires delivery of a specified amount each year it will be necessary to increase the daily production of the field by the amount of the royalty gas withdrawn from the LNG plant. On balance, however, the sale of this royalty gas to supply the North Kenai road area and Anchorage is deemed to be in the best interest of the State, as it returns State royalty gas from foreign export to Alaska consumers at a price which assures all Alaskans a fair return for their resources.

I have, at various times, expressed the belief that section 55 of the Royalty Board Statute (which requires legislative approval by concurrent resolution of any sale of surplus royalty gas) is unconstitutional. The Administration believes that this requirement raises a substantial constitutional question and has concluded that in the future appropriate action will be necessary either by the Legislature to amend the Royalty Board Statute or by the courts to decide the constitutionality of

section 55. Notwithstanding such doubts concerning the constitutionality of this provision, the contract is being submitted to the Legislature for approval. Two reasons support this submission. First, early in this session, the Commissioner of Natural Resources advised the Legislature of his intent as a policy matter to carry out all the requirements of the Royalty Board Statute. I believe it would be less than forthright to pursue any other course for a sale during the closing days of the legislative session. Second, although this sale involves a relatively small quantity of gas, I am anxious to see it consummated at the earliest possible time as it will directly and immediately benefit gas consumers in the Anchorage and North Kenai areas. For that reason, it is undesirable that this contract become entangled in litigation which might extend over a lengthy period of time.

To avoid the choice of either appearing to acquiesce in the requirement of legislative approval or undertaking a perhaps unnecessary confrontation, a term has been included within the contract which provides that the contract will not become effective until approved by concurrent resolution passed by a majority of each house of the Legislature. The Administration always has the right to seek the advice and counsel of the Legislature and I have in this contract sought to make legislative approval a condition precedent to the contract becoming effective. I am submitting this contract to you for your approval pursuant to that term. However, in doing so, I wish to make clear beyond preadventure that my action should not be construed as either approval of or acquiescence in section 55 of the Royalty Board Statute and that I do not feel personally or legally obligated to submit future contracts for the sale of royalty oil or gas to the Legislature for approval by concurrent resolution.

You are aware that this is the first royalty sale contract prepared under the existing Statute, and of the first of its kind in the Nation. The Commissioner of Natural Resources, who is the official responsible for the agreement, is prepared to supply all necessary additional information to assist you in your consideration of this sale contract. Thank you for your consideration.

Sincerely,

Jay S. Hammond
Governor

Attachment

Natural Resources/WCF/dk/tdg

CC: [illegible]

Findings and Conclusions for Non-Competitive Sale

Pursuant to AS.38.05.183 and AS.38.06 the findings and conclusions which form the basis for the decision that the sale of North Cook Inlet Gas Field royalty gas to Alaska Pipeline Company should be non-competitive sale are summarized.

1. Alaska Pipeline Company formerly Anchorage Natural Gas Company, is in need of additional natural gas supply. The present contract of 10 billion cubic feet to supply the North Kenai road area will be exhausted during the first half of 1976. Alaska Pipeline has executed an agreement recently with their supplier which enables them to use gas from the Anchorage contract reserves to supply the North Kenai area for one additional year. Projections of the present growth rate of Anchorage and use of natural gas indicate that the Anchorage contract dedicated gas supply could be exhausted several years before the contract termination at the end of 1992.

2. The proposed sale amount of royalty gas is sufficient to meet the needs of the North Kenai area for the term of the agreement. Present use of the North Kenai area is 10 million cubic feet per day. About 90% of this gas is used by the Bernice Lake electric generating plant of Chugach Electric Association. The difference between winter and summer loads is small. The North Cook Inlet Gas Field royalty gas share averages 15 to 16 million cubic feet per day. Gas in excess to the North Kenai area demand can be used to augment the Anchorage contract gas supply. The total volume of gas which would be sold under the proposed agreement is approximately 40 to 41 billion cubic feet.

3. North Cook Inlet Gas Field gas furnishes 70% of the gas supply of the Nikiski LNG plant, the remaining 30% is supplied by Marathon from the Kenai Gas Field. The LNG is shipped to Japan in cryogenic tankers and revaporized for use by Tokyo Gas and Tokyo Electric. At this time, the State is taking its royalty share in value and this gas brings the greatest return to the State of any royalty gas.

4. Proposed sale of this royalty gas will not diminish State revenue. Alaska Pipeline has agreed to pay the State the same price that the State otherwise would have received

from Phillips. Price terms in the proposed agreement are based on Phillips prices plus an agreement to pay a price equal to the highest price paid in Upper Cook Inlet for gas of similar quality and similar conditions of delivery.

5. The proposed action may reduce the productive life of the field equivalent to one year at the present rate of production. The total amount of gas sold under the agreement will be about 40 to 41 billion cubic feet per year. The present LNG contract dedicated reserves are 647,543 million cubic feet. Estimated original recoverable reserves were 1,500,000 million cubic feet. The estimated remaining gas reserves not committed to contract are about 834 billion cubic feet. The proposed sale involves about 5% of the remaining uncommitted reserves. Because the LNG sale contract requires delivery of 50,750 million cubic feet of gas per year to Tokyo, it will be necessary for Phillips to increase the field production by the amount withdrawn for royalty sale. While this increased production will shorten the producing life of the field, the amount of decrease is small and amounts to less than one year's production.

6. During the period of review of Alaska Pipeline Company's application for purchase of royalty gas applications were also made by Homer Electric Association, Pacific Alaska LNG and Phillips Petroleum.

Homer Electric wished to buy the Bernice Lake generating facility from Chugach Electric and wanted to use the North Cook Inlet Gas Field royalty gas to supply the generator. This would be the same use proposed by Alaska Pipeline. Homer Electric subsequently advised the Alaska Royalty Oil and Gas Development Board that HEA had made satisfactory arrangements with the City of Kenai for a gas supply in the event it would be needed.

Pacific Alaska LNG made a statement that they would be interested in bidding for the North Cook Inlet royalty gas if it were offered in a competitive bid sale.

Later, Pacific Alaska advised the Board both by mail and in person that they were not making application for the North Cook Inlet royalty gas but rather a general statement applicable to possible future sales of other royalty gas.

Phillips Petroleum made a firm offer to purchase the royalty gas with an increase in price of five cents per thousand cubic feet (MCF) the first year, a similar increase the second year, and an annual escalation of two cents per MCF thereafter for the life of the present contract.

The withdrawals of Homer Electric and Pacific Alaska LNG left Phillips Petroleum as the only viable alternate to Alaska Pipeline's application.

CONCLUSION:

The decision to hold a negotiated sale rather than a competitive sale was based on several factors: end use, price to consumers, and future gas supply for Alaska.

The export of LNG to Japan has created a substantial market for Alaska's natural gas converting a non-revenue producing resource into a valuable asset with substantial revenues to the State.

The exported LNG produces about 75% of the State revenue from natural gas. While there was a reluctance to alter the use of the royalty gas and possibly necessitate additional costs to the LNG project, the use of the gas by the Kenai and Anchorage consumers was deemed to be a higher and better use.

Alaska Pipeline agreed to pay the State the same price the State otherwise would have received for the gas thereby maintaining the same revenue from the gas. While a competitive sale might have resulted in more revenue for the State it would also result in the gas being exported from the State and not available for Alaskan use. Alternately, if an Alaskan company was the successful high bidder it likely would set a new high price to the Alaskan consumer.

The present sale represents a balance of public values regarding this series of issues. The proposed non-competitive sale of North Cook Inlet Gas Field royalty gas appears to be in the best interest of the State as a whole and of the Kenai and Anchorage area gas consumers more directly. There is no loss of revenue to the State; the gas sale will be the gas supply for the North Kenai road area and add to the Anchorage area gas reserves; the slight loss of productive life of the North Cook Inlet Gas Field is offset by the continued service to the Alaskan gas consumers.

AGO 801732

Approval to Reject Bids

The Alaska Royalty Oil and Gas Development Advisory Board approves rejections of all bids or applications for the royalty gas from the North Cook Inlet gas field except that of Alaska Pipeline Company as provided for in AS.38.06.050(b)

Date April 26, 1976

Approved	Disapprove

AGO 801733

Approval of North Cook Inlet Field

Royalty Gas Purchase and Sale Agreement

The Alaska Royalty Oil and Gas Development Advisory Board approves the Gas Purchase and Sale Agreement for the sale of North Cook Inlet Field royalty gas to the Alaska Pipeline Company as provided for in AS 38.05.183 and AS 38.06.050.

Date April 26, 1976

APPROVED	Disapproved

Approval to Waive Competitive Bidding

The Alaska Royalty Oil and Gas Development Advisory Board approves the waiver of competitive bidding by the Commissioner of Natural Resources in the sale of North Cook Inlet royalty gas to Alaska Pipeline as provided for in AS.38.05.183(a) and AS.38.06.050(c).

Date April 26, 1976

Approved

Disapproved

B34

TELEGRAM

ACA ALASKA COMMUNICATIONS, INC.
PHONE: 586-6440
JUNEAU, ALASKA 99801

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1-034980C089 03/29/76

TWX PAC LGHT LSA

215 LOS ANGELES, CA MARCH 29, 1976

PMS MR. GUY MARTIN, CHAIRMAN

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

POUCH M

JUNEAU, ALASKA 99801

7580

RECEIVED
MAR 30 1976
ALASKA ROYALTY
OIL & GAS BOARD

WITH REFERENCE TO THE LETTER FROM PACIFIC ALASKA LNG COMPANY TO MR. GUY R. MARTIN, COMMISSIONER OF NATURAL RESOURCES, DATED MARCH 5, 1976. OUR OFFER TO BID ON THE PURCHASE OF THE STATES ROYALTY SHARE OF GAS IN THE NORTH COOK INLET AREA WAS LIMITED ONLY TO THOSE FIELDS IN THAT GENERAL AREA IN WHICH WE CURRENTLY HAVE THE RIGHT TO PURCHASE GAS OR MAY IN THE FUTURE HAVE THE RIGHT TO PURCHASE GAS. WE HAVE NO INTEREST IN BIDDING ON THE PURCHASE OF ANY STATE ROYALTY GAS PRODUCED FROM THE "NORTH COOK INLET FIELD"

PACIFIC ALASKA LNG COMPANY

P. VER PLANCK

1956 EST

AGO 801736

PACIFIC ALASKA LNG COMPANY

720 West Eighth Street
Los Angeles, California
Mailing address:
P.O. Box 54288 Terminal Annex
Los Angeles, Calif. 90054

March 5, 1976

RECEIVED
MAR 09 1976
ALASKA DIVISION
OIL & GAS BOARD

Mr. Guy R. Martin, Chairman
State of Alaska
Department of Natural Resources
Office of the Commissioner
Pouch M
Juneau, Alaska 99801

Dear Mr. Martin:

As you know, Pacific Alaska LNG Company for some time now has been carefully following developments relating to the state of Alaska's position on the disposition of the royalty gas in the Cook Inlet Area of the state that it is entitled to take in kind pursuant to AS § 38.05.182. Our interest stems from our proposal to purchase natural gas in the Cook Inlet Area of the state of Alaska for liquefaction, transportation as LNG, regasification and delivery to markets in the state of California.

The project proposed by our company contemplates the creation of a market for natural gas produced in the southern part of the state of Alaska, the building of a cross-inlet natural gas pipeline to open the northwest Cook Inlet to natural gas production, the construction of facilities to liquefy natural gas on the eastern side of the Inlet and the creation of new jobs within the state.

At this time Pacific Alaska has commitments for natural gas reserves in the Beluga River, Ivan River, Lewis River, Beaver Creek, McArthur River and Trading Bay fields. It is anticipated that Pacific Alaska will obtain commitments from additional fields in the north Cook Inlet Area and exploratory efforts are expected to discover new fields. However, in order to make Pacific Alaska's project economically viable, it is imperative that Pacific Alaska retain its commitments on the portion of the gas attributable to the state's royalty interest share in those fields.

It has been the position of Pacific Alaska not to get involved in the royalty issue in the Cook Inlet unless the state of Alaska indicated that it was about to make the determination that the best interest of the state dictated that Cook Inlet royalty gas should be taken in kind. We have now been made aware that the state is actively considering the sale of such royalty gas from certain Cook Inlet fields other than those mentioned

Harvey A. Proctor
President

AGO 801737

above, and Pacific Alaska is compelled at this time to take action to preserve its project (currently on file with the United States Federal Power Commission in Docket No. CP75-140).

In that the state is considering the sale of royalty gas from certain fields in the Cook Inlet, in the event that the Commissioner makes the determination that it is in the best interest of the state to take Cook Inlet royalty gas in kind, Pacific Alaska is prepared to make an offer to the state regarding the purchase of such royalty gas so taken. To this end, Pacific Alaska respectfully requests notice of any actions of the Alaska Royalty Oil and Gas Development Advisory Board with respect to this matter.

Thank you for your consideration.

Very truly yours,

H. A. Proctor, President

PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA 74004 918 661-6600

RECEIVED
NATURAL RESOURCES GROUP
Minerals Division
MAR 09 1975
ALASKA ROYALTY
OIL & GAS BOARD

March 5, 1976

State Royalty Gas
North Cook Inlet Field

File: 1-Ho-111-76-G&GL

RECEIVED
MAR 1976
Department of
Natural Resources

Commissioner Guy Martin, Chairman
Alaska Royalty Oil and Gas Development
Advisory Board
c/o Department of Natural Resources
Pouch M
Juneau, AK 99801

Dear Mr. Martin:

We have become aware that since the Board's decision of December 10, 1975, to take the State's royalty share of the gas in the North Cook Inlet Field and sell it to Anchorage Natural Gas, other parties have indicated a desire to purchase this gas. Assuming that the State does elect to take its royalty in kind under the lease, Phillips would be interested in an opportunity to purchase such gas. Phillips submits the following proposal to purchase all of the royalty gas from the North Cook Inlet Field.

1. Volume: The State will sell and Phillips will purchase all of the royalty gas owned by the State of Alaska as produced from the North Cook Inlet Field each day.

2. Price: 50.25¢ per million Btu until July 1, 1976;
55.5¢ per million Btu from July 1, 1976 to July 1, 1977;
60.0¢ per million Btu from July 1, 1977 to July 1, 1978.

For the yearly period commencing July 1, 1978, and each yearly period thereafter, the price will increase 2¢ per million Btu.

3. Term: Until June 1, 1984.

4. Delivery Point: At the wellhead on the platform in the North Cook Inlet Field.

5. Delivery Pressure: The pressure available at the wellhead.

The above proposal is subject to the completion of a mutually agreeable contract between the State of Alaska and Phillips. This offer is open until July 1, 1976.

If the above proposal is of interest to you, we will be happy to meet with you or your representatives and negotiate the details of the formal agreement.

Very truly yours,

John Horn, Manager
Gas and LNG Sales Branch

JH:bla

Draft by APC of April 9, 1976
With comments by ____?

AGREEMENT FOR THE SALE OF NORTH COOK INLET ROYALTY GAS
FROM THE STATE OF ALASKA
TO ALASKA PIPELINE COMPANY

APR 12 19
OIL & GAS

This memorandum ("Agreement") reflects the intent of the State of Alaska ("the State") and Alaska Pipeline Company ("APC") regarding APC's purchase of the State's 1/8th (one-eighth) royalty share of natural gas produced at the North Cook Inlet Gas Field, which is operated by Phillips Petroleum Company ("Phillips").

WHEREAS, Union Oil Company of California ("Union") as Operator of the Kenai Gas Field and the gas transmission line from the Kenai Gas Field to the North Kenai Road now supplies APC's total requirements for natural gas at the Kenai Gas Field and at three (3) pipeline taps on the North Kenai Road; and

WHEREAS, APC has an early and urgent need to purchase additional natural gas for its customers in the vicinity of the North Kenai Road, and has applied to the State to acquire the State's 1/8th royalty share of gas produced by Phillips at the North Cook Inlet Gas Field to the extent any portion or all of such royalty gas may be available to APC without causing additional investment by Phillips, and

WHEREAS, the royalty gas and the Kenai Field Gas are sufficiently similar that exchange rather than literal transfer of the royalty gas may be of advantage to all parties concerned including APC's ultimate gas consumers and such exchange may be practical because of the Kenai Gas Field's interconnection with the North Cook Inlet Gas Field which has allowed exchanges to be made from time to time in the past, and

WHEREAS, APC considers that the merit of proceeding to purchase this royalty gas is sufficient to justify its installing the necessary pipeline, compressors, and connections to facilitate the literal transfer of this gas into APC's existing pipeline as an alternative to exchanging in the event such exchanging is found to be impractical either before or after the purchase has begun, and

WHEREAS, the proposed sale of the royalty gas is seen to be in the public interest of the citizens of Alaska and the gas consumers served by APC (as evidenced by various statements which are of public record),

NOW

however that such price as determined each June 1, to be effective on deliveries from June 1 through May 31 of the following year, shall not be less than the highest price paid for gas produced in the area designated as Exhibit A hereof during the twelve preceding months at wellhead for gas of comparable quality and at comparable terms and conditions of delivery.

Said payments shall be made on or before the 20th day of the month following the month in which the purchases occur.

OK

2. The State and APC agree that the quantity and quality of gas purchased by APC hereunder shall be at the sole determination of Phillips, provided that APC shall be entitled to receive, ~~at a mutually agreeable point of delivery at or near the Phillips liquefaction plant,~~ on the platform gas of the quality and at the pressure existing in Phillips' pipeline, and in daily volume of one-eighth (1/8th) the total volume delivered by Phillips during the preceding day, except that by mutual agreement other delivery volumes may be in effect from time to time if necessary and desirable to suit the mutual interests of Phillips and APC.

Point of Delivery Between APC & PPCo or APC & State? Point of delivery should be platform.

3. This Agreement shall not serve to predispose APC's opportunity to develop an exchange agreement with Union, it being agreed that such an exchange agreement may be desirable and preferable to APC's installing of the pipeline and compressors which otherwise would be required.

OK w/ change to Pipeline

4. This Agreement shall not be used to require Phillips to submit to any form of regulation by the Alaska Public Utilities Commission or by any other administrative or legislative body or agency, whether federal, or state, or other which would not be applicable if this Agreement did not exist. In the event of such regulation being asserted and implemented, then this Agreement shall terminate and become null and void.

OK jurisdiction

5. This Agreement shall not be used to require Phillips to make additional investment except on terms to which Phillips and APC may agree, it being understood that in the event additional investment by Phillips should become necessary in order for Phillips to meet its contractual obligations as to production and transportation of gas from its North Cook Inlet Gas Field to its liquefaction plant and in the further event that APC is unwilling or unable to participate in or to reimburse Phillips as reasonably necessary for that investment, then this Agreement shall terminate and become null and void, or in the alternative at its option, APC shall agree to reduce deliveries hereunder as necessary to enable Phillips to meet its contractual obligations without making such additional investment.

Additional investments terms to be negotiated between APC and Phillips

AGO 801742

6. APC shall install and operate, at its cost, all gas metering and compression equipment required hereunder, if any, on land provided by the State (or Phillips) ~~without charge to APC~~. If such metering equipment is installed and operated by APC, it shall conform to recognized industry standards and shall be available for inspection and verification by the State (or Phillips) at all reasonable times. In the event APC develops an exchange agreement such that no metering equipment is required hereunder, then APC and the State agree to accept the metering performed by Phillips (and by Union or others), subject to APC's right of inspection and verification at all reasonable times.

7. The State shall not be deemed to be in control of gas taken by APC hereunder whether by exchange or otherwise, and APC shall not be deemed to be in control of gas it receives except from the downstream flange of its metering equipment, if any is installed.

8. It is the intent of this Agreement that APC shall receive all of the royalty gas produced by Phillips during the term hereof, each day of such production. Failure of APC to receive such gas each day, except with the consent of Phillips and the State or by force majeure, shall require APC to forfeit its right to subsequent receipt of that gas not taken. Recurring or continuing failure of APC to receive such gas, without such consent and not due to force majeure or other reasonable cause, or failure of APC to make timely payment therefor, may serve as the basis for termination of this Agreement by the State at its option.

9. This contract shall become binding on APC the day of its approval by the legislature and shall terminate on June 1, 1984 or earlier as provided herein, except that it may be extended indefinitely by mutual agreement. APC shall not be required to take delivery of gas hereunder prior to one year after the effective date hereof if an agreement is reached for exchange as contemplated in paragraphs (1) and (3) hereof, or 18 months from the effective date hereof if an exchange agreement is not obtained and it thus becomes necessary for APC to install a pipeline and compressors in order to receive gas hereunder.

This Agreement was executed on _____, 1976.

for the State of Alaska

by _____

for Alaska Pipeline Company

by _____

AGO 801743

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 Anchorage, Alaska 99502 / Phone (907) 277-5551
Telex 25-187

April 9, 1976

RECEIVED
APR 12 1976
Department of
Natural Resources

Mr. Bill Fackler, Executive Director
State of Alaska Oil and Gas Royalty Board
Department of Natural Resources
Pouch M
Juneau, AK 99811

Dear Bill:

I talked to Commissioner Martin this morning and he recommended that we should proceed with a contract draft as soon as possible. The enclosed draft should be a starting point at least, and I have tried to keep it as simple as I could.

1977

Apparently we may need until August of next year to get compressors delivered and installed, and I would hope that start-up could be so scheduled unless Union-Marathon should agree to begin a temporary exchange operation after May 1, 1977 when the present contract is finished, or agree to a continuing exchange so that the pipeline and compressors would not be required. Alternately, of course, if Phillips would agree for us to take only the royalty needed on the North Kenai Road, and supply us during any plant downtime, we would not need a pipeline.

I am forwarding to Phillips, and Union and Marathon, a copy of this letter and the draft in order to get their reaction as soon as possible. I do not infer that the draft carries any blessing by the State as yet, however. Please advise us as to whom we should contact next to review the draft, as soon as you have retained counsel for that purpose.

Cordially,

Dale Teel

Dale Teel
President

cc: Board members 1/13 AK

DT:jdh

Enclosure

RECEIVED
APR 12 1975
ALASKA ROYALTY
OIL & GAS BOARD

cc: Mr. John Horn, Phillips
Mr. Bart Emery, Marathon
Mr. Larry Bradford, Union
Alaska Public Utilities Commission

AGO 801744

AGREEMENT FOR THE SALE OF NORTH COOK INLET ROYALTY GAS
FROM THE STATE OF ALASKA
TO ALASKA PIPELINE COMPANY

APR 12 19
OIL & GAS BO

This memorandum ("Agreement") reflects the intent of the State of Alaska ("the State") and Alaska Pipeline Company ("APC") regarding APC's purchase of the State's 1/8th (one-eighth) royalty share of natural gas produced at the North Cook Inlet Gas Field, which is operated by Phillips Petroleum Company ("Phillips").

WHEREAS, Union Oil Company of California ("Union") as Operator of the Kenai Gas Field and the gas transmission line from the Kenai Gas Field to the North Kenai Road now supplies APC's total requirements for natural gas at the Kenai Gas Field and at three (3) pipeline taps on the North Kenai Road;

WHEREAS, APC has an early and urgent need to purchase additional natural gas for its customers in the vicinity of the North Kenai Road, and has applied to the State to acquire the State's 1/8th royalty share of gas produced by Phillips at the North Cook Inlet Gas Field to the extent any portion or all of such royalty gas may be available to APC without causing additional investment by Phillips, and

WHEREAS, the royalty gas and the Kenai Field Gas are sufficiently similar that exchange rather than literal transfer of the royalty gas may be of advantage to all parties concerned including APC's ultimate gas consumers and such exchange may be practical because of the Kenai Gas Field's interconnection with the North Cook Inlet Gas Field which has allowed exchanges to be made from time to time in the past, and

WHEREAS, APC considers that the merit of proceeding to purchase this royalty gas is sufficient to justify its installing the necessary pipeline, compressors, and connections to facilitate the literal transfer of this gas into APC's existing pipeline as an alternative to exchanging in the event such exchanging is found to be impractical either before or after the purchase has begun, and

WHEREAS, the proposed sale of the royalty gas is seen to be in the public interest of the citizens of Alaska and the gas consumers served by APC (as evidenced by various statements which are of public record),

NOW THEREFORE, the State and APC agree as follows:

1. The State agrees that it will give notice to Phillips that it elects to take its royalty gas in kind within one year of the date of such notice (but not sooner than six months following such notice except at the consent of Phillips), upon APC's completion of negotiations for exchanging or APC's completion of its pipeline connection in the alternative. Whether taken by exchanging or by literal transfer, APC will pay to the State, for remittance to Phillips, an amount calculated to cover Phillips' reasonable costs for dehydrating and transporting the gas from its offshore platform at the North Cook Inlet Gas Field to its liquefaction plant on the North Kenai Road near Kenai, Alaska. In addition, APC will pay to the State the wellhead price in effect as wellhead value for calculation of severance taxes payable by Phillips to the State from year to year, amended as of June 1 of each year to June 1, 1984, provided

however that such price as determined each June 1, to be effective on deliveries from June 1 through May 31 of the following year, shall not be less than the highest price paid for gas produced in the area designated as Exhibit A hereof during the twelve preceding months at wellhead for gas of comparable quality and at comparable terms and conditions of delivery.

Said payments shall be made on or before the 20th day of the month following the month in which the purchases occur.

2. The State and APC agree that the quantity and quality of gas purchased by APC hereunder shall be at the sole determination of Phillips, provided that APC shall be entitled to receive, at a mutually agreeable point of delivery at or near the Phillips liquefaction plant, gas of the quality and at the pressure existing in Phillips' pipeline, and in daily volume of one-eighth (1/8th) the total volume delivered by Phillips during the preceding day, except that by mutual agreement other delivery volumes may be in effect from time to time if necessary and desirable to suit the mutual interests of Phillips and APC.

3. This Agreement shall not serve to predispose APC's opportunity to develop an exchange agreement with Union, it being agreed that such an exchange agreement may be desirable and preferable to APC's installing of the pipeline and compressors which otherwise would be required.

4. This Agreement shall not be used to require Phillips to submit to any form of regulation by the Alaska Public Utilities Commission or by any other administrative or legislative body or agency, whether federal, or state, or other which would not be applicable if this Agreement did not exist. In the event of such regulation being asserted and implemented, then this Agreement shall terminate and become null and void.

5. This Agreement shall not be used to require Phillips to make additional investment except on terms to which Phillips and APC may agree, it being understood that in the event additional investment by Phillips should become necessary in order for Phillips to meet its contractual obligations as to production and transportation of gas from its North Cook Inlet Gas Field to its liquefaction plant and in the further event that APC is unwilling or unable to participate in or to reimburse Phillips as reasonably necessary for that investment, then this Agreement shall terminate and become null and void, or in the alternative at its option, APC shall agree to reduce deliveries hereunder as necessary to enable Phillips to meet is contractual obligations without making such additional investment.

15. It is doubtful that the State could transfer the existing transport situation with Phillips to another party without Phillips consent. The State lease provides that when the Lessor elects to take its royalty in-kind, the Lessee shall deliver it free of charge on said land or at such place as Lessor and Lessee mutually agree upon. Further, the transport charge itself may be open to negotiation between Phillips and Alaska Pipeline.

16. The Phillips-Marathon contract with Tokyo Gas and Tokyo Electric expires June 1, 1984, unless extended. The State of Alaska North Cook Inlet royalty gas availability is dependent upon continued production from Phillips platform. At present, production from the North Cook Inlet gas field is not certain beyond June 1, 1984.

CONCLUSIONS

The growth of population and increased commercial activity of the Anchorage area and its environs served by Alaska Pipeline and its distribution affiliate Alaska Gas and Service is consuming the gas reserves of that system at a rate greater than originally anticipated. A source of additional gas reserves to that system could be made available from the State's royalty gas share of the production from the North Cook Inlet Unit gas field which is now being liquefied by the Phillips-Marathon LNG and exported to Japan. Alaska Pipeline has offered to take this gas as it becomes available through production for the LNG plant and pay the State the same price that the State would otherwise receive from Phillips for that gas. The sale is necessarily dependent on reasonable exchange or transportation arrangements being consummated between Phillips and Alaska Pipeline.

Under these circumstances it is in the best interest of the State of Alaska to take the North Cook Inlet Unit royalty gas in kind and sell the gas to Alaska Pipeline for use in the Cook Inlet area served by that system.

DECISION

Purusant to the authority vested in the Commissioner of the Department of Natural Resources, under AS 38.05.180-183 and AS 38.06.010-080, and under the Alaska Oil and Gas Leasing Regulations pusurant thereto, and with the concurrence of the Alaska Royalty Oil and Gas Development Advisory Board, I do hereby:

(a) determine that it is in the public interest to take the State of Alaska royalty share of gas production from the North Cook Inlet Unit gas field in-kind;

(b) determine that it is in the public interest to enter into a negotiated sale of the North Cook Inlet Unit gas field royalty gas to Alaska Pipeline.

Date:

_____

Commissioner DNR

Approved:

Alaska Royalty Oil & Gas Development Advisory Board

_____ Date:

_____

_____

_____

_____

_____

6. APC shall install and operate, at its cost, all gas metering and compression equipment required hereunder, if any, on land provided by the State (or Phillips) without charge to APC. If such metering equipment is installed and operated by APC, it shall conform to recognized industry standards and shall be available for inspection and verification by the State (or Phillips) at all reasonable times. In the event APC develops an exchange agreement such that no metering equipment is required hereunder, then APC and the State agree to accept the metering performed by Phillips (and by Union or others), subject to APC's right of inspection and verification at all reasonable times.

7. The State shall not be deemed to be in control of gas taken by APC hereunder whether by exchange or otherwise, and APC shall not be deemed to be in control of gas it receives except from the downstream flange of its metering equipment, if any is installed.

8. It is the intent of this Agreement that APC shall receive all of the royalty gas produced by Phillips during the term hereof, each day of such production. Failure of APC to receive such gas each day, except with the consent of Phillips and the State or by force majeure, shall require APC to forfeit its right to subsequent receipt of that gas not taken. Recurring or continuing failure of APC to receive such gas, without such consent and not due to force majeure or other reasonable cause, or failure of APC to make timely payment therefor, may serve as the basis for termination of this Agreement by the State at its option.

9. This contract shall become binding on APC the day of its approval by the legislature and shall terminate on June 1, 1984 or earlier as provided herein, except that it may be extended indefinitely by mutual agreement. APC shall not be required to take delivery of gas hereunder prior to one year after the effective date hereof if an agreement is reached for exchange as contemplated in paragraphs (1) and (3) hereof, or 18 months from the effective date hereof if an exchange agreement is not obtained and it thus becomes necessary for APC to install a pipeline and compressors in order to receive gas hereunder.

This Agreement was executed on _____, 1976.

for the State of Alaska

by _____

for Alaska Pipeline Company

by _____

AGO 801750

STATE of ALASKA

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES
Division of Oil and Gas

RECEIVED
APR 14 1975
ALASKA ROYALTY
OIL & GAS BOARD

TO: Guy R. Martin
Commissioner

Attn: Bill Fackler
Deputy Commissioner

DATE : April 9, 1976

FROM: O. K. Gilbreth, Jr.
Director

SUBJECT: North Cook Inlet Royalty Gas for 10 MMCF/D Take or Pay Contract for Alaska Pipeline Company

To furnish the Alaska Pipeline Company 10 MMCF/D it will be necessary to commit by individual leases since the entire field is unitized.

The most recent sales data for North Cook Inlet state royalty gas has averaged 16.007 MMCF/D for the past year. The following tabulation shows how this average equates back (Col. 5) to each Tract (Col. 1) and Lease No. (Col. 2) based on acreage Participation (Col. 4).

Column No. (1) Tract No.	(2) Lease No.	(3) No. Acres	(4) Percent Lse. Participation	(5) Royalty Gas - 12 month average - MMCF/D Tracks All	(6) Tracts 2,3,7	(7) Tracts 2,3,7,8
2	ADL-17589	4375.5	44.7324	7.1603	7.1603	7.1603
3	ADL-17590	640.0	6.5430	1.0473	1.0473	1.0473
7	ADL-18740	800.0	8.1787	1.3092	1.3092	1.3092
8	ADL-18741	640.0	6.5430	1.0473	-	1.0473
11	ADL-37831	3326.0	34.0029	5.4428	-	-
	Totals	9781.5	100.0000	16.0069	9.5168	10.5641
	Variations ± 10 MMCF/D				- .4832	+ .5641
	Peak Month - MMCF/D			19.409	11.5390	12.8090
	Variation ± 10 MMCF/D				+ 1.5390	+ 2.8090
	Low Month - MMCF/D			9.954	5.9180	6.5690
	Monthly variation ± 10 MMCF/D				- 4.0820	- 3.4310

Column 6 shows the summation of tracts 2,3 and 7 come the closest to a 10 MMCF/D total with 9.5168 MMCF/D for a variation difference of -483,200 CF/D. The summation of tracts 2,3,7 and 8 are also shown, but result in a slightly larger variation of +564,100 CF/D.

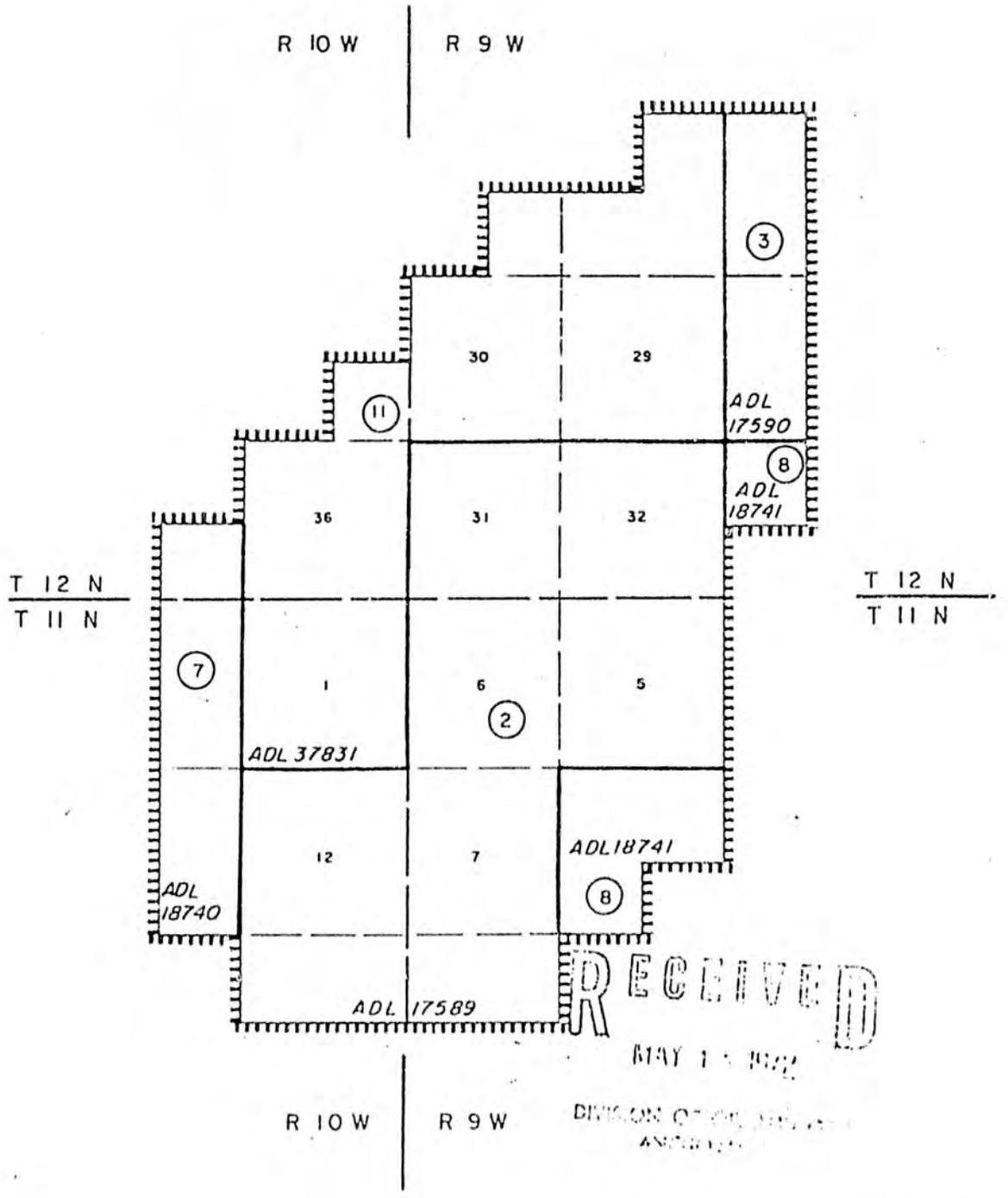
We have shown the maximum high and low variations which may be expected by inclusion of the Peak month and Low month data under Columns 5, 6 and 7. This shows that a monthly variation of from +1,539,000 CF/D to - 4,082,000 CF/D may result from tracts 2,3 and 7 (Col. 6).

A copy of Exhibit "A" from the unit agreement is attached for your convenience.

Attachment

AGO 801751

cc: All Board members 4-14-76 BK



RECEIVED
MAY 1 1972
DIVISION OF OIL AND GAS
ANCHORAGE

(Contracted 2-1-72)

ADL 17589
ADL 17590
ADL 18740
ADL 18741
ADL 37831

LEGEND

Unit Boundary
Tract Boundary
(3) Tract Number

EXHIBIT "A"
TO ACCOMPANY

CONTRACTED
NORTH COOK INLET
UNIT AGREEMENT

COOK INLET BASIN, ALASKA

Scale 1" = 1 mi Feb. '72

AGO 801752

Board memo 4-5-76 DK

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 Anchorage, Alaska 99502 / Phone (907) 277-5551
Telex 25-187

April 2, 1976

Mr. Bill Fackler, Executive Director
State of Alaska Oil and Gas Royalty Board
Department of Natural Resources
Pouch M
Juneau, AK 99811

RECEIVED APR 05 1975
RECEIVED APR - 5 1976
ALASKA ROYALTY OIL & GAS BOARD
Department of Natural Resources

Dear Bill:

This is written to furnish you with some background information relating to our past and present "flow through" situations and why we feel that the APUC actions have served to "inhibit" our search for new and probably higher priced non-royalty reserves.

Enclosure A contains our previous "flow through" provision while Enclosure B contains the one presently in effect.

A brief description of the sequence of events leading to the change is as follows:

December 15, 1974 - AGAS agreed to a gas price increase (19.5¢/MCF) to become effective July 1, 1975 in order to obtain gas in the quantities required by its customers. The APUC and major customers were notified in advance of completion of negotiations.

December 20, 1974 - The APUC ordered an investigation and public hearing on the tariff flow through provisions.

March 21, 1975 - AGAS filed new rates giving effect to the increased cost.

April 24, 1975 - The APUC rejected AGAS newly filed rates.

May 2, 1975 - AGAS notified suppliers to not proceed with any investment in workover and/or new wells required to meet its contractual commitments.

May 6, 1975 - The APUC ordered an investigation of the anticipatory breach of contract indicating that it might for good cause shown revoke AGAS certificate of public convenience and necessity.

May 8, 1975 - AGAS agreed to withdraw its tariff flow through provisions.

May 12, 1975 - The APUC accepted AGAS tariff filing of March 21, 1975 as an interim request for rate relief and set hearing date of June 19, 1975.

July 1, 1975 - The APUC granted an increase of 12.78¢/MCF.

July 9, 1975 - AGAS requested reconsideration of the July 1, 1975 order.

July 31, 1975 - The APUC denied AGAS request of July 9, 1975.

July 31, 1975 - AGAS filed proposed new cost of gas flow through tariff provisions to replace those withdrawn May 12, 1975.

August 28, 1975 - The APUC suspended the filing of July 31, 1975 and set hearing date of October 30, 1975.

December 17, 1975 - The APUC issued its order modifying the flow through provisions filed July 31, 1975.

AGAS subsequently petitioned for reconsideration of the order of December 17, 1975 and the APUC denied the petition. In addition to the above mentioned actions there have been a series of requests, hearings, and orders relating to AGAS further attempts to recoup its increased costs.

In concept, the idea that a full rate hearing for each fuel cost change is an appropriate means of consumer protection, appears valid. Our actual experience with the process indicates it is not. The following experiences have led us to this conclusion:

(1) Rate cases are expensive and time consuming processes. We have devoted an inappropriate amount of internal time and talent in our year long battle that began with the negotiated gas cost increase. We have spent approximately $320,000 on attorneys and other specialists in regulatory matters in attempting to recover costs incurred by us in good faith for the benefit of our customers. The benefit of hindsight indicates we made a timely and appropriate

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 / Anchorage, Alaska 99502

business decision, yet one that has been costly to the owners of the Company. Common sense tells us that a similar occurrence in the future could result in a new management team.

(2) The uncertain outcome of hearings before an appointed regulatory agency with a recent history of rapid change in composition and philosophy makes long term committments an extremely risky course of action.

A fuel cost flow through provision which would not require the company to assume the burden of proof in a full rate hearing for each fuel cost change would reduce the business risk to an acceptable level. Such provision would not prevent the Commission from ordering rate decreases in instances where the use of the provisions would result in an excessive profit to the utility.

Bill, I hope that this helps to explain our situation and to give you some insight into the constraints under which we labor as we strive to acquire additional reserves.

Very truly yours,

Harold

Harold F. Schmidt
Senior Vice President

HFS:jdh

Enclosures

ENCLOSURE A

PURCHASED GAS COST ADJUSTMENT CLAUSE
WITHDRAWN MAY 12, 1975

708 Purchased Gas Cost Adjustment - Company's rates are based on the current wellhead cost of a firm supply of natural gas at the gas field. In the event this price is increased or decreased, or taxes on such gas are increased or decreased, above the amount(s) payable on April 15, 1972, then the Company may, after appropriate notice to the Alaska Public Utilities Commission as required by AS 42.05.411, place into effect a like increase or decrease in the rate theretofore in effect. Such adjustment shall begin with bills rendered during the month subsequent to the effective date of the increase or decrease at wellhead.

PURCHASED GAS COST ADJUSTMENT CLAUSE
CURRENTLY IN EFFECT

708 Purchased Gas Cost Adjustment - The gas supply contracts existing on December 1, 1975, contain escalation clauses which result in periodic increases or decreases in the cost of purchased gas. Any increase in the cost of purchased gas to the Company under the escalation clauses that the Company becomes responsible for after July 1, 1976, may be passed on to the customers of the Company. Such an increase may be reflected in the rates paid by the customers for gas used by the customer after the date the Company is responsible for paying the increase. The increase, however, may not be charged to the customers of the Company unless the Company meets the conditions specified in Order No. 3 in Docket U-75-68. The Company may not flow through to its customers any increases in the cost of gas resulting from alterations, changes, or amendments of any part of the escalation clauses existing on December 1, 1975. The Company also may not flow through to its customers any other increase in the cost of gas except as specified in this Section and the Royalty Gas Section of this tariff. The increases flowed through to the customers pursuant to this section may not exceed 5¢/MCF per calendar year.

In the event the price which the Company must pay to purchase gas to serve the Company's customers is decreased the Company shall decrease its rates to its customers to fully reflect the entire decrease in the purchased gas cost.

Royalty Gas - The cost of gas purchased from the State is greater than the cost of gas purchased from other suppliers. The gas purchased from the State must be taken by the Company as produced. The Company must therefore distribute this gas to its customers when taken and it must be sold at a higher rate than the gas it now purchases from other suppliers. In order to insure a proper price of gas as a result of the commingling of the higher priced State gas and the lower priced gas from other suppliers the Company shall, month to month, increase or decrease the bills of customers to reflect the average cost per MCF of gas on an MCF basis which shall be computed as the product of the volume of gas purchased from the State each month multiplied by the price of that gas, plus the product of the volume of gas purchased from other suppliers during the month multiplied by the cost of this gas, and the sum of the products thus computed divided by the total volume of gas purchased. The flow through increases or decreases pursuant to this section of the tariff are subject to the conditions set forth in Order No. 3 of Docket U-75-68.

PROPOSAL

Alaska Pipeline Company and its distribution affiliate Alaska Gas and Service, Division of Alaska Interstate Company have requested the right to purchase the State of Alaska's royalty share (1/8 or 12 1/2%) of the North Cook Inlet gas field operated by Phillips Petroleum Company.

Alaska Pipeline Company supports their request with the following reasons.

1. Without this gas, Alaska Pipeline Company may not be able to continue serving the Bernice Lake power plant of Chugach Electric Association, or, if an alternate source of gas is found, the cost to Alaska Pipeline's customers is likely to be substantially more than the purchase of State royalty gas. This purchase will be of material benefit to Alaska Pipeline's residential and commercial gas customers and of even greater benefit to Chugach Electric Association and all its customers from Homer to Talkeetna. More than 50 percent of Alaska's population would be affected either as gas consumers or as power customers.

2. Alaska Pipeline is prepared to accept delivery of this gas immediately, on an "if and as available" basis, and at the same price the State would receive for this gas which is being liquefied and shipped to Japan.

Assuming that delivery to Alaska Pipeline can be made by exchange or displacement, there would be no necessity for capital expenditure

AGO 801758

for new pipelines or other facilities at present. If additional pipeline facilities or compression becomes necessary to maintain delivery, Alaska Pipeline would participate in such cost.

3. Alaska Pipeline recognizes that deliverability of North Cook Inlet royalty gas is dependent upon the Phillips Marathon LNG plant use. They have adequate deliverability under contract from the Kenai gas field so that deliverability from the North Cook Inlet gas field is not a problem and that differences in flow rate can be adjusted or compensated within their system.

Based on current production rates, Alaska Pipeline assumes that an average of 15,000 MCF per day of North Cook Inlet royalty gas would be available. This amounts to approximately 5.5 BCF per year or a total of 75 BCF over the 15 year period desired by Alaska Pipeline. 82.5

FINDINGS

1. Alaska Pipeline Company's Nikiski contract with Union-Marathon for 10 BCF expires May 1, 1977. This gas supply is used to service the North Kenai Road area including the Bernice Lake power plant owned by Chugach Electric Association which consumes approximately 90 percent of the total daily volume.

2. The increased load placed on the Bernice Lake generating facilities while waiting on repair of Chugach's submarine cable across Knik Arm and construction of an alternate land line to Wasilla greatly increased gas consumption which may result in

exhaustion of the Nikiski contract reserves in 1976 prior to the end of contract.

3. The need to replace the diminished gas reserves of the Nikiski contract and the desirability to augment the gas reserves of the Anchorage contract has led Alaska Pipeline to write Union, Marathon, Phillips and Shell seeking an additional 75 BCF of gas reserves over a 15 year period with no favorable results to date.

4. North Cook Inlet royalty gas is similar in composition and quality to Kenai field gas and therefore interchangeable with each other in any proposition. Gas from the two fields is blended as feedstock to the Phillips-Marathon LNG plant.

5. The necessary pipeline systems now exist to allow an exchange to be made so that Alaska Pipeline could receive the royalty gas equivalent at its Kenai gas field connection.

6. The deliverability of North Cook Inlet royalty gas is dependent on LNG plant use activity and therefore would not be a constant volume.

7. Alaska Pipeline's Anchorage contract provides sufficient deliverability and also is interruptible so that Alaska Pipeline has sufficient flexibility to receive North Cook Inlet royalty gas on an "if and as deliverable" basis.

8. Alaska Pipeline could construct a pipeline to deliver the royalty gas to its pipeline to Anchorage if the proposed gas exchange is not possible.

9. In the event that additional pipeline facilities or compression is necessary to maintain delivery of North Cook Inlet royalty gas, Alaska Pipeline would participate in such cost.

10. Alaska Pipeline proposes to pay to the State the same price which the State otherwise would have received from Phillips' for its use of North Cook Inlet royalty gas for the duration of the Phillips-Marathon LNG export to Japan and thereafter not less than

(1) the average price in effect during the last full year prior to termination of the export contract, and not less than

(2) the price in effect, from year to year, for gas purchased by Alaska Pipeline at the Kenai gas field (from Union-Marathon).

11. Alaska Pipeline proposes to purchase 1/8th of the production of the North Cook Inlet gas field, day by day and year by year. They understand that at current production rates, approximately 15,000 MCF/D, or 5.5 BCF/year, would be available. Alaska Pipeline would not require any particular amount by day, month, year, or in total; or could take a specified amount if the operators so desired.

12. Present production from the North Cook Inlet gas field is 44.2 BCF per year (1974). This gas is 70 percent of the feedstock for the Phillips-Marathon LNG plant which is contracted for export to Japan. To maintain the present contract requirements it will be necessary for Phillips to increase the gas production from the North Cook Inlet gas field by an amount equal to the present State royalty gas volume plus an amount to compensate for the additional royalty on the increased production. Thus the present annual production of 44.2 BCF would have to be increased to approximately 51 BCF per year to maintain contractual requirements plus the volume of royalty gas requested by Alaska Pipeline. The increased production would increase the State royalty volume to approximately 17,500 MCF per day.

Present information indicates the field reserves are adequate for the increased production but the field life will be shortened by the amount of the increased production of course.

13. The pipeline from the North Cook Inlet gas field platforms to the LNG plant is wholly owned by Phillips. The State of Alaska royalty value is received at the wellhead minus a transportation charge of 5.55 cents per MCF to the LNG plant. This point of taking means that the State receives royalty value on all gas used by Phillips for plant fuel, shrinkage, etc.

14. Transport of gas for Alaska Pipeline from the North Cook Inlet platform to shore might be construed as qualifying the pipeline for Alaska Public Utilities Commission jurisdiction. This situation would be objectionable to Phillips.

Price

Alaska Pipeline agrees to pay the State the same price which the State would have otherwise received from Phillips for export of the North Cook Inlet royalty gas to Japan for the duration of that export including any escalations in (±) price received by Phillips, and not less than the highest price paid in the area by any buyer to any seller of gas of similar quality.

Quantity & Deliverability

Alaska Pipeline recognizes that deliverability of North Cook Inlet gas field royalty gas is dependent upon Phillips-Marathon LNG plant consumption and that a uniform daily production cannot be specified by the State. Alaska Pipeline agrees to take or pay for a total volume of 50 BCF of natural gas on an if and as deliverable basis.

Phillips Petroleum Company opposes the request for the following reasons:

1. Phillips worked diligently to provide a market for North Cook Inlet gas. No markets for the gas were found in Alaska or on the West Coast of the United States. The only possible market was export of LNG to Japan.

2. Phillips developed the North Cook Inlet gas field at considerable risk and expense for wells, platform, pipelines, liquefaction plant and LNG tankers. All these facilities were designed to utilize all of the gas production from the field.

3. The increased gas production to supply this new market resulted in additional income to the State through royalty and taxes, also substantially increased the tax base and local tax income of the Kenai Borough and town of Kenai.

4. Phillips has negotiated several price increases with their customers resulting in a three fold increase from the original price. Each increase was shared with the State by an increase in the wellhead price used as the basis for royalty payments. While the delivered

price increased about three times the wellhead price increased approximately five times. It is the highest price received by the State for its royalty gas.

5. The taking of the North Cook Inlet royalty gas inkind and separately disposing of it to a third party will impose an economic hardship on Phillips. Such action will necessitate increased production to meet contract requirements and cause earlier abandonment of the platform, pipeline, liquefaction and transportation facilities due to early depletion of the gas reserves. Additional wells will probably be required to meet delivery requirements and compression equipment will be necessary at an earlier date resulting in added costs to Phillips with no increased benefits to Phillips or the State.

Recd for Bd. members 4/5-76 DK

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

April 2, 1976

RECEIVED
APR - 5 1976
Department of
Natural Resources

Mr. Guy T. Martin
Commissioner of Natural Resources
11th Floor, State Office Building
Pouch M
Juneau, Alaska 99811

Dear Commissioner Martin:

The purpose of this letter is to confirm our oral proposal made to the Alaska Royalty Oil and Gas Development Advisory Board during its March 30/31 meeting in Juneau.

The proposal can be outlined as follows:

1. The State take North Cook Inlet royalty gas in kind and sell such gas to AGAS.

2. AGAS will take delivery of the gas at the platform. This presumes that--

   (a) an arrangement can be made whereby, for suitable compensation, Phillips will transport the gas via their existing system to a point adjacent to the LNG plant.

   (b) the APUC waives jurisdiction over the Phillips facilities to the extent that they may otherwise come under regulation due to the transport of the "royalty" gas.

3. The price will be equal to the Phillips price for royalty gas exported to Japan or equal to the highest price paid in the Cook Inlet area for similar quality gas.

4. The proposal is to cover the "life of the contract" and will terminate on or about June 1, 1984.

5. AGAS will take or pay

   This presumes that--

   (a) it may be agreed with the State that royalty will be taken in kind for resale to AGAS on a selective lease by lease basis so that the volume in question will approximate AGAS' North Road requirements or (see (b))

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See OK Gilbreth's memo 4/9/77

Commissioner Guy T. Martin
Continuation Sheet #2
April 2, 1976

(b) if suitable exchange arrangements can be made with others or if AGAS chooses to build the pipeline connection to its Anchorage line--it may be agreed with the State that all of the royalty be taken in kind for resale to AGAS.

(c) The notice date regarding the State taking royalty in kind be so arranged as to permit AGAS a reasonable length of time to make exchange arrangement with others or to build the required pipeline facilities on a reasoned schedule.

6. The volume of gas expected to be taken in kind for resale to AGAS over the life of the contract is approximately 40 BCF with the actual amount being dependent upon the date of commencement, the arrangement agreed to under #5 above and the actual rate at which the field is produced.

7. It is understood that a deliverability feature is not required in this agreement.

Very truly yours,

Harold F. Schmidt
Senior Vice President

dh

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 Anchorage, Alaska 99502 / Phone (907) 277-5551
Telex 25-187

March 22, 1976

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MAR 24 1976
Department of
Natural Resources

Mr. Bill Fackler, Executive Director
State of Alaska Oil and Gas Royalty Board
Department of Natural Resources
Pouch M
Juneau, AK 99811

Dear Bill:

By using reserves out of the Anchorage contract rather than new reserves we have been able to contract for a one year only extension of service on the North Kenai Road. While we are still hoping to have the North Cook Inlet royalty committed to us during this legislative session we have relieved the supply situation temporarily. It should also be noted that Homer Electric Association now has an offer from Kenai Utility Service Corporation and should no longer present a problem with respect to the royalty gas. Copy is enclosed.

Whatever the outcome of our negotiations with Union and Marathon on exchanging versus pipelining, or for some additional gas for the North Kenai Road area, we need to and are prepared to contract for the royalty gas for the life of production. This gas would supplement our present supply for Anchorage which otherwise will soon become inadequate.

We hope the Royalty Board will take action at its next meeting. We expect to attend.

Very truly yours,

Harold F. Schmidt
Senior Vice President

HFS:jdh

Enclosure

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MAR 24 1975
ALASKA ROYALTY
OIL & GAS BOARD

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
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Telex 25-187

March 22, 1976

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MAR 24 1976
Department of
Natural Resources
ALASKA ROYALTY
OIL & GAS BOARD

Mr. Guy T. Martin
Commissioner of Natural Resources
11th Floor, State Office Building
Pouch M
Juneau, AK 99811

Dear Commissioner Martin:

Thank you for your letter of March 17, 1976. We would greatly appreciate it if you could please send us at once copies of the requests for North Cook Inlet Royalty Gas which you have received from Homer Electric Association, Phillips Petroleum, and Pacific Alaska LNG, together with copies of the response(s) made by the State.

We do not propose to enter a "competitive bid", nor is it timely or proper to debate the relative merits of a pipeline compared to exchanging gas when the need is for an urgent decision on committing the gas to us during this session of the legislature. We have presented our case in full to the best of our information and ability, over a period of several months. We agreed to accept the State's request for a Cook Inlet area favored nations clause and we agreed to accept a take or pay provision, neither of which to us appeared to be necessary or appropriate in the circumstances.

We are distressed by your prediction that our offer to purchase this gas is not likely to be presented to this session of the legislature, and by your having indicated that each party must "present its complete case". We know that lower priced gas is available to Homer (but not to us) and that Homer cannot be considered a bona fide contender for this gas. Copy of a letter on this is enclosed. We know that Pacific Alaska LNG already has (indirectly) caused us to have to pay nearly 100% more for gas at the Kenai gas field, and that they too cannot be considered a bona fide contender at present for this gas. We are aware that Phillips would prefer to continue taking this gas for export to Japan, but they are prepared to cooperate to deliver it to us if the State will so decide.

We have now arranged that when our present supply of gas for the North Kenai Road is exhausted in the next month or so we will begin taking gas there which originally was intended for the Anchorage area. It is a stop-gap measure and cannot be considered to be anything but that. We must soon make a decision as to our public responsibility to continue or not to continue such operation.

ALASKA PIPELINE COMPANY

General Offices Located at 3000 Spenard Road
P.O. Box 6288 / Anchorage, Alaska 99502

As you know, in 1972 we acquired acreage in the Susitna Valley in the hope of exploring for additional gas, and in 1974 we commenced a $2.5 million exploratory well, together with an independent partner (Amarex, Inc.). We still hope to continue such exploration, but the State's actions have discouraged our partner from risking further investment in Alaska: legislation to tax reserves in place, criminal prosecution on allegations of ecological damage (which are groundless, to our knowledge and opinion) and the threat of confiscatory production taxes are a compelling disincentive to such further risks. We now have no alternative but to try to stretch our existing reserves as far as possible or to pay what the traffic will bear for additional reserves from existing gas sources. Unfortunately rate making decisions at the Alaska Public Utilities Commission have stalled the Municipality of Anchorage from assembling its waste heat recovery plant which would save 1/2 of the gas now being wasted. This matter has been appealed to the courts. The Commission has acted to inhibit us from purchasing any gas except State royalty gas by refusing to grant flow through tariffs to cover higher priced other new gas, and has refused to reconsider our protest of that decision.

About all we can do, other than pointing our the seriousness of our situation to you, is to consider enforcing conservation of our gas reserves by terminating our contract to serve the Chugach Bernice Lake power plant and to begin interrupting Chugach's other plants since Chugach has a generous reserve of gas at Beluga and can burn oil in Anchorage and at Bernice Lake.

We will attend the March 30 meeting of the Royalty Board, and we can only hope that on further review you will recognize that our proposal is the one and only bona fide offer and that it is clearly in the public interest that we be allowed to purchase the North Cook Inlet royalty gas at the earliest opportunity.

Very truly yours,

Dale Teel
President

DT:jdh

cc: Honorable Jay Hammond, Governor of Alaska, via Mr. Bill Gordon
Honorable George Sullivan, Mayor of Anchorage
Mr. L. J. Schultz, Manager of Chugach Electric Association
Mr. Bill Rhodes, Manager of Homer Electric Association
Mr. Oscar L. Thomas, Vice President of Kenai Utility Service
Alaska Public Utilities Commission
All Royalty Board Members

AGO 801770

Attachments: Commissioner Martin's Letter of March 1[illegible]
Oscar Thomas' Letter of March 17, H. F. Schmidt's Letter to B. Fackler

March 17, 1976

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MAR 24 1975
ALASKA ROYALTY
OIL & GAS BOARD

Mr. Bill Rhodes, General Manager
Homer Electric Association, Inc.
P. O. Box 255
Homer, Alaska 99603

Dear Bill:

Reference is made to our recent conversation regarding a possible natural gas sales agreement between K.U.S.Co. and H.E.A. The purpose of the agreement would be to provide fuel for power generation at a site approximately 6.5 miles north of Wildwood access road on the Kenai Spur Road.

We are of the present opinion that the feasibility exists to provide fuel gas for your proposed generating facilities at a cost considerably below that of any alternate sources known to us. In general, we propose that such an undertaking could be accomplished as follows:

1. The sale would be made under the rates and conditions outlined in Schedule III of our published Tariff, a current copy of which is enclosed herewith. The volume of 4,000 MCF of gas per day mentioned in our discussion represents a total annual volume of 1,460,000 MCF. Computed on a monthly basis the daily sales volume would carry an annual cost of $704,380.00, or an average weighted cost of 48.24¢/MCF. It is noteworthy that if the cost of royalty gas, which might be obtainable from the State of Alaska, was set at 56¢/MCF the differential would be 7.76¢/MCF, or approximately 16%. The annual cost differential would equal some $113,150.00. Although our rates are subject to regulation by the Alaska Public Utilities Commission it is my personal belief that, all things being equal, the rates quoted herein could be sustained throughout the life of our existing gas supply contract which terminates in 1987.

2. Service to your facility would involve a requirement for capital expenditures estimated at $475,000.00 to $500,000.00 (at projected 1977 costs). We would require a non-interest bearing advance-on-construction in the total amount of the initial investment which would be subject to refund in its entirety. The refund would be made at the rate of 10% of the total revenues derived from your account in those calendar years when such revenues equalled or exceeded $700,000.00. The refund provision would, of course, become inoperative

at such time as the initial advance had been returned. Referring back to our illustrated rates and the suggested cost of royalty gas, the annual savings of $113,150.00 combined with a yearly $70,000.00 refund on the construction advance relates to a 2.73 year pay-out, exclusive of the cost of money.

3. The service facilities installed would remain under our ownership with maintenance and operating costs to be born by us.

4. Resale of gas would be prohibited, as would the extraneous use of gas for purposes other than power generation.

5. Point of delivery would be at the downstream flange of a block valve located on the downstream side of a metering run located on your site. Delivery pressure would be 200 P.S.I.G.

6. You may recall our conversation with Mr. Dale Teel, President of Alaska Gas and Service Co. regarding a waiver which would allow us to serve you in his certificated area. He has since confirmed that he would support, before the A.P.U.C., an agreement reached between K.U.S.Co. and H.E.A. that would culminate in your withdrawal from competition for the Cook Inlet royalty gas. Such support would undoubtedly satisfy any objections the A.P.U.C. might put forth before granting us the necessary authorization to proceed.

Some of the provisions suggested herein are unique in our experience. Consequently, final committment to this proposal, or any similar plan, would necessarily involve approval by our Board of Directors.

There are other alternatives which could be considered in connection with the utilization of our currently unused gas reserves. At your convenience we will be most happy to discuss these with you or to further explore the possibilities outlined herein.

Very truly yours,

KENAI UTILITY SERVICE CORPORATION

Oscar L. Thomas, Vice-President

OLT:jc

Enc.

cc: J. M. Covington
Dale Teel

March 17, 1976

Mr. Dale Teel
Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

Dear Mr. Teel:

I appreciate the letter confirming your statements at the February 23, Board meeting. While we share your desire to resolve this issue in a timely manner, a review of the situation indicates a number of items which must be settled first before the Board can proceed.

The Board now has four requests for the North Cook Inlet field royalty gas; Alaska Pipeline Company, Homer Electric Association, Phillips Petroleum and Pacific Alaska LNG. AS 38.05.183 requires the sale of royalty be made to the highest responsible bidder unless the Commissioner with written approval of the Board determines that the best interest of the State does not require it. In this event, the Commissioner must publish the specific findings and conclusions supporting that decision.

The Board must decide the answers to the following questions among others: what are the relative merits of a competitive bid sale compared to a negotiated sale? Which sale is in the best interest of the State? Is there another source of gas supply which could be used? What is the optimum volume of gas to be sold from the State's viewpoint? What are the relative merits of an additional 30 mile pipeline compared to an exchange of gas?

It is obviously essential that each interested party present its complete case to the Board so that the record will reflect all pertinent information. The Board's findings and conclusions will be made based on that record, and this process is unlikely to be carried on in the best public interest under severe time constraints.

The Board must have sufficient time to consider all aspects of this sale in order to make the best decision possible given its assigned statutory priorities. A review of the problems that remain to be resolved indicate that it is unlikely that a sale can be accomplished in time to be presented to this session of the Legislature. We intend to keep working toward that goal, but believe that a good decision is more in the State's interest than a hurried decision.

I want to reiterate my direct assurances to you at the last Royalty Board meeting that an adequate gas supply for Anchorage and all Alaskan consumers is the highest present priority for this Administration. It will continue to be so as we develop this sale. Working not only in the context of royalty gas, but regarding other short-term supply possibilities, it is our intent to see that your supply difficulties are fully and successfully addressed. I look forward to working with you over the coming months on this matter.

Yours truly,

Guy R. Martin
Commissioner

GRM:dk

Alaska Gas and Service Company

GENERAL OFFICES LOCATED AT 3000 SPENARD ROAD
P. O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-5551
TELEX 25-187

March 20, 1976

Senator Mike Colletta
Alaska State Senate
Pouch V
Juneau, Alaska 99811

Dear Senator Colletta:

The amendment to exempt taxes on reserves dedicated to regulated public utilities is contained in SB 699, by the Rule Committee by request. Our attorney, Paul Robison, has prepared a legal memorandum on the propriety and necessity for making this exemption to the reserves tax and a copy of it is enclosed to you.

We hope passage of this bill can be given early consideration, and we will be available for further information if desired.

Very truly yours,

Dale Teel

Dale Teel
President

dh

Enclosure

AGO 801775

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TO

JUSTIFYING THE EXEMPTION OF RESERVES OF REGULATED UTILITIES FROM THE TAX ON OIL AND GAS RESERVES AND SHOWING THAT SUCH EXEMPTION NOT ONLY MEETS THE TESTS OF CONSTITUTIONALITY BUT IS CLEARLY IN THE PUBLIC INTEREST

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JUSTIFYING THE EXEMPTION OF RESERVES OF REGULATED UTILITIES FROM THE TAX ON OIL AND GAS RESERVES AND SHOWING THAT SUCH EXEMPTION NOT ONLY MEETS THE TESTS OF CONSTITUTIONALITY BUT IS CLEARLY IN THE PUBLIC INTEREST

The exemption of:

> "any oil or gas reserves committed to or produced for use or resale by public utilities which are regulated by the Alaska Public Utilities Commission"

as a new sub-section (5) under AS 43.58.020, does not violate the United States Constitution or the Alaska Constitution and is consistent with the legislative policy contained in extant revenue and taxation laws pertaining to the oil and gas industry in Alaska.

An inquiry of constitutionality has arisen with regard to the above proposed exemption.

Our review of the questions leads us to conclude that there are no federal constitutional questions raised by such proposed legislative act, and the only question posed is whether or not such amendment would violate the Commerce Clause or Equal Protection clause, Article I, §8 of, and the Fourteenth Amendment to the Constitution of the United States, and Article I, §1 or Article IX, §4 of the Alaska Constitution.

Although the power of the State to act in this area free from federal restraint is discussed rather fully immediately hereafter, the second question concerning equal protection is of much greater interest and concern to the Legislature and is discussed commencing on page 4.

CONCERNING THE COMMERCE CLAUSE OF THE UNITED STATES CONSTITUTION

Clearly, there is no violation of the commerce clause, because as stated in Modern Constituional Law, Antieau Volume II

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States and their political subdivisions [illegible] realty located there, even though it is owned and used by a firm engaged therein solely in interstate commerce. Comparably, tangible personal property that has acquired a situs there can be taxed by such a state without violating the commerce clause.

In taxing the real and personal property situated and used within its borders, a State may employ any reasonable means of reaching its full or actual value as part of a going concern." (Citing Pullman Company vs. Richardson 261. U.S. 330, 67 L Ed 682, 43 S Ct. 366 (1923); Railway Express Agency, Inc. vs. Virginia 358 U.S. 434, 3L Ed 2d 450, 79 S Ct. 411, (1959) and Adams Express Company vs. Ohio State Auditor, 166 U.S. 185, 41 L Ed 965, 17 Sct. 604 (1897).

At Section 10:54, p. 119 the treatise says:

"Again, in upholding a state tax upon the storage and withdrawal of gasoline which came into a state from interstate commerce and was shortly thereafter to be used to power interstate vehicles, the Supreme Court observed: "Here the tax is imposed on the successive exercise of . . . . the storage and withdrawal from storage of the gasoline. Both powers are completely exercised before use of the gasoline in interstate commerce begins." Nashville, C & St. L.R.Co. v. Wallace (1933) 288 US 249, 77 L Ed 730, 738, 53 S Ct. 345, 87 ALR 1191.

On another occasion, the Supreme Court ruled valid Wyoming's tax of 4 cents per gallon upon all gasoline used in the state, when applied to an airline that brought in the gasoline, kept it in tanks at an airfield, and withdrew it as needed for its planes. "A State," said the court, "may validly tax the 'use' to which gasoline is put in withdrawing it from storage within the State, and placing it in the tanks of the planes, notwithstanding that its ultimate function is to generate motive power for carrying on interstate commerce." Edelman v Boeing Air Transport (1933 289 US 249, 77 L Ed 1155, 1157, 53 S Ct. 591.

Although at this writing no state can tax the use of gasoline or oil as the power moving interstate commerce through the state, any state can tax gasoline or oil as property so long as it is part of the common mass of property within the state, and can by excise tax reach any handling or use of the gasoline or oil up to the moment it begins powering interstate commerce. (Emphasis added.)

In, Institute on Oil & Gas Law & Taxation, Seventh Annual Southwestern Legal Foundation, Matthew Bender & Co. 1956 in a treatise entitled "The Commerce Clause and the States' Power to Tax the Oil & Gas Industry" by Professor of Law Paul J. Hartman of Vanderbilt University, p. 387 at 449, it states:

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to tax any subject of [illegible] diction is an incident of sovereignty, and is one of the residuary powers possessed by each state as a consequence of the delegation by the people of certain enumerated powers to the Federal Government." Citing McCullach v. Maryland 4 Wheat 316 (U.S. 1819).

At pp. 395-396 it sets forth:

"1. Property Taxes on Oil and Gas Transported in Interstate Commerce

After oil and gas have been produced and are being marketed, they may encounter a property tax. The criterion used by the (U.S. Supreme) Court to determine the validity of property taxes on oil and gas transported across state lines has been made to depend to a very considerable extent on whether the tax was imposed before interstate movement had begun, or after it had ceased, or during certain interruptions of that movement. The tests of tax validity have, in most instances, been mechanical with but little consideration given to the economic consequences of the tax in question. It is believed that the cases we shall examine will support that proposition.
In the property tax case of Coe v. Errol, 116 U.S. 517 (1886), the Court combined in one sentence an expression of its desire for a dividing line between a taxable local activity and non-taxable interstate commerce, and a determination of where that line should be, when it said of the tax in question:

"There must be a point of time when they [taxed logs] cease to be governed exclusively by the domestic law and begin to be governed and protected by the national law of commercial regulation, and that moment seems to us to be a legitimate one for this purpose, in which they commence their final movement for transportation from the State of their origin to that of their destination."

"The principles expressed in Coe v. Errol have influenced judicial thinking in the field of state taxation virtually ever since. The doctrine of this case, of course, was coexistent with the idea that manufacture and production were not interstate commerce even though all the products were transported beyond the borders of the producing state and with no realistic separation between the production and the beginning of transportation." Hope Natural Gas Co. v. Hall , 274 U.S. 284 (1927) (production of gas); Utah Power & Light Co. v. Pfost, 286 U.S. 165 (1938); Oliver Mining Co. v. Lord, 282 U.S. 172 (1923); Heisler v. Thomas Colliery Co., 260 U.S. 245 (1922).

However, after the production process was completed and the commodities had started their interstate transportation, the Court has uniformly forbidden the states to impose a property tax on the commodities while in transit. Hughes Brothers Timber Co. v. Minnesota, 272 U.S. 69 (1926), Champlain Realty Co. v. Brattleboro, 260 U.S. 366 (1922); Western Oil Refining Co. v. Lipscomb, 244 U.S. 346 (1917).

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In 71 Am Jr. 2d. Sec. 426. p. 729-730 it states:

> "With respect to state taxation of natural gas, or taxes based upon the production, transportation, or distribution thereof, a state may impose a tax upon the value at the wells of natural gas produced within its limits, although the gas is transported into other states for consumption."

Clearly, there is no federal constitutional question under the commerce clause, and as will be developed in what follows there is no impediment to the proposed amendment under:

EQUAL PROTECTION CLAUSES OF THE STATE OR FEDERAL CONSTITUTIONS

In 71 Am Jur 2d, Sec. 310, p. 624 it states:

> "The power of the legislature to exempt from taxation, although of wide scope, is restricted by fundamental federal constitutional limitations. There is, however, nothing in the Federal Constitution to prevent a state from granting exemptions from taxation, so long as the grant does not violate fundamental rights secured by the Constitution. The power of a state to exempt from taxation is only precluded by the Fourteenth Amendment, where such power is arbitrarily exercised." (Emphasis added.)

The proposed amendment is not arbitrary, and is consistent with the principles governing the legislative prerogatives as will be seen by a consideration of the Alaska Constitution, the authorities in point, and the case law interpreting it.

In 84 C.J.S., Sec. 216, p. 414, it is said:

> "Hence, where not prohibited or restricted in its exercise by constitutional provisions, the legislature of a state has full power to exempt any persons or corporations or classes of property from taxation, but only from taxes within its jurisdiction. The legislature has power to limit the exemption on any terms or conditions whatsoever, according to its views of public policy or expediency, subject only to the limitation that the exemption and the classification on which it is based shall be reasonable and not arbitrary."

Consistent with this stated authority, the Consitution of Alaska, Article IX, provides:

> "Section 4. Exemptions. The real and personal property of the State or its political subdivision shall be exempt from taxation under conditions and exceptions which may be provided by law. All, or any portion of, property used exclusively for non-profit religious, charitable, cemetery, or educational purposes, as defined by law, shall be exempt from taxation. Other exemptions of like or different kind may be granted by general law. All valid existing exemptions shall be retained until otherwise provided by law."

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To the exent that equal protection or equality and uniformity may be impliedly contained in this constitutional grant of authority to the legislature, 84 C.J.S., Sec. 221, p. 427 states:

> "Although examptions of persons or property under some constitutional provisions relating to taxation and exemption have been held to violate constitutional provisions with respect to equality and uniformity, constitutional provisions with respect to equality and uniformity, although restricting and limiting the exercise of the power to exempt, do not prohibit the creation of reasonable exemptions, ..."
>
> "However, the constitutional requirement is violated wherever particular persons or properties, selected arbitrarily from a class on which the burden of taxation is imposed, have been exempted therefrom,[97] and has been held violated if the exemption does not serve a public purpose.[98]

AS TO SPECIFIC EXEMPTIONS OF PUBLIC UTILITIES

The basic observation of fact and law contained at p. 5 of The Economics of Regulation, Chas. F. Phillips, Jr., published by Richard D. Irwin, Inc. (1969) is important:

> "The position of the regulated industries in the American economy is unique. In contrast to most other industrialized countries which have nationalized these industries, we have relied on private ownership, controlled by state and federal agencies, to provide services which are more or less essential to the economy and which are public in their nature." Argued Justice Harlan in Smyth v. Ames: "A railroad is a public highway, and none the less so because constructed and maintained through the agency of a corporation deriving its existence and powers from the State . . . . It performs a function of the State". And Justice Brandeis, in the Southwestern Bell Telephone case, remarked that "the company is the substitute for the State in the performance of the public service, thus becoming a public servant."

The cases cited are the classic U.S. Supreme Court cases of Smyth v. Ames, 169 U.S. 466, 544 (1898) and Missouri ex rel Southwestern Bell Telephone Co. v. Missouri Public Service Comm. 262 U.S. 276, 291 (1923).

The same has been recognized of a natural gas company by the California Public Utilities Commission in Re: Southern California Gas Co. 35 PUR 3d 300 (1960) in which the headnote 7 states:

> "A public utility is created for public purposes and performs a function of the state; it acquires the status of a quasi trustee, p. 309."

The public purpose or public use classification of public utilities has been carried through to the area of taxation. In City of

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Toledo vs. Jenkins, et al., 143 Oh. St. 141, 54 NE 2d 650 (1944)

the Court said at p. 663:

> "That the use of essential public utility property in the operation of the utility is a public use cannot be gainsaid. . . . Public utilities are created to render service to the public and for the service a charge is made. Any incidental use allied to the main public purpose is likewise public use." (Emphasis added).

The headnote (5) at p. 657 concludes that:

> "Use of essential public utility property in operation of a utility is a "public use" within statutory and constitutional provisions relating to exemption of property from taxation." (Emphasis added.)

In a case directly in point with the rationale of the proposed amendment, Utah Power & Light Co. v. Emmit Pfost, U.S. Supreme Court, 286 U.S. 165, 76 L. Ed. 1038, 52 S.Ct. 548 (1932) upheld an Idaho statute which levied a license tax on production of electricity, but which exempted energy used for pumping water for irrigation purposes on lands within the State. The Supreme Court said the exemption was "not precluded by the equal protection clause of the Fourteenth Amendment". (p. 186).

The appeal to the U.S. Supreme Court was from the District Court which upheld the reasonableness of the classification embodied in the exemption based on an earlier decision of the Idaho Supreme Court, Williams v. Baldridge, 48 Idaho 618, 284 Pac. 203 (1930). The Williams case involved a similar Idaho statute which granted to producers of electrical energy an exemption from the general property tax of property used in producing or transmitting power for pumping water for irrigation purposes. The Idaho court said: "The exemption is made to apply to the property of all power companies used in developing or transmitting electrical energy for pumping water for irrigation purposes with certain exceptions. The pumping method is expensive. By minimizing such expense, land, otherwise unfit for cultivation, is made available for settlement. It is well recognized that where the plenary power of the Legislature to exempt from taxation has not been limited by a constitutional provision, it may exercise this power to encourage private initiative and thereby further the public welfare. A classification for

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purposes of exemption must not be arbitrary. In view of the climatic conditions in this State and the necessities of agriculture, we do not believe that a tax exemption statute designed to permit wider use of electrical energy for irrigation purposes raises a classification so arbitrary and discriminatory as to be merely capricious." (Emphasis added).

ALASKA COURT DECISIONS ARE CONSISTENT WITH THE ABOVE STATEMENTS OF AUTHORITY AND CASE LAW

In the case of In the Matter of Delinquent Tax Roll of The City of Anchorage, 1954, 16 Alaska Reports 286 (1956) the Federal District Court held:

"Classification of property under statute exempting from taxation public utility district and association operating utilities under an arrangement with the Rural Electrification Administration, is a reasonable classification." (headnote 4).

"Statute exempting from taxation public utility district and association operating utilities under arrangement with the Rural Electrification Administration was not in violation of territorial organic act which requires only that all taxes shall be uniform upon same class of subjects." (headnote 6).

This decision was reversed in City of Anchorage v. Chugach Electric Association, 17 Alaska Reports 481, 252 F. 2d 412 (1958), but not on the basis of the classification or tax exemption, but on the finding that the legislature had not carried the exemption over into a subsequent amendment of the tax statutes. (See page 494)

As to the question of public purpose, in the case of DeArmond v. Alaska State Development Corporation, 376 P 2d 717 (1962) the legislative act and the appropriation of funds for the development corporation were subject to the public purpose analysis. The case headnotes state:

> 1. "The phrase "public purpose" within constitutional provision prohibiting the levy of a tax or appropriation of public money except for a public purpose represents a concept which is not capable of precise definition, and is a concept which will change as conditions create changing public needs, and whether a public purpose is being served must be decided as each case arises and in light of particular facts and circum-

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stances of each case. Const. Art, 9, §6."

2. "Where the legislature has found that a public purpose will be served by expenditure or transfer of public funds or use of public credit, the Supreme Court will not set aside finding of legislature unless it clearly appears that such finding is arbitrary and without any reasonable basis in fact. Const. Art 9, §6."

The Alaska Supreme Court reaffirmed these statements in the case of Walker vs. State Mortgage Association, 416 P 2d 245 (1966).

Again, in the case of Suber vs. Alaska State Bond Commission 414 P 2d 546 (1966), the Alaska Supreme Court ruled as to public purpose:

"Courts will not interfere with Legislature's exercise of discretion in choosing means to effect a public purpose unless it is clearly shown that legislative determination that a public purpose will be served by means chosen is arbitrary and without any reasonable basis in fact." (headnote 5)

And as to equal protection, the Court ruled:

"No denial of equal protection occurs in regard to legislative enactment if a rational basis for classification contained in the enactment may reasonably be conceived." (headnote 8).

"Demands of equal protection do not require that there be perfect equality and uniformity, or that the entire field of governmental action be covered by one legislative enactment." (headnote 9).

Equating the requirements of equal protection to the 14th Amendment, the Alaska Supreme Court in 12th Century Investment Company vs. City of Juneau, 359 P 2d 783 (1961) ruled:

"The equal protection clause of 14th Amendment does not prohibit inequality in taxation which is not shown to be result of intentional or systematic undervaluation of some but not all of taxed property in single class, USCA Const. Amend. 14" (headnote 3).

"Equal protection does not compel adoption of iron rule of equal taxation; it does not forbid differences in tax burdens founded upon substantive and reasonable differences between objects taxed. USCA Const. Amendment 14." (headnote 4.)

The Alaska Supreme Court reaffirmed these statements in the later case of Hoblit vs. Greater Anchorage Area Borough, 473, P 2d 630 (1970) at Page 632.

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PROPOSED AMENDMENT IS CONSISTENT WITH ALASKA LEGISLATIVE POLICY

Not only does the foregoing legal discussion clearly sustain the separate classification of public utilities as a result of their performance of a public purpose, it is a classification and distinction consistently accorded to public utilities by the Alaska Legislature in the entire scheme of taxation of the oil and gas industry.

Here follows a listing of the oil and gas taxes showing the consistent legislative policy in taxing public utility functions:

Kind of Tax	Description	Status of Public Utilities Regulations
Property Tax, Oil and gas, ad valorem (AS 43.56.010.210)	State Annual tax at 20 mils of value of property for exploring, producing oil or gas, transporting oil by pipeline:	Exempt: retail distribution of natural gas and pipeline systems operated as utility regulated by APUC are exempted by AS 43.56.210(6)
Property Tax ad valorem (AS 43.58.010-200)	State Annual Tax at 20 mils of value of levee on property having proven reserves of oil or gas	Exemption Proposed and justified herein
Motor Fuel Oil Tax (AS 43.40.010-100	Tax per gallon of fuel sold, delivered or transferred.	Exempt- Fuel used in power plants of public utilities to generate electric energy for sale to general public exempted from tax by (AS 43.40.100)

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It is not in the public interest to discourage the acquisition, development, and holding of natural gas reserves by public utilities by taxing such reserves. The public welfare will be served by inducements to public utility companies which are engaged in transmission and distribution of natural gas to the ultimate consumers and to the electric utilities to acquire and hold reserves. The following article from Alaska Construction and Oil is worthy:

> "America's natural gas shortgage is a dismal picture which is only beginning to be perceived in its true dimensions by the American public.
>
> There are now in the United States approximately 40 million homes housing 135 million gas consumers who, for all practical purposes, are incapable of escaping from exclusive reliance upon natural gas.
>
> Virtually 2/3 of our entire population live in homes fueled by natural gas, with no alternative except going without fuel.
>
> To many people, reference to the energy shortage produces thoughts of oil." or coal (added by writer)
>
> Whatever may be the historical explanation for this, the importance of natural gas in the energy picture of the United States cannot be overemphacized. It provides about one-third of all the energy consumed in the nation.
>
> In this era of environmental consciousness, gas assumes even greater importance because it is the cleanest burning of all the fossil fuels.
>
> It is in this total context of the importance of gas that alarm can properly be sounded because of the rapid deterioration of the country's gas supply. Statistics are availabe in abundant measure, but reference to our experience in 1973 dramatizes the need to develop additional supplies. Whereas the country consumed in that year 22 trillion cubic feet, new discoveries accounted for only 7 trillion cubic feet, one-third of what was consumed. If we continue at this pace, the nation will have no gas in the year 1990!
>
> This stark fact accounts for the uniform cry of those engaged in the transportation and distribution of gas that the country expedite domestic exploration, coal gasification, and the importation of liquefied natural gas(LNG)." Alaska Construction and Oil, April 1975, page 32.

There can be no more legitimate public purpose than to encourage, by all means, including tax incentives, Alaska's natural gas industry, and particularly Alaska's public utilities utilizing gas to do everything in their power to acquire and hold as much natural gas in terms of supply and reserves as they reasonably can

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to insure that this essential space heating resource and electric power generating resource will not be in short supply during the adverse winteres experienced in Alaska, and at today's prices rather than at costs of several times today's prices a few years hence.

PRACTICAL NECESSITY FOR EXEMPTION OF PUBLIC UTILITIES FROM THE TAX ON THEIR GAS RESERVES.

Although the reserves tax on regulated Public Utilities may produce only 1 to 2 million dollars per year in State Revenues, substantially all of this amount, when determined, will be passed on to the Utility Rate Payers unless the requested amendment is enacted. Considerable effort, some of which may be counter-productive, has already been expended by members of this Legislature to minimize public utility rates charged the consumer.

The Public Utility Commission has already granted Alaska Gas & Service Co. (ANGC) and Kenai Utility Service Corporation authority to pass this reserve tax to be paid by the utilities, on to the consumer. This will not only result in additional operating costs to these utilities (detailed computation and separate identification on customers' bills), but will result in circuitous, cumbersome, and costly re-computation and billing by the power companies (Municipality of Anchorage-ML&P, and Chugach Electric Association, Inc.) of the reserves tax collected from them by the gas utilities for gas purchased for electrical power generation. The electric utilities, through tax flow through provisions either existing or yet to be approved by the Alaska Public Utilities Commission, will have to perform detailed accounting computations and itemized billing to collect this portion of the reserves tax from their individual electric consumers.

We have not explored the extent of the adverse effect of the pass-on of this tax to the Kenai Native Association in their generation and supply of electricity to their Wildwood facilities with gas purchased from Kenai Utility Service Corporation on which they too would pay the reserves tax.

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Proceeding to the next [illegible]

the impact on electric utilities and their rate payers, consider the fact that Chugach Electric Association which, if the exemption is not granted, will also have to pay and collect from its customers the taxes on its Beluga gas reserves which are also used in generating power for some or all of its customers in the Anchorage, Eagle River, Palmer, Wasilla, Talkeetna, Seward, Hope, Moose Pass, Sterling, Homer, Seldovia and Whittier areas.

It is worthy of note that should gas become available to serve Fairbanks, Kodiak or other areas while this tax is in effect, users there as well as their electric rate payers would be equally affected.

The writer is not familiar with the effect and impact of this tax on the community of Barrow and leaves it to their representatives to so determine. Hopefully, the legislators who have read this far will now consider the further and seemingly impossible dilemma facing the public utilities and the Alaska Public Utilities Commission if they are not given the exemption here sought.

The reserves tax first impacts the producer. Marathon-Union as to Alaska Gas & Service's and Kenai Utility Service Corporation's and Standard Oil of California as to Chugach Electric Association's reserves. In computing the tax they are given credit as to certain other taxes they have paid. AS 43.58.030, 43.58.180 and 43.55.018. These credits inure to the benefit of the utilities named herein and their rate payers to the extent such credits are available during the first two years the tax is collected. However, we have been advised by the Department of Revenue and the Oil and Gas Division of the Department of Natural Resources that these producers will continue to receive credits under 43.58.180 in future years until the full amount of the reserve tax has been offset. We have not been able to learn and understand how this will work and have absolutely no idea whether these future credits can and will be passed on to the public utilities in adjustments to cost of future gas purchases. If it does not occur it is unfair to all of the rate payers who will have paid the reserves tax the first

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two years.

But what if these utilities do receive future years credits over the life of the gas fields or until the full amount of the reserves tax has been offset? Can the utilities simply treat it as an overall reduction in operating expense (cost of gas)? If so, new customers who did not pay the tax during the first two years when it was collected from them will participate in the benefit of the passed through credits at the expense of the rate payers who actually paid it. If the Commission or a court in an action by a rate payer who paid the tax initially requires the utilities to keep records of the names and amounts of the first customers who paid the tax for the first two years and give credits or refunds to them the enormity of the exercise and its expense over a period of say 15 years would conceivably equal the amount of the credits or refunds and the cost of this service would then be borne by all new rate payers who would receive no benefit therefrom along with the old rate payers. This leaves, without discussion, the discouraging problem of dealing with credits or refunds accruing to the original tax paying rate payer who has discontinued service, moved, died, or if a business entity, ceased to exist.

Relief by the Legislature from this nightmare is earnestly solicited by enactment of the Amendment appearing at the beginning of this Memorandum.

ROBISON, McCASKEY, REYNOLDS & FRANKEL

By Paul F. Robison
Paul F. Robison

March 17, 1976.

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ALASKA PIPELINE COMPANY

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3000 SPENARD ROAD
PHONE (907) 277-5551

March 9, 1976

Mr. Guy Martin
Commissioner of Natural Resources
State Office Building
Juneau, Alaska

Dear Commissioner Martin:

We wish to confirm to you that we have assented (at the Board's Meeting on February 23) to the "take or pay" requirement for purchase of royalty gas, on the condition that it would be available for the life of production rather than just to June of 1984.

We are not able to confirm with Marathon that they have considered or will consider extending our contract by more than one year. We certainly will continue negotiating with them and hope that some way can be found to avoid an emergency in service to the Chugach Bernice Lake power plant.

We have discussed Homer's interest in purchasing gas for a new power plant with Mr. Oscar Thomas, who is the Vice President and General Manager of Kenai Utility Service Corporation, and further confirmed the comments we made by letter of February 27. For the reasons given, we cannot believe Homer is a bona fide competitor for North Cook Inlet royalty gas and we cannot do more than to assure them that we would utilize this gas for service to Bernice Lake whether or not they purchase it from Chugach; and that if they build the new power plant in our service area, we would also utilize this gas to serve such a new plant. We cannot guarantee any particular price for the gas, however, because it is subject to the decision of the Alaska Public Utilities Commission.

We hope the Royalty Board will act soon to resolve this matter.

Very truly yours,

Dale Teel
President

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RECEIVED
MAR 11 1976
Department of
Natural Resources

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MAR 12 1975
ALASKA ROYALTY
OIL & GAS BOARD

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RECEIVED
MAR 2 1976
Department of
Natural Resources

February 27, 1976

Mr. Guy Martin
Commissioner of Natural Resources
State Office Building
Juneau, Alaska

Dear Commissioner Martin:

We were very surprised that Homer Electric Association appeared at the February 23 meeting of the Roaylty Board and represented that they would be equally or more qualified to be the purchaser of North Cook Inlet royalty gas. We have written them to ask that they reconsider and withdraw from this matter and to reassure them that we would utilize the royalty gas to serve the Bernice Lake power plant whether or not Homer may be successful in purchasing it from Chugach Electric and/or to serve the additional unit if Homer is successful in obtaining funding for such a unit.

It has come to our attention that Homer could purchase gas from Kenai Utility Service Corporation (KUSCo) within the city limits of Kenai or on the premises of "Wildwood Station", which now belongs to the Kenai Native Association. KUSCo has adequate reserves and deliverability to provide this service and now has a filed tariff (SCHEDULE III - INTERRUPTIBLE POWER PLANT SERVICE) in effect which would provide Homer's requirements at less than 50¢ per MCF as compared to 60¢ or more for royalty gas from the North Cook Inlet gas field. In fact, KUSCo will forfeit these reserves back to the producers if no sale is effected.

It would appear that Homer's requirement for fuel for an additional generating unit would be met almost ideally by gas from KUSCo. A copy of KUSCo's Schedule III is enclosed as information.

We have attempted to purchase gas from KUSCo, but are not able to do so because their contract specifies that it is for use at Kenai (rather than resale at wholesale). We believe that the facts in this matter do not admit any bona fide "competitiveness" from Homer for State royalty gas, and that the public interest requires that we be given priority consideration. Homer cannot make use of any gas at present, nor in fact can it now commit to do so at some future date since such commitment would be contingent upon its purchase of the Bernice Lake power plant and/or its purchase of an additional generating unit. Homer has lower priced gas available from KUSCo. Homer has no experience in the handling of high pressure natural gas.

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

KUSCo's cost of gas is fixed by contract until 1986, at a very favorable price. With the known recent increases in price and demand for Alaskan natural gas and the increases which may reasonably be expected in the future, it appears to us that the customers of Homer are eminently better served by utilizing a source of gas that has a known cost for the next ten years. In our own situation, by averaging this relatively small amount of higher priced gas into the lower cost of our present supply, our customers will not be adversely affected by the higher priced royalty gas to the extent that customers of Homer would be.

We ask the Royalty Board not to allow Homer's last minute appearance to delay the negotiations of royalty gas to us, and that the sale be presented for approval by the legislature this session.

We will attend the March 2 meeting of the Royalty Board, to answer any further questions.

Very truly yours,

Dale Teel
President

dh

Enclosure

cc: Bill Rhodes

Canceling ORIGINAL OF Sheet No. 32.1

JUN 10 1975

State of Alaska
Public Utilities Commission

KENAI UTILITY SERVICE CORPORATION

KENAI UTILITY SERVICE CORPORATION

SCHEDULE III - INTERRUPTIBLE POWER PLANT SERVICE (I)

AVAILABILITY: To natural gas service used for the generation of electricity or steam as central station service.

1. Once instituted, application of this schedule shall continue for not less than twelve (12) consecutive months.

2. Service under this schedule may be interrupted on not less than two (2) hours notice, and for not more than ten (10) days in any calendar month, during the period October through March.

3. While receiving service under this schedule, the customer shall maintain standby fuel and facilities, in the interest of public health and welfare, so that curtailment or interruption of service hereunder will be compatible with customer's power plant operation.

CHARACTER OF SERVICE: Natural gas having a heating value which is approximately 1,000 BTU per cubic foot.

MEASUREMENT: All deliveries shall be metered volumetrically and corrected to a base of 14.65 psia and 60° F. assuming absolute pressure of 14.7 psia.

MONTHLY RATE:

For the first	1,500 MCF or less per month	$1,100.00
For the next	8,500 MCF per month	$ 0.59/MCF
For the next	40,000 MCF per month	$ 0.54/MCF
For the next	50,000 MCF per month	$ 0.49/MCF
For the next	200,000 MCF per month	$ 0.44/MCF
For all over	300,000 MCF per month	$ 0.39/MCF

SUMMER SEASONAL DISCOUNT: During the months of April through September, a seasonal discount of $0.05 per MCF will be allowed, provided however, that such discount shall apply only to the first 150,000 MCF per month, and provided further that the monthly minimum bill shall be not less than $1,100.00

SERVICE REGULATIONS: Service supplied hereunder is subject to the orders of regulatory bodies having jurisdiction, and to the Company's Rules and Regulations currently on file.

Tariff Advice No. 6 Effective: July 20, 1975

Issued by: KENAI UTILITY SERVICE CORPORATION AGO 801793

By: [signature] Title: Vice-President

Alaska Gas and Service Company

GENERAL OFFICES LOCATED AT 3000 SPENARD ROAD
P. O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-8551
TELEX 25-187

February 25, 1976

RECEIVED
MAR 1 1976
Department of
Natural Resources

Mr. Bill Rhodes
Homer Electric Association, Inc.
P. O. Box 255
Homer, AK 99603

Dear Bill:

I believe our mutual interests generally and especially our mutual interest in the State royalty gas from the North Cook Inlet are thwarted by the appearance of our being in competition for this gas, as at the Royalty Board meeting of February 23. I also believe that if we could resolve this matter between ourselves, the Board was (and is) ready to approve the committing of this gas to us for the life of the field, and to so recommend for early approval in this session of the legislature. I fear that if we do not resolve the matter, then the Board (or the legislature) may not act in time for us to begin taking this gas prior to the termination of our present contract with Union-Marathon, and thus there would be a necessity to interrupt gas service to the Bernice Lake power plant. As you know, this plant burned oil for the first ten years and it is still equipped to burn oil upon such interruptions of gas. But the price of oil is now much greater than our price for gas, and the availability of oil may not be assured even at that price.

Service to this plant requires 50% to 100% of the royalty gas available on a daily basis, and we have from the outset been representing that we would utilize the royalty gas to maintain this service. Thus there is in fact no competition between us for the North Cook Inlet royalty gas except as to any "handling charge" we would require for making the sale. As you know, we now have "postage stamp" rates (uniform throughout our service area). All of our prior filed rates for power plants have been extinguished, and replaced by special contracts. The special contracts must be filed with the Alaska Public Utilities Commission, and thus our "handling charge" is subject to the approval of the Commission. We already have obtained approval from the Commission to commingle royalty gas with Kenai Field gas and to "flow through" the increased average cost of gas to our customers throughout our "postage stamp" distribution system. To the extent that you may take portions (or all) of the royalty gas from us, we should exclude its increased cost from the calculation of "flow through" to our other customers, in order not to compound any cost increases. This would require us to depart from the "postage stamp" rate design, as to our sale to you only.

Alaska Gas and Service Company
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TELEX 25-101

We believe that the urgency and importance of our reaching early and appropriate agreement with the State are such that we should ask you to withdraw your request to purchase this royalty gas. To encourage you to do so, we would assure you that if you are successful in purchasing the existing Bernice Lake power plant from Chugach Electric Association and if you are further successful in obtaining funding to build additional generation facilities to serve Pacific Alaska LNG Company, we would commit to you the gas necessary for this generation out of the State royalty gas we are attempting to purchase. Thus you would be assured of reasonable pricing for fuel for these requirements. We are experienced in the handling, measurement, and pressure regulation of natural gas, and we believe our record of operating as well as our APUC Certificate of Public Convenience and Necessity fully qualify us to provide natural gas service to you.

We expect that because of our existing organization and expertise, your cost for fuel from us, including any "profit" to us, may be less than for your purchasing this gas directly and handling it. Your investment for pipelines and connections, odorization, measurement, and pressure and temperature regulation would be substantial. It would require compliance with the Pipeline Safety Act and perhaps a Certificate from the APUC. The safe handling of gas requires competent engineering and operations. We have this capability. Moreover, we are well suited to obtain gas for your requirements in excess of the availability (or the deliverability) of royalty gas, since we have a relatively large reserve at the Kenai gas field and we are continually negotiating for additional gas supplies.

I cannot over-emphasize the adverse effects of allowing the appearance of competition to preclude the earliest possible conclusion of negotiating the sale of the North Cook Inlet royalty gas to us. Personally, I would not expect early action by Chugach to sell the Bernice Lake plant to you. Several times in the past we have negotiated with Homer, even to the point of having a contract cleared with the respective attorneys, only to have REA threaten to withhold further financing if Homer were to begin generating its own power. Similarly, I would not expect that Pacific Alaska LNG Company can act early (by 1979) to utilize the royalty not taken at Bernice Lake. In contrast, we could begin taking most of the royalty gas almost immediately, and certainly we could take all of it upon completing a pipeline intertie in one year or less. If, because of the apparent competition, sale of this royalty gas were to be submitted to a bidding process, the result might be an even higher price than the present royalty payment and an ultimate sale to a third party (even Phillips) who would not be oriented to solving either our short term or long term needs, or Homer's.

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P.O. BOX 6140 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-3881
TELEX 25-187

I hope that we can reach agreement prior to the meeting of the Royalty Board next Wednesday, March 3. I believe that if you could withdraw from this matter by letter or by so indicating on a copy of this letter, we could expect to obtain this royalty gas at the earliest opportunity, which is in our mutual interest for both the short term and the long term.

Very truly yours,

Dale Teel

Dale Teel
President

DT:jdh

bcc: Bill Fackler

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

RECEIVED
FEB 09 1975
ALASKA ROYALTY
OIL & GAS BOARD

February 3, 1976

RECEIVED
FEB - 6 1976
Department of
Natural Resources

Mr. Bill Fackler
Executive Director
State of Alaska Oil and
Gas Royalty Board
Department of Natural Resources
Juneau, Alaska

Dear Bill:

We are continuing our negotiations with the various producers for a supply of natural gas to serve our customers on the North Kenai Road. It now appears that we will be able to continue purchasing from Union-Marathon for the duration of the term of the contract, which is to May 1, 1977. After the remaining reserve quantity has been taken (within a few months from now), we would expect to be paying them the price we offered for state Royalty Gas -- 55.8¢ per MCF.

We have not resolved the longer future of a gas supply for the Kenai Road area, however, and we are continuing negotiations toward that objective.

As to our purchasing Royalty Gas, we have concluded that we probably will have to build a pipeline to move this gas into our pipeline to Anchorage rather than to rely on the paper exchanges we had visualized earlier. This in turn leads us to require a longer term than was proposed by the Royalty Board at the December meeting, since it is impractical for us to try to amortize such a pipeline over the 7 years or less which would be available to June of 1984. For this reason, we ask that the Board should reconsider and allow our purchase of Royalty Gas to continue for the life of production from the North Cook Inlet Gas Field.

We also can foresee the strong desirability or necessity of providing that if we are at times unable to take the full quantity of this Royalty Gas, no penalty should attach to such inability except that we would forfeit the right to receive any gas we were unable to take from day to day. We realize that the producer (Phillips) would have to assent to such a provision and we have not obtained such assent as yet. However, we hope that it can be obtained without undue difficulty.

While we are continuing our efforts to obtain more gas for the North Kenai Road area directly from the producers, and while we are optimistic about the prospect for success in these efforts, our need for obtaining the Royalty Gas is not diminished. Accordingly, we request that the changes we are proposing above be considered by the Royalty Board at its meeting on February 23.

We also would ask that you confirm the Royalty Board's support of our request to the Alaska Public Utilities Commission with respect to its jurisdiction over Phillips and Phillips' facilities, as Phillips has discussed in their letter of January 9, 1976 (copy enclosed). The need for such support was discussed at the Royalty Board's December meeting, and we would hope that you can so confirm to the Commission at the earliest opportunity. The sooner a waiver is received from the Commission the better will be our prospect of concluding the various negotiations and proceeding toward the necessary pipeline construction.

We will plan to attend the next meeting of the Royalty Board unless we are otherwise advised in the meantime.

Very truly yours,

Dale Teel
President

DT:dh

Enclosure

cc: Mr. John Horn, Phillips
Mr. Bart Emery, Marathon
Mr. Larry Bradford, Union
Mr. Roger Kemppel, City

RECEIVED
FEB 09 1975
ALASKA ROYALTY
OIL & GAS BOARD

AGO 801798

Transcript of minutes, p 40 + 43 attached were provided by Jo-Ann Leahy 4/14/77 as satisfying the reference for Ed. support for a waiver from APUC for Phillips pipeline & loc.

PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA 74004 918 661-6600

NATURAL RESOURCES GROUP
Gas and Gas Liquids Division

January 9, 1976

North Cook Inlet Field
Royalty Gas

File: 1-Ho-20-76-G&GL

Mr. Dale Teel
Alaska Gas & Service Company
P. O. Box 6288
Anchorage, Alaska 99502

Dear Dale:

Relative to Alaska Pipe Line's efforts to acquire the State's royalty gas from the North Cook Inlet Field operated by Phillips for purposes of good order, we set forth below certain matters, the satisfactory resolution of which is a necessary prerequisite to any participation by Phillips.

1. The 5.55¢ per Mcf is not an appropriate place differential for the gas. This is a number that has been worked out and used as a deduction for computing wellhead value of the gas for purposes of paying royalty and taxes. It does not, however, represent what we believe the appropriate differential for the arrangement you contemplate. We are willing to enter into negotiations with you in an effort to arrive at a satisfactory number.

Where are the differences?

2. Neither Phillips nor any of its facilities can be subjected to possibility of being classified as a public utility by the Alaska Public Utility Commission. The utility aspects of any exchange of gas involving North Cook Inlet gas or facilities must be resolved to the satisfaction of Phillips prior to Phillips entering any agreements.

3. Since Marathon Oil Company would be involved in any exchange of North Cook Inlet Field gas, it would be APL's responsibility to work out these arrangements with Marathon.

The above doubtless will not be the only complicating matters to arise, however, we will work with you in an effort to mutually resolve additional problems as they develop.

Very truly yours, AGO 801799

John Horn

JH:pla

FILED

Transcript
Alaska Roy Oil & Gas Dev. Adv. Bd
Dec. 10 & 11, 1975

Board Meeting Called to Order 10:10 a.m. Dec. 11, 1975, Chairman Martin brought the board back into session.

Mr. Martin:

We are at the point on theagenda where we take up discussions and reports. Fred I wonder if, Fred Boness from the Attorney Generals Office could just briefly outline the report that he filed on the Arn G-Phillips situation regard to public utilities.

Fred Boness:

At the last royalty board meeting Phillips raised the possibility that a sale of, or the state taking its gas in-kind might have the effect of subjecting the Phillips pipeline to either FPC or APUC jurisdiction depending on where the gas was sold. Specifically ?. APUC jurisdiction if it was sold to Anchorage Natural Gas Company. I reviewed that possibility and filed a memorandum with the commissioner which indicates that it was my conclusion that there was indeed a possibility that at least limited jurisdiction by the Public Utilities Commission and cited the situation which took place in the Marathon, the Union Marathon Pipeline which exists from the Kenai field to the LNG plant. It does have sales off that to the City of Kenai and Anchorage Natural Gas and there is limited jurisdiction exercised by the PUC in that pipeline. I believe the situation would likely be an anologoas to the Phillips Pipeline.

Mr. Martin:

Fred, is it your view that, if jurisdiction distinct applied, and you considred that a liklihood or at least the ~~district~~ possibility, could that jurisdiction be waived as a precedent.

Mr. Boness:

The Public Utility Commission does have the authority to grant exemptions under one of its provisions and that could be exercised. The exact, the exact determinance of whether it would be or not specified in the law and it would require a ruling by the APUC.

Mr. Martin:

Do you have any idea, or does anybody have any idea, what might be the time consideration on a waiver at that time?

Mr. Boness:

No, I'm afraid I don't. I haven't talked to the APUC. I would think it would be perhaps two, three-maybe not-I would not think more than six months. Certainly the APUC acts much faster and swifter than the FPC. I think we have that kind of comparison.

End discussion this topic.

guy Martin

until all transportation or exchange arrangments have been completed to the satisfaction of the parties involved. Now detailing all aspects of that, I would like to point out some points. First: with regard to the termination date of the contract it is related to the termination of the Phillips contract and the possible implications of a failure Phillips to produce beyond that point. Second; the price is in fact, the highest price in the area and it is my feeling that this is an important aspect of the agreement for the reason that the board may very well, the baord and the state may very well, wish from time to time to be in the position of doing something which is unpalatable, as it is in this case, to remove royalty gas from the user that has served an important public purpose in the state. But the board I think and the state will not want to be in position of attempting to set prices from time to time and place to place and to chose from among consumers in the state. The safest and most consistent standard therefore should be the highest price and we intend that this term will bear that out. We have also indicated that the point of delivery will be the wellhead, and, while we believe that will substantially alter the nature of the original offer made by Alaska Pipeline Company, we believe it is quite important that the state not be responsible for that transportation to shore. That is be a negotiated item between Phillips and the purchaser. The state I should say at that point, that after having made this desision, fully intends that the decision be carried out and we think it is in the best public policy that this be carried out. I am requesting now and I think we will be requesting later that some terms of agreement, some measure of agreement, some point of agreement be found between Phillips and A N G for the delivery of this gas. I think that terminates my discussion with the exception of one point and that is that the PUC problme has not been one that has escaped our attention. It's our believe that this is a separate function, not one that the board can control as was suggested in the A N G offer. It was suggested in the A N G offer that the state would be capable of somehow dictating the outcome of that regulatory procedure. This, of course, is not the case, we will not attempt to do so. Now, I will indicate that it will be my intention to communicate the sentiments I just communicated with regard to our desire for success of this sale to the PUC with the request that they formulate the necessary procedures to protect Phillips from regulation in order to make this sale successful. So let me terminate my remarks at this time and ask for the Comments and response of the board.

John Horn:

Mr. Chairman, let me make one small comment, the expiration date of our contract with the Japanese is June 1, 1984 rather than May 1.

Mr. Martin:

Thank you, John, very much. I will amend that.

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER / POUCH M — JUNEAU 99811

Alaska Royalty Oil & Gas Development Advisory Board

January 12, 1976

RECEIVED
JAN 2 c 1976
Department of
Natural Resources

Mr. Dale Teel
Alaska Pipeline Company
P.O. Box 6288
Anchorage, Alaska 99502

Dear Mr. Teel:

At the January 7, 1976 meeting of the Alaska Royalty Oil and Gas Development Advisory Board I was instructed to write you concerning evidence of your efforts to obtain a gas supply from the local gas producers to replace the "Nikiski" contract.

You will remember that this point was discussed by several members of the Board with you at the December meeting. The Board desires copies of your solicitations to the local producers and their replies to your requests.

I hope that this will not be a great inconvenience to you and that we may expect an early response.

Yours Truly,

William C. Fackler
Executive Director

RECEIVED
JAN 20 1976
OIL & GAS BOARD

cc: Board Members

See enclosures:

Alaska Pipeline Company to Union
Alaska Pipeline Company to Marathon
Letter from Marathon
Letter from Phillips

PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA 74004 918 661-6600

NATURAL RESOURCES GROUP
Gas and Gas Liquids Division

January 9, 1976

North Cook Inlet Field
Royalty Gas

File: 1-Ho-20-76-G&GL

Mr. Dale Teel
Alaska Gas & Service Company
P. O. Box 6288
Anchorage, Alaska 99502

Dear Dale:

Relative to Alaska Pipe Line's efforts to acquire the State's royalty gas from the North Cook Inlet Field operated by Phillips for purposes of good order, we set forth below certain matters, the satisfactory resolution of which is a necessary prerequisite to any participation by Phillips.

1. The 5.55¢ per Mcf is not an appropriate place differential for the gas. This is a number that has been worked out and used as a deduction for computing wellhead value of the gas for purposes of paying royalty and taxes. It does not, however, represent what we believe the appropriate differential for the arrangement you contemplate. We are willing to enter into negotiations with you in an effort to arrive at a satisfactory number.

2. Neither Phillips nor any of its facilities can be subjected to possibility of being classified as a public utility by the Alaska Public Utility Commission. The utility aspects of any exchange of gas involving North Cook Inlet gas or facilities must be resolved to the satisfaction of Phillips prior to Phillips entering any agreements.

APC's

3. Since Marathon Oil Company would be involved in any exchange of North Cook Inlet Field gas, it would be APL's responsibility to work out these arrangements with Marathon.

The above doubtless will not be the only complicating matters to arise, however, we will work with you in an effort to mutually resolve additional problems as they develop.

Very truly yours,

John Horn

JH:bla

AGO 801803

Alaska Royalty Oil & Gas Development Advisory Board

January 2, 1976

Mr. Dale Teel
Alaska Pipeline Company
P.O. Box 6288
Anchorage, Alaska 99502

Dear Mr. Teel:

The Royalty Board has received your letter of December 12 with proposal revision of pages 3 & 4 of your "Draft for Discussion Purposes" dated December 7. The same letter suggested January 2 as a most probable date for your return from vacation.

In the interest of continued progress in this matter, I am enclosing a copy of the Board provisions included in the Commissioner's proposal for the sale of North Cook Inlet field royalty gas.

Following your review, the Board would appreciate your comments on the provisions.

Yours Truly,

William C. Fackler

William C. Fackler
Executive Director

Enclosure

AGO 801804

"Commissioner's Proposal in Concept" was approved by Jordan Cash of Royalty Board has being the above mentioned "Board provisions included in the Commissioner's proposal for the sale of North Cook Inlet field royalty gas"

See also
April 26, 1976

North Cook Inlet Field Royalty Gas
Commissioner's Proposal in Concept

The Commissioner of Natural Resources has recognized that the increasing growth of the Cook Inlet area of Alaska with its resultant increase in the use of natural gas requires that additional natural gas reserves be allocated for that purpose from State of Alaska royalty gas. From the standpoint of size of uncommitted gas reserves, geographical location and possible pipeline access, the North Cook Inlet field royalty gas appears the best available supply at this time. Pursuant to AS 38.05. 182 the Commissioner proposes that it is in the best interest of the State to take in kind the State's royalty share of the gas production from the North Cook Inlet gas field and requests the consent of the Alaska Royalty Oil and Gas Development Advisory Board for this change.

The Commissioner further proposes to dispose of the North Cook Inlet field royalty gas to Alaska Pipeline Company and its subsidiaries through a negotiated contract. The proposed contract will contain the following provisions:

1. Purchaser agrees to take 1/8 of daily production from the North Cook Inlet gas field on an if and as deliverable basis for the contract period. The State will report to the Purchaser each month the amount of royalty gas produced by Phillips during the prior months.

The approximate average daily royalty gas share of the production from Phillips' North Cook Inlet field platform is 17,000 MCF. Gas production from the platform varies as LNG plant needs dictate therefore no daily amount can be specified.

2. Point of delivery will be the wellhead.

3. Purchaser is responsible for measurement costs, and any compression or dehydration costs if or when necessary.

4. The contract expires on June 1, 1984, unless extended by mutual agreement for a period not to exceed one year.

5. The price of the gas will be equal to the price the State otherwise would have received from Phillips for its royalty gas for export as LNG to Japan; but not less than the highest price paid by any purchaser in the Cook Inlet area for a similar sale of gas of similar quality. The price will be adjusted yearly on the anniversary date of the contract.

6. The contract shall not be effective until

-all necessary permits and authorizations by governing bodies are obtained

-all transportation or exchange arrangements have been completed to the satisfaction of the parties involved.

-six month's notice required under lease

The Commissioner request approval of the above proposed conceptual plan by the Alaska Royalty Oil and Gas Development Advisory Board.

North Cook Inlet Field Royalty Gas
Commissioner's Proposal in Concept
Procedure

1. Commissioner determines that the best interests of the State are served by the taking in kind of the State's royalty gas share of the production of the North Cook Inlet gas field.

   Requires consent of the board.

2. Commissioner determines that it would not be in the best interest of the State to sell the North Cook Inlet field royalty gas by competitive bid.

   a. Requires prior written approval by board.
   b. Requires Commissioner make public in writing the specific findings and conclusions upon which that determination is based.

W B Em
Manage. .tural Gas Division
Production US & Canada

Marathon Oil Company

Findlay Ohio 45840
Telephone 419/422 2121

December 19, 1975

Mr. Dale Teel, President
Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

Dear Dale:

RE: GAS SUPPLY FOR THE
NORTH KENAI ROAD AREA

This will acknowledge receipt of your letter dated December 12, 1975, and the attachments thereto, in connection with the above referenced subject.

Marathon is not presently in a position to discuss a long term commitment of up to 50 BCF of our Cook Inlet Area gas reserves.

We are fully aware of your supply situation on the North Kenai Road and we are willing to enter into a new short-term contract with you similar to our existing contract of May 1, 1967, with appropriate changes to fit current circumstances and subject to the following general quantity and price provisions:

1. The contract expiration date would be May 1, 1978, or until the seller has delivered a total additional five (5) BCF of gas, whichever occurs first. If your company were to contract for one-half of this volume from some other company, this volume would be reduced by one-half or to 2-1/2 BCF.

2. The price for the additional gas would be 55.8¢ per MCF in accordance with your offer. This price would become effective for gas taken after your present commitment of ten (10) BCF has been delivered.

We recognize that the foregoing proposal will not solve your long-term supply problem, but we feel it will provide you sufficient time to further consider your supply situation.

If the foregoing proposal is of interest to you, I would be glad to meet with you sometime during the week commencing January 12, 1976, to discuss this matter further. Please let me know as soon as possible if you desire such a meeting.

Yours very truly,

W. B. Emery II

W. B. Emery II

WBEKK:sm

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

December 12, 1975

DUPLICATE
ORIGINAL

Mr. Bart Emery
Marathon Oil Company
539 South Main Street
Findlay, Ohio 45840

Dear Bart:

The State of Alaska Oil and Gas Royalty Board has voted to authorize the Commissioner of Natural Resources (Guy Martin) to negotiate the sale of North Cook Inlet Gas Field royalty gas to us, subject to final approval at the Board's January meeting and then approval of the legislature.

(Sandwich-1)

I have sent Sam informally copies of all correspondence, etc. in this matter except the enclosed preliminary drafts of proposed memoranda of agreement (APC with Union as operator, and APC with State); letters of support by City and Chugach; and the material I obtained at the Board meeting of December 10.

Board member (Dr.) Arlon Tussing (University of Alaska Economist) questioned whether or not we had diligently tried to get gas from "others," and I expect he will inquire further on this point at the January meeting. The vote was unanimous, with that reservation. Accordingly, I am writing now to ask whether or not Marathon would be willing to offer us our requirements up to 50 BCF over a period prior to June 1, 1984. Deliverability would be up to 15 MMCFD; take or pay at 10 MMCFD; delivery at any combination of the Kenai master meter and the three existing taps on your Kenai to Nikiski pipeline; at the price of 55.8¢ per MCF but not less than the highest price paid by any purchaser in the Cook Inlet area for a similar sale of gas of similar quality, adjusted yearly on the anniversary date of the contract, provided that we would have the option to terminate on one year's notice upon paying such higher price.

This same proposition was mentioned to John Horn of Phillips verbally, and his response was that since the royalty purchase (by others than us) would not be eliminated by such a decision, he would prefer to see us proceed to

take the royalty. If you, or Union, would prefer to sell to us at these terms, from either of you individually or as equal partners, rather than for us to take this 50 BCF of North Cook royalty, I would like to discuss it further with you at the earliest opportunity. If you are not interested in this proposition, I would like to have it of record in order to have an answer for Dr. Tussing. Also, we would have to work out a short term and long term solution to a gas supply for the North Kenai Road area: we expect to be out of the present 10 BCF in April 1976, but even without delay or opposition we may not be lined up for North Cook Inlet gas before that date or maybe even six months after that date. I would propose for your consideration that we should "borrow" gas from the "Anchorage" contract, on the basis that we would repay through exchange from royalty gas in the ratio of 2 to 1, or, if we do not get gas to exchange, we would need to have one year's extension of the Nikiski contract at the present price etc., but agree that all deliveries we take from you during that period would reduce the "Anchorage" reserve dedication by 200% of the amount of deliveries actually taken at the pipeline taps on the North Kenai Road. In this way we could live with our existing rate structure but would have compelling r ason to resolve the supply situation as soon as possible.

I hope that we can get together with Sam and Al here to work out the "exchange" for royalty gas as an operating problem in the event that is the course to be taken. In the event of getting a supply from you instead of royalty gas, I would like to have a meeting with you at the earliest available date in order to be ready at the January meeting of the Royalty Board (or sooner).

Season's greetings to you - it seems December just isn't my month to relax these days, remembering last year and the prior contract anniversary dates.

Cordially,

Dale Teel
President

DT/j

cc: Sam Sandusky

Enclosures

*Memorandum with Union as Operator (Draft Proposal)
*Memorandum with State of Alaska (Draft Proposal)
Letter of December 6 from Phillips Petroleum Company
Commissioner's Presentation to Royalty Board, December 10

*With transmittal letter dated December 7

ALASKA PIPELINE COMPANY

P. O. BOX 6286
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

December 12, 1975

DUPLICATE
ORIGINAL

Mr. Larry Bradford
Union Oil Company of California
P. O. Box 7600
Union Oil Center
Los Angeles, California 90017

Dear Larry:

The State of Alaska Oil and Gas Royalty Board has voted to authorize the Commissioner of Natural Resources (Guy Martin) to negotiate the sale of North Cook Inlet Gas Field royalty gas to us, subject to final approval at the Board's January meeting and then approval of the legislature.

I have sent Gene (Griffin—Union) informally copies of all correspondence, etc. in this matter except the enclosed preliminary drafts of proposed memoranda of agreement (APC with Union as operator, and APC with State); letters of support by City and Chugach; and the material I obtained at the Board meeting of December 10.

Board member (Dr.) Arlon Tussing (University of Alaska Economist) questioned whether or not we had diligently tried to get gas from "others," and I expect he will inquire further on this point at the January meeting. The vote was unanimous, with that reservation. Accordingly, I am writing now to ask whether or not Union would be willing to offer us our requirements up to 50 BCF over a period prior to June 1, 1984. Deliverability would be up to 15 MMCFD; take or pay at 10 MMCFD; delivery at any combination of the Kenai master meter and the three existing taps on your Kenai to Nikiski pipeline; at the price of 55.8¢ per MCF but not less than the highest price paid by any purchaser in the Cook Inlet area for a similar sale of gas of similar quality, adjusted yearly on the anniversary date of the contract, provided that we would have the option to terminate on one year's notice upon paying such higher price.

This same proposition was mentioned to John Horn of Phillips verbally, and his response was that since the royalty purchase (by others than us) would not be eliminated by such a decision, he would prefer to see us proceed to

SUBSIDIARY OF ALASKA INTERSTATE COMPANY

take the royalty. If you, or Marathon, would prefer to sell to us at these terms, from either of you individually or as equal partners, rather than for us to take this 50 BCF of North Cook royalty, I would like to discuss it further with you at the earliest opportunity. If you are not interested in this proposition, I would like to have it of record in order to have an answer for Dr. Tussing. Also, we would have to work out a short term and long term solution to a gas supply for the North Kenai Road area: we expect to be out of the present 10 BCF in April 1976, but even without delay or opposition we may not be lined up for North Cook Inlet gas before that date or maybe even six months after that date. I would propose for your consideration that we should "borrow" gas from the "Anchorage" contract, on the basis that we would repay through exchange from royalty gas in the ratio of 2 to 1, or, if we do not get gas to exchange, we would need to have one year's extension of the Nikiski contract at the present price etc., but agree that all deliveries we take from you during that period would reduce the "Anchorage" reserve dedication by 200% of the amount of deliveries actually taken at the pipeline taps on the North Kenai Road. In this way we could live with our existing rate structure but would have compelling reason to resolve the supply situation as soon as possible.

I hope that we can get together with Gene here to work out the "exchange" for royalty gas as an operating problem in the event that is the course to be taken. In the event of getting a supply from you instead of royalty gas, I would like to have a meeting with you at the earliest available date in order to be ready at the January meeting of the Royalty Board (or sooner).

Season's greetings to you - it seems December just isn't my month to relax these days, remembering last year and the prior contract anniversary dates.

Cordially,

Dale Teel
President

DT/j
cc; Gene Griffin

Enclosures

*Memorandum with Union as Operator (Draft Proposal)
*Memorandum with State of Alaska (Draft Proposal)
Letter of December 6 from Phillips Petroleum Company
Commissioner's Presentation to Royalty Board, December 10

*With transmittal letter dated December 7

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

December 12, 1975

Mr. Guy Martin
Commissioner of Natural Resources
State of Alaska
Juneau, Alaska

Dear Commissioner Martin:

I have revised pages 3 and 4 of the "Draft for Discussion Purposes," dated December 7 to reflect my understanding of the resolution of the Royalty Board on December 10, and to update the pricing which was given to me that day by Mr. John Horn of Phillips.

I will be available here until December 18 and expect to be back about January 2 (maybe December 29) and hope we can make some further progress either by telephone, mail, or a further meeting.

As you will see, I have copied Union, Marathon and Phillips in order to keep them apprised of developments in this matter.

Very truly yours,

Dale Teel
President

DT/j

cc: Bradford, Griffin (Union)
Emery, Sandusky (Marathon)
Horn, Swetnam (Phillips)

RECEIVED
DEC 16 1975
ALASKA ROYALTY
OIL & GAS BOARD

RECEIVED
DEC 15 1975
Department of
Natural Resources

4. It is of the essence of this Agreement that no regulatory jurisdiction of the Alaska Public Utilities Commission or other regulatory authority shall attach to Phillips or to Union as a consequence of the sale of the State royalty gas to APC under this Agreement, it being clearly understood that the utilization of "exchange" rather than literal transfer of the State royalty gas is done at the request of and for the convenience of the State and APC and not at the request of or for the benefit of either Union or Phillips. It is further understood and agreed that in the event this agreement is ever interpreted or used by the Alaska Public Utilities Commission or any other administrative or legislative or judicial body or agency, whether federal, state, or other, to assert and implement such regulatory jurisdiction, then this agreement shall terminate and become null and void.

5. At the date of the Agreement, the following are in effect with respect to royalty gas:

Price at wellhead:	50.25¢ per MCF	
Charge for delivery from North Cook Inlet Gas Field to Phillips LNG Plant on the North Kenai Road	5.55¢	Note: these prices are only estimates - subject to verification
Total	55.80¢ per MCF	

In the event a higher wellhead price than stated above is paid in the Cook Inlet Area (as defined in APC's contract with Union as amended effective December 18, 1974), by any purchaser for a similar sale of gas of similar quality, APC shall have the option (a) to meet such higher wellhead price as of the anniversary date of deliveries under this contract, and continue purchasing the royalty gas, or (b) to give the State one year's notice of termination of this Agreement, it being understood that during said notice period APC shall nevertheless continue to purchase whatever amount of royalty gas may be available to APC as described herein, at the higher price.

6. The Agreement shall be binding upon its execution and the approval of the legislature of the State of Alaska, but deliveries hereunder shall not commence until the date (a), all the gas reserves available to APC from Union by the terms of APC's

contract with Union dated May 1, 1967 have been purchased by APC or (b), May 1, 1977, whichever shall occur first.

Unless terminated as provided herein, this Agreement shall continue in effect until June 1, 1984.

_____
for Alaska Pipeline Company
Its_____

_____
For the State of Alaska
Its_____

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

December 7, 1975

RECEIVED
DEC 8 1975
ALASKA ROYALTY
OIL & GAS BOARD

Mr. Guy Martin, Commissioner
Department of Natural Resources
State of Alaska
Juneau, AK 99801

Dear Commissioner Martin:

Enclosed are 10 copies of my drafts of the elements of proposed general provisions which could be embodied in contracts for our purchase of State royalty gas from the North Cook Inlet Gas Field. I do not want to represent that these drafts have had legal consideration, but only that they indicate my ideas of the intent of contracts which would have to be negotiated.

I believe that we should and can hope that Union and Phillips will agree that the transaction as described offers great benefit to the majority of Alaskans without unreasonable or unfair impact on them.

We must hope that the general context and intent of these drafts can be endorsed by the State so that we can obtain a final decision in time to assure uninterrupted service to our customers on the North Kenai Road.

I will be arriving in Juneau Monday night and be available for discussion of our position on Tuesday and Wednesday.

Very truly yours,

Dale Teel
President

DT:jdh

Enclosures

cc: Each member of the Royalty Board
Alaska Public Utilities Commission
Municipality of Anchorage
Chugach Electric Association, Inc.

DRAFT FOR DISCUSSION PURPOSES ONLY, 12-7-75

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

NORTH COOK INLET STATE ROYALTY GAS
SALE TO ALASKA PIPELINE COMPANY
("Anchorage Natural Gas")

This memorandum ("Agreement") reflects the intent of the State of Alaska ("the State") and Alaska Pipeline Company ("APC") regarding APC's purchase of the State's 1/8th (one-eighth) royalty share of natural gas produced at the North Cook Inlet Gas Field, which is operated by Phillips Petroleum Company ("Phillips").

WHEREAS, APC has an early and urgent need to purchase additional natural gas for its customers in the vicinity of the North Kenai Road, and has applied to the State to acquire the State's 1/8th royalty share of gas produced by Phillips at the North Cook Inlet Gas Field to the extent any portion or all of such royalty gas may be available to APC without causing additional investment by Phillips or additional operating expense by Union Oil Company of California ("Union"), and

WHEREAS, Union as Operator of the Kenai Gas Field and the gas transmission line in the North Kenai Road now supplies APC's total requirements for natural gas at the Kenai Gas Field and at three (3) pipeline taps on the North Kenai Road and will continue to do so subject to terms and conditions of APC's various contracts and agreements with Union which contemplate or would allow APC's purchasing variable amounts of this royalty gas on an "if and as available" basis, and

WHEREAS, the royalty gas and the Kenai Field Gas are sufficiently similar that exchange rather than literal transfer of the royalty gas will be of advantage to all the parties concerned including APC's ultimate gas consumers and such exchange is entirely practical because of the Kenai Gas Field's inter connection with the North Cook Inlet Gas Field which has allowed exchanges to be made from time to time in the past, and

WHEREAS, the proposed sale of the royalty gas is seen to be in the public interest of the citizens of Alaska and the gas consumers served by APC (as evidenced by various statements which are of public record),

NOW THEREFORE, the State and APC agree as follows:

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

1. The State will report to APC each month the amount of royalty gas produced by Phillips during the prior month, together with a schedule showing the amount of such gas produced each day of the prior month.

2. Within one month following receipt of the data from the State (per paragraph (1) above), APC will obtain from Union an analysis of the amount of royalty gas which shall be deemed by all parties to have been sold to APC by the State, and APC shall pay therefor to the State within 30 days thereafter, at the price which otherwise would have been payable to the State by Phillips, and pay to Phillips the transportation charge thereon which otherwise would have been in effect received by Phillips for delivery of North Cook Inlet gas to the Phillips LNG plant on the North Kenai Road.

3. It is the intent of APC and the State that APC will pay the State for and will be deemed to have received from the State whatever quantity of gas (from 0% to 100% of the total quantity of royalty gas produced by Phillips) which Union shall determine to be appropriate in the circumstances and to be supportable by meter readings and calculations which Union and APC and the State will maintain on file, and available for release to any interested party on request. It is the further intent of the State and APC that the determination of how much of the State's total royalty share of natural gas produced from the North Cook Inlet Gas Field by Phillips can be deemed to have been sold to APC will be the responsibility of Union, as Operator of the Kenai Gas Field and the gas transmission line in the North Kenai Road.

   In making said determination, Union shall use reasonable discretion and judgment in balancing and accounting for gas supplied to APC from the Kenai Gas Field and from the North Cook Inlet Gas Field. No other responsibility shall derive to Union as a result of this Agreement, nor shall this Agreement be used to impose any obligation on Union which would cause increased operating expense to Union or to impose any obligation on Phillips which would require Phillips to add investment for transmission (or compression) without compensation therefor which is reasonable and acceptable to Phillips. In the event such investment becomes necessary for Phillips, APC would have the option either (a) to participate equitably in that investment, or (b) to agree to compensate Phillips at an agreed price per MCF or per month, or (c) to terminate its taking of royalty gas within one year of the date when these options are presented to APC for decision.

4. It is of the essence of this Agreement that no regulatory jurisdiction of the Alaska Public Utilities Commission or other regulatory authority shall attach to Phillips or to Union as a consequence of the sale of the State royalty gas to APC under this Agreement, it being clearly understood that the utilization of "exchange" rather than literal transfer of the State royalty gas is done at the request of and for the convenience of the State and APC and not at the request of or for the benefit of either Union or Phillips. It is further understood and agreed that in the event this agreement is ever interpreted or used by the Alaska Public Utilities Commission or any other administrative or legislative or judicial body or agency, whether federal, state, or other, to assert and implement such regulatory jurisdiction, then this agreement shall terminate and become null and void.

5. At the date of the Agreement, the following are in effect with respect to royalty gas:

Price at wellhead:	45¢ per MCF	
		Note: these prices are only estimates--subject to verification
Charge for delivery from North Cook Inlet Gas Field to Phillips LNG Plant on the North Kenai Road	5.45¢	
Total	50.45¢ per MCF	

In the event Phillips may offer the State a higher wellhead price than stated above, as a result of repricing of gas exported as liquid (LNG) to Japan, APC shall have the option (a) to meet such higher wellhead price and continue purchasing the royalty gas, or (b) to give the State one year's notice of termination of this Agreement, it being understood that during said notice period APC shall nevertheless continue to purchase whatever amount of royalty gas may be available to APC as described herein, at the higher price offered by Phillips.

In the event Phillips' export of North Cook Inlet gas as LNG to Japan is terminated and Phillips continues to produce gas at the North Kenai Gas Field for any other disposition, then the price of royalty gas sold to APC hereunder shall be not less than the average price during the year prior to the termination, nor less than the average price paid by APC for gas it purchased from others during the prior year (which after December 31, 1985 will be the "area price" as defined in APC's contract with Union as amended effective December 18, 1974).

6. The Agreement shall be binding upon its execution and the approval of the legislature of the State of Alaska, but deliveries hereunder shall not commence until the date (a), all the gas reserves available to APC from Union by the terms of APC's contract with Union dated May 1, 1967 have been purchased by APC or (b), May 1, 1977.

Unless terminated as provided herein, this Agreement shall continue in effect until the end of commercial production of natural gas from the North Cook Inlet Gas Field or the end of commercial production of natural gas from the Kenai Gas Field, whichever shall occur first.

_____

For Alaska Pipeline Company
Its _____

_____

For the State of Alaska
Its _____

PRELIMINARY DRAFT FOR
DISCUSSION PURPOSES ONLY

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

MEMORANDUM OF UNDERSTANDING

This memorandum reflects the intent of Union Oil Company of California ("Union") as Operator of the Kenai Gas Field and a gas transmission line in the North Kenai Road for the interest of both Union and Marathon Oil Company ("Marathon") with respect to the natural gas requirements of Alaska Pipeline Company ("APC") at the Kenai Gas Field and from three (3) pipeline taps in the North Kenai Road. Union-Marathon have supplied this service under contracts as amended from time to time, since the first advent of natural gas service in Alaska in 1961. The parties recognize that APC has applied for and expects to purchase the State of Alaska's 1/8th (one-eighth) royalty share of gas produced at the North Cook Inlet Gas Field by Phillips Petroleum Company, which is brought to the North Kenai Road by Phillips' pipeline for liquefaction and export to Japan. Since Phillips' pipeline is interconnected with Union-Marathon's pipeline at or near the North Kenai Road, and since the composition of North Cook Inlet gas is virtually identical to Kenai field gas, the sale of this royalty gas can in effect be accomplished by "exchanges" such that literal delivery of this gas need not be made.

Existing meters can be utilized to account for the amount of North Cook Inlet gas field production and thus the amount of royalty gas; together with data from other meters, displacement or "exchanges" can be postulated by accounting rather than any additional metering or literal physical transfer of North Cook Inlet gas to APC.

Union as Operator is agreeable to providing an analysis of data furnished to Union by the State of Alaska (or Phillips) and by APC and from Union's various meters, and calculating the net result of the displacement or "exchanges" which APC's purchase of State royalty gas will entail.

Union will analyze the data furnished to them each month and advise the various parties (Marathon, Phillips, State of Alaska, U.S.G.S., and APC) of the amount of North Cook Inlet gas which is to be deemed by all parties to have been taken by APC from the State of Alaska for payment purposes. Union, as Operator of the Kenai gas field, will advise these parties and will calculate the net quantity of gas which is to be deemed to have been taken from the Kenai gas field.

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

The parties understand and agree that neither this memorandum nor any other aspect of APC's purchasing State royalty gas shall incur for Union any responsibility whatsoever, other than the derivation and calculation of the amount of State royalty gas for which APC is to make payment to the State of Alaska.

As Operator of the Kenai Gas Field and the Kenai North Road gas transmission line, Union will continue delivering gas to APC at the Kenai gas field and at the three (3) pipeline taps now existing, and will rely on APC to cause the State of Alaska (Phillips) to operate as necessary so that no additional deliverability (demand) is imposed, above the contractual amount of 160,000 MCF per day plus the excess, if any, of State royalty gas above the amount of gas taken by APC at the three pipeline taps on the North Kenai Road. As Operator, Union would be free to work out whatever production scheduling it deems appropriate, directly with Phillips, so that no additional operating expense will accrue to Union; however, Union will not impose any unreasonable schedule on Phillips.

At such times as Phillips may be unable to meet the production scheduling desired by Union, then APC agrees to accept whatever production scheduling may be mutually satisfactory to Union and Phillips; and if no such production scheduling can be agreed upon or cannot be made by Phillips, then and to that extent neither Phillips nor Union shall become liable in consequence. It is the good faith of APC and Union that APC will receive the State royalty gas only to the extent it may be available without additional investment for transmission (or compression) by Phillips or Union, provided however, that in the event royalty gas available to APC is less than 10,000 MCF per day, then Union will provide the difference for a period of not less than one year. APC would expect to have the option, in the event investment is necessary for Phillips to continue delivering State royalty gas, to participate equitably in that investment, or to pay a mutually acceptable price per MCF or per month therefor, or to terminate its taking of the State royalty gas.

APC will pay to Union, for its services as Operator in this arrangement, the amount of ___ per MCF of State royalty gas purchased hereby, but not less than ___ per month, plus the price Union may elect to apply to any gas taken at the three pipeline taps and not returned by exchange within one year of such delivery.

DT/js

Alaska Gas and Service Company

GENERAL OFFICES LOCATED AT 3000 SPENARD ROAD
P.O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-5551
TELEX 25-187

RECEIVED
DEC 4 1975
Department of
Natural Resources

December 2, 1975

Alaska Public Utilities Commission
1100 MacKay Building
338 Denali Street
Anchorage, 99501

Gentlemen: Filing of Special Contract
with
Chugach Electric Association

Our filings for permanent and revised interim rates did not include Rate PI, which theretofore was in effect only for the Bernice Lake power plant of Chugach Electric Association. As contemplated in those filings, Rate PI has been extinguished. Service to this power plant is now made by a special contract which reflects the same price and general terms which are contained in the special contract for service to the municipality's power plants in Anchorage -- that contract having been approved by Order of the Commission on August 30, 1974 (Docket U-74-83). Copy of the special contract with Chugach is enclosed for the Commission's information and file, since by its terms it is subject to acceptance by the Commission.

Our stipulation with Alaska Legal Services and the Order of the Superior Court dated November 12, 1975 anticipated the extinguishment of Rate PI and the establishment of revised interim rates (special contract provisions) for service to power plants, and the special contract with Chugach is consistent with that stipulation and Order.

Our testimony to the Commission on October 30 and 31 in Docket U-75-68 (requesting reinstatement of our flow through provisions tariff Sections 708 and 709) also anticipated the extinguishment of Rate PI and the negotiation of this special contract for service to Chugach's Bernice Lake power plant.

Alaska Gas and Service Company
GENERAL OFFICES LOCATED AT 3000 SPENARD ROAD
P.O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-5551
TELEX 25-197

This special contract is also consistent with and was anticipated in our informal discussions with various members of the Commission and its staff in connection with our proposed purchase of State royalty gas from the North Cook gas field. Our presentations to the State of Alaska Oil and Gas Royalty Board of October 10 and November 10 in support of this proposal also anticipated this special contract with Chugach and the extinguishment of Rate PI. We believe that our application to purchase this royalty gas may be considered or decided by the Royalty Board on December 10, as to policy rather than detailed or final action. This special contract and our tariff Section 708 are key elements for that transaction.

We believe that both the municipality and Chugach will affirmatively support our application for the royalty gas, and we would also hope that the Commission will do so also, prior to the December 10 meeting.

For all the reasons given, we request that the Commission should give emergency attention to and acceptance of the enclosed special contract with Chugach and to the reinstatement of Section 708 of our tariffs, so that our position to the Royalty Board will be clearly established prior to the meeting of December 10.

Very truly yours,

Dale Teel

Dale Teel
President

DT/js

cc: Mr. L. J. Schultz, General Manager
Chugach Electric Association
Mr. Roger Kemppel, Attorney
Municipality of Anchorage
Mr. Guy Martin ✓
Commissioner of Natural Resources

STATE of ALASKA

MEMORANDUM

ROUGH DRAFT

TO: Guy R. Martin
Commissioner

DATE : November 19, 1975

FROM: William C. Fackler
Deputy Commissioner

SUBJECT: Analysis of North Cook Inlet Royalty Gas Proposal by Alaska Natural Gas

Anchorage Natural Gas (ANG) proposes that State take North Cook Inlet Field gas royalty in-kind and sell to ANG at same rate as State now receives in royalty payments from Phillips.

Daily volume dependent on LNG plant use but ANG used average of 15 mmcf/d, total of 75 bcf for contract over 15 year period as basis for proposal.

Reference ANG brochure "Summary" page 1.

1. ANG will take delivery immediately on " if and as available" basis and pay price State now receives.

This statement is apparently based on assumption that ANG will simply replace State and receive gas at LNG plant gate with payment to State at present royalty rate of 50.45 cents per MCF at the plant gate. This price includes a 5.45¢ per MCF transport charge from platform to LNG plant.

There are two problem areas.

a. Transport of ANG gas for resale from platform to shore might be construed as qualifying the pipeline for APUC jurisdiction. If so, PPCO would probably object. Also 5.45¢ per M transport charge

AGO 801829

might be reviewed for applicability under current costs.

b. It is doubtful that the State would contract with ANG at a fixed price for 15 years. Contract terms should provide for price equal to highest price paid in area for gas of similar quality to assure that State is not receiving less than they would otherwise receive. Present royalty value on North Cook Inlet gas field is highest value received for gas by State.

2. ANG would use North Cook Inlet gas throughout system. Since present Nikiski contract was for total volume of 10 bcf over ten year period ending May 1, 1977, it is apparent that new amount desired (75 bcf) is basically an addition to reserves and not for North Kenai Road customers. Bernice Lake paid $.657 mmbtu in 1972 (1974 Alaska Power Survey p. 52) almost 4 times the fuel cost of Beluga power generation. Chugach Electric Association owns both facilities and has been operating Bernice Lake at capacity until the Knik Arm submarine cable between Beluga and Anchorage is repaired. Probably Bernice Lake station will be reduced to standby or peak load power source. Since

Bernice Lake uses 90% of the Nikiski gas contract this will greatly reduce the depletion of that gas supply.

ANG summary does not list price paid for Nikiski contract gas. If price is similar to that of Anchorage contract gas, Bernice Lake indicated cost of 65.7¢ per MMBTU allows a healthy margin for ANG for the short distance involved.

3. ANG purchase of North Cook Inlet royalty will benefit ANG customers to the extent that it will increase remaining reserves committed to ANG. The price will be higher than present price paid to Union Marathon for Anchorage contract gas and will raise the price to the consumer by that increment.* The benefit to CEA (Chugach Electric) customers seems doubtful since CEA Beluga contract is at a 16¢ MMBTU rate which is 1/4 of the rate charged by ANG at Bernice Lake. 64¢

* Unless, of course, you now use price we was already suggested by APC in their letter/memo of August 20, 1975

ANG asserts that the North Cook Inlet royalty gas at present royalty price would be a lower cost than the other alternatives explored by ANG, the alternative prices are not available for comparison.

III. Proposed Price, Escalation, Total Volume, Annual Volume, Contract Term, Deliverability and Transportation.

a. Price and Escalations

"ANG proposes to pay to the State the same price which the State would have otherwise received from Phillips export of the North Cook Inlet royalty gas to Japan for the duration of that export and thereafter not less than"

Price paid to State should not be less than

(1) price which the State would have otherwise received from Phillips export of the North Cook Inlet royalty gas to Japan including any future escalations in price received by Phillips.

(2) the highest price paid in the area by any buyer to any seller of gas of similar quality.

b. Total Volume, Annual Volume, Contract Term, Deliverability

ANG does not require specific deliverability. Proposes to purchase 1/8th of the production of the North Cook Inlet gas field, day by day and year by year or "if and as deliverable".

Contract term, total volume and annual volume depend on Phillips production from the North Cook Inlet gas field and the State should not specify amounts. Term should not be open end however. Phillips contract with Tokyo Gas & Tokyo Electric expires 6-1-84 unless extended. Contract term for State should not exceed terms of Phillips' contract, also should include proviso to protect State if Phillips production is terminated for any [redacted]son. Consider a 10 yr term for 50 bcf?

AGO 801832

c. Transportation

ANG proposes that transportation of royalty gas from platform to LNG plant site be done by Phillips for the present charge of 5.45¢ per MCF. ANG expects to contribute its proportionate share of additional transportation cost or compression cost with option of contributing capital or higher transport charge.

Phillips has raised the issue of APUC classifying gas pipeline as a utility if it transports gas for a third party for resale. Phillips indicated they would not transport gas if this situation arose.

It seems doubtful that the State could transfer the present transport situation with Phillips to another party without Phillips consent. The State lease provides that when the Lessor elects to take its royalty in-kind, Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon). Further, the transport charge itself may be open to negotiation between Phillips and ANG.

In the event that the State does contract with ANG for the purchase of its royalty gas, the point of taking and transportation charges could become key issues. The possibility of selling the State's royalty gas to ANG with the result of higher transport charges reducing the net value to the State should be avoided.

ANCHORAGE NATURAL GAS

Anchorage Natural Gas has an immediate problem coupled with a potential long range problem.

A. The immediate problem is Anchorage Natural Gas's ten billion cubic feet per year Nikiski contract gas will be used up within a few months and they have not been able to find another source for this eight million cubic feet per day demand. (Bernice Power Plant services the liquid natural gas and ammonia plants plus other areas; they are the major user.)

* They have tried to contract for 75 billion cubic feet (15 million cubic feet per day) over 15 years with no luck.

B. The long range problem is the need to have more committed gas reserves for future consumer needs and to avoid financial problems that will result from a shortage of gas.

Solutions

SHORT RANGE PROBLEM (Need gas now)

Obtain State's royalty gas from the north Cook Inlet gas field. Twelve and one half percent of the average yearly production from this field would be about 5.5 billion cubic feet per year or approximately 75 billion cubic feet over 15 years. This would give Anchorage Natural Gas up to 15 million cubic feet per day, enough to satisfy the eight million cubic feet per day for Kenai and a surplus for building up reserves.*

*

LONG RANGE PROBLEM (Need more gas reserves for future)

1. Obtain more reserves by exploration. They have undertaken this, but so far have a dry hole at $ 500,000 cost. their share.

2. Obtain reserves by using royalty gas and extending the reserves in their existing contracts. They are proposing this. Present proposal will only add 1 yr at best - no solution to long range. ANG will have to make new contract for large amount similar to present contract and price will certainly be higher.

*The north Cook Inlet field is the only source they can tap since their contract for the Kenai field (with Union-Marathon) stipulates if royalty gas is used it will reduce the existing 550 billion cubic feet contract.

PROS AND CONS OF THE

ANCHORAGE NATURAL GAS PROPOSAL

Pro

1. If Anchorage Natural Gas does not acquire gas for its Nikiski contract loss, Bernice Power Plant will probably switch to oil with higher costs to consumers and added environmental problems with oil burning. Royalty gas to Anchorage Natural Gas would help hold costs down and ease potential environmental problems.*

2. Royalty gas will help Anchorage Natural Gas's long range gas reserves. They will only need eight million cubic feet per day for the Kenai problem and can apply the other seven million to strengthen the overall reserve problem.

3. After a precedent is set, additional royalty gas may become available to strengthen the long term reserve picture for Anchorage Natural Gas.

4. Committing royalty gas at reasonable prices will help keep our consumers from paying future high energy costs resulting from outside shortages.

5. This decision should encourage additional exploration for Gas reserves in the Cook Inlet.

Con

The petroleum industry does not like it. It may create an economic hardship upon Phillips Petroleum Company by taking some of their feedstocks to the Kenai Liquid Natural Gas Plant. It will also set a precedent. The oil industry will not be able to assume that it has 100% of gas reserves to cost for long term projects.

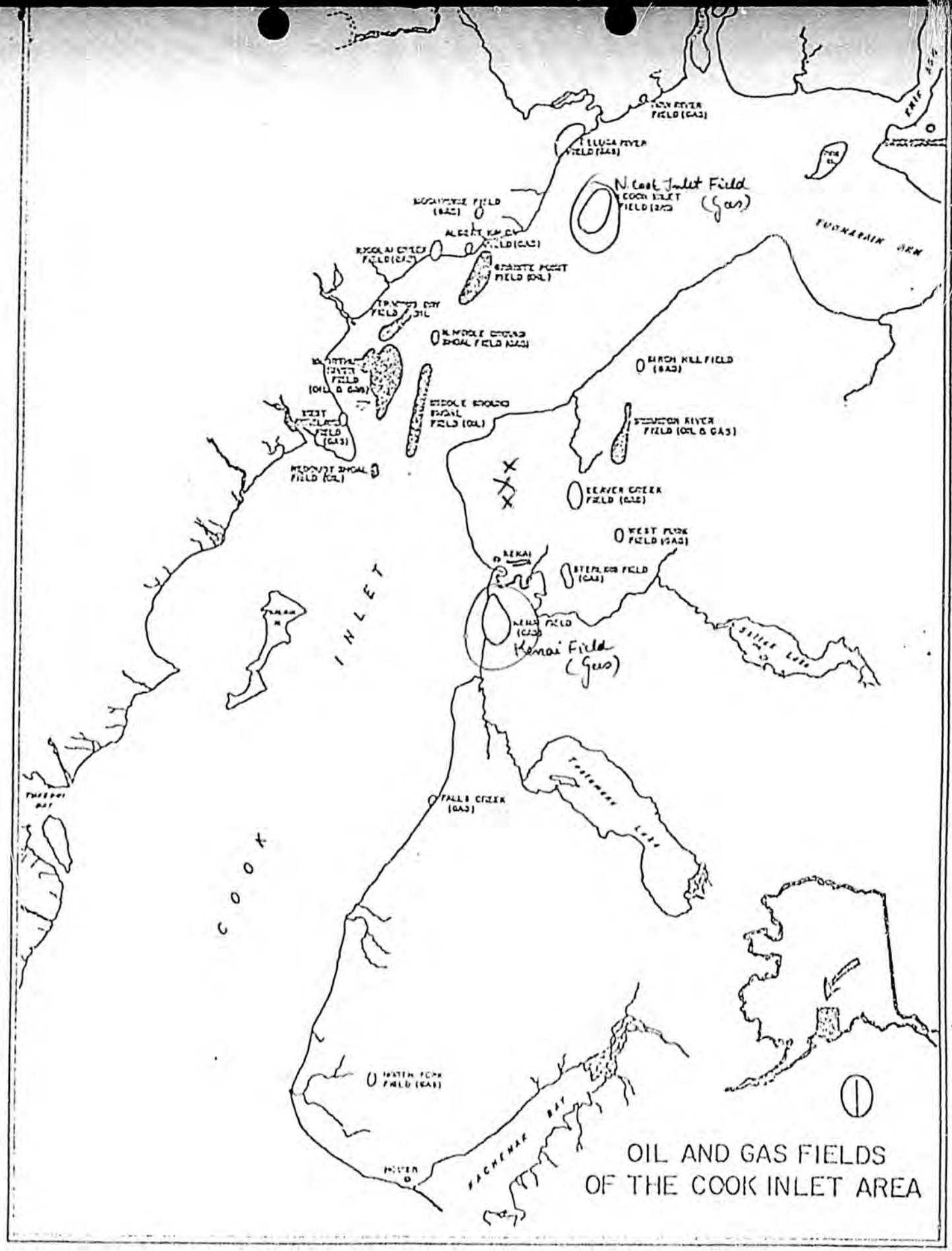
*If Anchorage Natural Gas faces a long term gas shortage problem, they may have to cut off the military--switching them to oil?

SUMMARY

Operational problems of Anchorage Natural Gas are going to directly effect the Alaskan consumer since it is a major supplier of energy to the public. Our public gas suppliers, such as Anchorage Natural Gas, need adequate gas supplies for as long a period as possible. It is disturbing to find that present dedicated reserves will not last over 15 years and the Alaskan consumer may be forced into paying competitive California prices for its own gas, or not being able to obtain the gas since it could all be committed to other states.

ANG is a profit making corporation well able to make additional contracts for increased supply of gas as they have in the past. This play is economic and not desperate need for reserves. The Alaskan consumer will have to pay competitive prices for additional gas unless subsidized by State through royalty gas prices or regulatory control similar to past experience with FPC (low prices vs gas)

AGO 801836


N. Cook Inlet Field
(Gas)
Kenai Field
(Gas)
COOK INLET
KENAI
NIKISKI
TYONEK
ANCHORAGE
KNIK ARM
TURNAGAIN ARM
BEAVER CREEK FIELD (GAS)
WEST FORK FIELD (GAS)
STERLING FIELD (GAS)
FALLS CREEK (GAS)
NORTH FORK FIELD (GAS)
MIDDLE GROUND SHOAL FIELD (OIL)
MCARTHUR RIVER FIELD (OIL & GAS)
MEDVEJI SHOAL FIELD (OIL)
BIRCH HILL FIELD (GAS)
BELUGA RIVER FIELD (GAS)
KNIK RIVER FIELD (GAS)
TRADING BAY FIELD (OIL)
GRANITE POINT FIELD (OIL)
ALBERT KALOA FIELD (GAS)
MCARTHUR RIVER FIELD (OIL & GAS)
KASILOF
HOMER
KACHEMAK BAY
FORELAND
FIELD (GAS)
OIL AND GAS FIELDS
OF THE COOK INLET AREA

AGO 801837

The Case for Committing
Alaska State Royalty Gas
from the North Cook Inlet
gas field to Alaska Pipeline
Company ("Anchorage Natural
Gas")

Presented to the Royalty Board
on November 10, 1975

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Introduction

Alaska Pipeline Company and its distribution affiliate Alaska Gas and Service Company, Division of Alaska Interstate Company, collectively known as "Anchorage Natural Gas" have requested to purchase the State's 1/8 royalty share of the North Cook Inlet gas field, which is operated by Phillips Petroleum Company. In response, Anchorage Natural Gas has been requested to appear on November 10, 1975 to discuss this matter with the Royalty Board. This memorandum is submitted as advance information to the Royalty Board and for their convenience in considering the matter.

Summary

Anchorage Natural Gas (ANG) is the most logical choice of any potential purchaser of North Cook Inlet royalty gas, because:

1. ANG is prepared to accept delivery of this gas immediately, on an "if and as available" basis, and at the same price the State now receives for this gas while it is being liquefied and shipped to Japan.

   Assuming that delivery to ANG can be made by "exchange," there would be no necessity for capital expenditure for new pipelines or other facilities at present.

2. ANG would utilize this gas as part of its gas supply for its entire service area, from Kalifonsky to Eklutna, and thereby be able to provide improved assurance of the availability of natural gas to all its customers, and at lower cost to ratepayers than is possible through any other alternative known to ANG.

3. Without this gas, ANG may not be able to continue serving the Bernice Lake power plant of Chugach Electric Association, or, if an alternate source is found, then the cost to ANG's customers is likely to be very substantially more than would apply to purchase of State royalty gas. Thus, ANG's purchase of State royalty gas will be of material benefit to ANG's residential and commercial gas customers, and of even greater benefit to Chugach Electric Association and all its customers from Homer to Talkeetna. More than 50% of Alaska's population would be affected, either as gas consumers or as power customers, and thus nearly all of Alaska's taxpayers would be benefited.

   For the reasons given, ANG requests the Royalty Board to give ANG highest priority as a prospective purchaser of State royalty gas from the North Cook Inlet gas field, and to recommend such an arrangement for priority action in the next legislative session. Export of this gas, whether to Japan or elsewhere, is not in the best interest of Alaska's citizens.

I. ANG's Need for Additional Gas Reserves

ANG has two gas supply contracts at present. First, the "Anchorage" contract has committed a total of 550 BCF (billion cubic feet) from January 1, 1972 through December 31, 1992, delivered at a master meter in the Kenai gas field. This contract provides 160 million cubic feet per day of deliverability through 1985, and thereafter a deliverability of 1-1/3 times the "average daily" reserves remaining. The price for this gas is:

22¢ per MCF through December 31, 1975
24¢ per MCF 1/1/76 through 12/31/80
27¢ per MCF 1/1/81 through 12/31/85
* "Area Price" 1/1/86 through end of contract

(1)

* Area Price is related to sales to third parties in the vicinity of Cook Inlet, as defined by the contract.

In addition to the foregoing contractual price schedules, ANG pays 19.5¢ per MCF for deliverability of 160 million cubic feet per day, escalated each January 1 by the ratio of the Wholesale Price Index (WPI) for November 1975 divided by the WPI of November 1974. Thus, effective January 1, 1976 ANG will pay 24¢ plus 19.5¢ plus the (estimated 1¢) WPI escalation or 44.5¢ per MCF, for a deliverability of 160 million cfd and take-or-pay of 72 million per day (annual average).

ANG's second gas contract (both are with Union and Marathon as equal partners) is called the "Nikiski" contract. It provided 10 million cfd of deliverability, 10 BCF of reserves, and was for 10 years ending May 1, 1977. Delivery is at ANG's choice of three pipeline taps on Union-Marathon's 20" pipeline between the Kenai gas field and the industrial area on the North Kenai Road. At the current level of sales, the 10 BCF of reserves will be exhausted in 1976, prior to the end of the contract term. ANG has several hundred residential and commercial customers on the North Kenai Road, but by far the greater share (90% or more) of this gas is sold to the Bernice Lake power plant of Chugach Electric Association.

(2)

Because of the impending early exhaustion of the "Nikiski" contract reserves, and because of the need to obtain additional reserves for the "Anchorage" area, ANG wrote to Union, Marathon, Phillips, and Shell to inquire for a total of 75 BCF over a 15 year period. The only written response was from Shell, who said they had no uncommitted gas available for sale to ANG. Phillips responded in a telephone conversation that since the North Cook Inlet gas was in part potentially committed to

Northwest Natural (Portland) and since both Portland and Pacific Lighting (Los Angeles) were "negotiating" for the State royalty from this field, Phillips could not offer any to us. No response has been received from Union or Marathon other than an informal reaction that 75 BCF is an unreasonably large amount of reserves for us to request in the circumstances.

The information that the gas companies in Portland and Los Angeles are attempting to obtain the State royalty gas from the North Cook Inlet gas field accentuated ANG's interest in the royalty gas and its approaches to the Alaska Department of Natural Resources which has led to this presentation.

ANG's information is that a wellhead value of 45¢ per MCF applies to Phillips' purchase of State royalty gas for its LNG export to Japan. This price is net of 5.45¢ per MCF transportation cost from the platform to the LNG plant, so that a price of 50.45¢ per MCF is in effect for gas delivered at the LNG plant. This is the price ANG contemplates paying for royalty gas from the North Cook Inlet gas field.

ANG has made several other efforts to obtain additional gas reserves. First, it has tried to purchase surplus gas which is now committed to the gas company at the City of Kenai, with no indication of interest in response. Second, ANG inquired to purchase gas now being flared at the Swanson River oil field as a safety measure. This was declined as being "temporary." Third, ANG is negotiating to purchase gas from a well which is controlled by Mike Halbouty ("West Fork"). The deliverability and reserves from this well are probably negligible in relation to ANG's requirements, however.

ANG is aware of the "going price" for intrastate gas sales in areas such as Texas, and has hoped that it could avoid such pricing and make the best possible purchase by applying for the North Cook Inlet royalty gas, as it has done.

Quite apart from the urgent need for gas to replace the "Nikiski" contract, ANG must maintain a supply of reserves related to the term outstanding on its long term financing. When the reserve life falls below the financing term remaining, ANG will have to pre-pay installments on this long term debt, as it had to do in 1970-71 prior to obtaining the current reserve commitment.

The tables and graphs attached present the historical trends and the range of future gas sales. It is clear that if present trends continue, ANG will face pre-payment in 1980 and thereafter unless additional supplies can be secured. It is with that fact in mind that ANG has formed a subsidiary corporation, Gas Supply Corporation of Alaska ("GASCOA"), to explore for natural gas in the vicinity of Anchorage. ANG has invested more than $500,000 to date in this activity, and has drilled (with others) an exploratory well on acreage at the mouth of the Big Susitna River. Although this well was plugged and abandoned, it did not condemn the area, and further exploration is contemplated as time and financing permit.

ANG cannot be complacent about its future need for gas, even without considering the exhaustion of its "Nikiski" contract reserve commitment. But that urgent problem requires early and positive action, because the gas supply there will last less than a year. The North Cook Inlet royalty gas is seen to be the ideal and only realistic solution to that immediate problem, and helpful to ANG's long term reserves needs as well.

II. Reasons for Requesting North Cook Inlet Royalty Gas

North Cook Inlet royalty gas is interchangeable with Kenai gas field gas, as may be seen by the fact that the two streams are blended (in a 70/30 ratio) as feedstock to the Phillips-Marathon LNG plant on the North Kenai Road. Both fields are essentially pure methane. All the necessary pipeline systems exist to allow an "exchange" to be made so that ANG could "receive" the royalty gas at the Kenai gas field. Such exchanges already are being made by the operators (Phillips, Marathon, Union). ANG can easily agree to "take" whatever royalty gas may be produced at the North Cook Inlet gas field, day by day, without requiring any investment by either of these operators. At the times such deliveries from the North Cook Inlet gas field might be limited temporarily by production facilities or by pipeline facilities, ANG could "work within" (exchange correspondingly less) that limitation, day by day. Alternatively, ANG could readily agree to take the full 1/8th royalty share each and every day if that were preferred by the operators (Phillips, Marathon, Union). When pipeline facilities from the North Cook Inlet may permanently limit its capacity to deliver the royalty gas, ANG could participate in the cost of compressors or additional pipeline necessary to maintain the delivery.

While the "exchange" described above is the only rational and reasonable method of implementing ANG's purchase of royalty gas, ANG could, if necessary, construct a pipeline to deliver the royalty gas into its pipeline to Anchorage. Obviously it would appear to be unnecessary and ludicrous for ANG to be hauling royalty gas south along the North Kenai Road while Union-Marathon is hauling identical gas north along the same road. Thus the "exchange" would be in the public interest, and in the mutual best concern of all the operators.

No other royalty gas is so readily available or really available at all, to ANG. Royalty at the Kenai gas field cannot be taken by ANG to advantage, since this was considered and such limitations are contained in ANG's contract at the Kenai gas field. If ANG does not take North Cook Inlet royalty gas it will be exported to Japan or to Portland or to Los Angeles. ANG's use of this gas to serve its Alaskan gas customers cannot be regarded as being less appropriate than these export arrangements, provided ANG pays no less than exporting the gas would have paid.

III. Proposed Price, Escalations, Total Volume, Annual Volume, Contract Term, Deliverability, and Transportation

(a) Price and Escalations

ANG proposes to pay to the State the same price which the State otherwise would have received from (Phillips') export of the North Cook Inlet royalty gas to Japan, for the duration of that export and thereafter not less than

(1) the average price in effect during the last full year prior to termination of the export contract, and not less than

(2) the price in effect, from year to year, for gas purchased by ANG at the Kenai gas field (from Union-Marathon)

(b) Total Volume, Annual Volume, Contract Term, Deliverability

ANG proposes to purchase 1/8th of the production of the North Cook Inlet gas field, day by day and year by year. ANG understands that at current production rates, approximately 15,000 MCF per day, or 5.5 BCF/year, would be available. AGAS would not, however, require any particular amount by day or by month or by year or in total. ANG contemplates that its commitment to purchase North Cook Inlet royalty gas would be for the life of production and probably at least 15 years, so that about 75 BCF would be available. ANG also understands that at present the maximum daily royalty production is about 20,000 MCF, related to a condition in which North Cook Inlet gas is supplying the entire input to the LNG plant, which would be unusual and temporary, since the contractual arrangement is for 70% North Cook Inlet gas and 30% Kenai gas to the plant.

ANG has adequate deliverability under contract at the Kenai gas field, and contractual ability to interrupt, so that it does not require a deliverability feature to be part of an agreement to purchase royalty gas -- ANG can take royalty gas on an "if and as available" basis. If, for the convenience of the operators (Phillips or Marathon or Union), a specified daily quantity should be desired, such as 15,000 to 20,000 MCF per day, ANG could so agree.

(c) Transportation

ANG proposes that transportation of the royalty gas would be by Phillips, to the LNG plant site, at the present amount which is understood to be 5.45¢ per MCF. ANG understands that as field pressure will decline during the life of the field, compression will become necessary and will cause additional cost for transportation. ANG further recognizes that compression may also become necessary as a result of increased throughput at the LNG plant whether as a result of increased plant loading or as a result of expansion of the LNG plant. ANG would expect to contribute its proportionate share of such additional transportation cost either by participating in the necessary investment or by compensating Phillips appropriately if Phillips makes the entire investment. ANG proposes that it should have the option of making the capital contribution or paying a higher transportation charge, to assure that Phillips is fairly compensated, without controversy.

IV Question of (hypothetical) "possible subsidization of Anchorage gas consumers at state taxpayers' expense" (Raised in Mr. Fackler's letter of October 15, 1975)

ANG believes that its offer, to pay the same price the State would otherwise receive from Phillips on the sale of the royalty gas for export to Japan, precludes any suggestion of "subsidization," particularly in view of ANG's further proposal to pay not less than the "area price" in the event the export to Japan is terminated. ANG further believes that it would not be in the public interest for Anchorage gas consumers to sustain a higher price for this royalty gas than would be payable on its export to Japan, although ANG understands that competitive bidding might result in a higher price than the price for export to Japan.

ANG contemplates that if the State were to deny ANG's offer to purchase the North Cook Inlet royalty gas on the terms described above, and to invite competitive bidding for this gas in the hope of realizing a higher price, severe complications might arise which would delay or prevent the consummation of such a sale. As an example, Phillips-Marathon have been attempting to sell their gas from this field to the gas company in Portland, Oregon for several years, but have not resolved the matter of jurisdiction by the Federal Power Commission (FPC) since the sale involves interstate commerce.

A sale of royalty gas in interstate commerce would have the same regulatory character, and involve the same jurisdiction by the FPC. A sale to ANG, however, does not involve the FPC in any way, being intrastate.

Aside from the regulatory problem, there easily could be other problems with an interstate sale, such as the need for additional drilling to "prove" the reserves or deliverability; additional pipeline facilities to assure delivery to the LNG plant; and possibly additional LNG storage facilities. All of these problems could require negotiation by the several parties (Phillips, Marathon, State, and the high bidder). Investment for new facilities would require time for engineering and design - which would not be required for ANG's purchase of the gas for pipelining to Anchorage and use by the Bernice Lake power plant and ANG's other customers on the North Kenai Road.

ANG believes that the possible benefits of a higher price through competitive bidding would be more than outweighed by the timeliness and appropriateness of ANG's purchasing this gas for use in Alaska, by the avoidance of regulatory problems (FPC), and by the relatively simple negotiation which ANG's proposal would entail. ANG believes that the suggestion of "subsidization" is illusory and that in fact ANG's proposal will be beneficial to all Alaskan taxpayers as well as Anchorage gas consumers, in that ANG's proposal can be implemented immediately upon approval by the Royalty Board and the legislature, if the parties can agree as described. This would result in increased production of natural gas and thus more income to the State, at the earliest possible date.

LIST OF COPIES OF CORRESPONDENCE

1. August 1, 1975 Letter to Chugach
2. August 1 Letters to Union, Marathon, Phillips, Shell
3. August 20 Letter to O.K. Gilbreth
4. August 25 Letter and Memo of August 22 to Alaska Public Utilities Commission
5. September 4 Letter from Shell Oil Company
6. September 24 Memorandum to Commissioner Martin
7. September 29 Letter to Standard Oil of California
8. September 30 Letter to Commissioner Martin
9. October 10 Letter from Standard Oil of California
10. October 15 Letter from W.C. Fackler (Invitation to Royalty Board Meeting, Nov. 10)

Alaska Gas and Service Company

GENERAL OFFICES LOCATED AT 3000 SPENARD ROAD
P. O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-5551
TELEX 25-187

August 1, 1975

Chugach Electric Association, Inc.
8th and Gambell
Anchorage, Alaska 99501

Gentlemen:

It has just come to my attention this week that our supply of gas which we deliver to you at the Bernice Lake power plant is diminishing at a rate which is cause for serious concern and requires the earliest and best possible attention. Although our contract for the supply runs to May 1, 1977, your continuing heavy use of this plant this year may exhaust the remaining reserves during this coming winter. Based on your purchases to June 30 this year, we have well less than a one year supply remaining under contract. We assume that when you activate the new land line to Wasilla and complete your cable repairs, your requirement to operate Bernice Lake will be substantially reduced, but in the event this does not occur we could have a critical situation (as to a contractual supply only--not physical) this winter. At any rate there is an early requirement for us to make new arrangements for this supply and we wanted you to be so advised so that you could consider the availability of oil which you used during the years of operating this plant prior to its use of gas.

We have notified our suppliers regarding this matter and hopefully they may be able to expedite their consideration at least for a short term solution. As you know, however, at the moment we are operating without "flow through" provisions and in fact without a definite rate structure. It may be that we will be unable to consummate agreement for additional gas, even for a short term, until these matters are resolved. We have appealed to the APUC for reinstatement of the "flow through" provisions, and informally for a permanent rate structure, hoping for a favorable decision. We would then proceed immediately on the matter of reserves to supply Bernice Lake. But we may have to consider other action, even interruptions, due to regulatory or legal developments. We will, of course, keep you advised on this matter, and we regret that we have not had time in recent months to review such important matters with our staff continually.

Very truly yours,

Dale Teel
President

DT:lkd

AGO 801851

Alaska Public Utilities Commission

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

August 1, 1975

Union Oil Company of California
P.O. Box 7600, Union Oil Center
Los Angeles, California

Attention: Mr. Larry Bradford

Gentlemen:

Our contract for gas on the "Kenai North Road" will expire May 1, 1977 and it appears that the remaining reserves may have been purchased prior to that date, possibly early in the year, 1976.

We would ask for your proposal to commit additional reserves, considering our requirement to be up to 15 million cubic feet per day, and 75 BCF over a 15 year period to commence upon usage of our remaining reserves or not later than May 1, 1977.

Because of the limited time available, we would ask for a response at your earliest opportunity.

Very truly yours,

Original Signed by
DALE TEEL

Dale Teel
President

DT:lkd

cc: Mr. Bart Emery, Marathon, Findlay, Ohio

AGO 801852

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

August 1, 1975

Marathon Oil Company
539 South Main Street
Findlay, Ohio

Attention: Mr. Bart Emery

Gentlemen:

Our contract for gas on the "Kenai North Road" will expire May 1, 1977, and it appears that the remaining reserves may have been purchased prior to that date, possibly early in the year 1976.

We would ask for your proposal to commit additional reserves, considering our requirement to be up to 15 million cubic feet per day, and 75 BCF over a 15 year period to commence upon usage of our remaining reserves or not later than May 1, 1977.

Because of the limited time available, we would ask for a response at your earliest opportunity.

Very truly yours,

Original Signed by
DALE TEEL

Dale Teel
President

DT:lkd

cc: Mr. Larry Bradford, Union Oil, Los Angeles

AGO 801853

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

August 1, 1975

Phillips Petroleum Company
Phillips Building
Bartlesville, Oklahoma 66600

Attention: Mr. John Horn

Gentlemen:

Our contract for gas on the "Kenai North Road" will expire May 1, 1977, and it appears that the remaining reserves may have been purchased prior to that date, possibly early in the year 1976.

We would ask for your proposal to commit additional reserves, considering out requirement to be up to 15 million cubic feet per day, and 75 BCF over a 15 year period to commence upon usage of our remaining reserves or not later than May 1, 1977.

Because of the limited time available, we would ask for a response at your earliest opportunity.

Very truly yours,

Original Signed by
DALE TEEL

Dale Teel
President

DT:lkd

AGO 801854

ALASKA PIPELINE COMPANY
P. O. BOX 6288
ANCHORAGE, ALASKA 99502
3000 SPENARD ROAD
PHONE (907) 277-5551

August 1, 1975

Shell Oil Company
Alaska Mutual Savings Bank Building
Anchorage, Alaska

Attention: Mr. Tom Cates

Gentlemen:

Our contract for gas on the "Kenai North Road" will expire May 1, 1977, and it appears that the remaining reserves may have been purchased prior to that date, possibly early in the year 1976.

We would ask for your proposal to commit additional reserves, considering our requirement to be up to 15 million cubic feet per day, and 75 BCF over a 15 year period to commence upon usage of our remaining reserves or not later than May 1, 1977.

Because of the limited time available, we would ask for a response at your earliest opportunity.

Very truly yours,
Original Signed by
DALE TEEL

Dale Teel
President

DT:lkd

AGO 801855

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

August 20, 1975

Mr. O. K. Gilbreth, Director
Division of Oil and Gas
State of Alaska
Department of Natural Resources
3001 Porcupine Street
Anchorage, Alaska 99504

Dear Easy:

We have a gas supply contract with Union-Marathon for 10 BCF on the Kenai North Road which expires May 1, 1977. Due to accelerated sales to Chugach Electric's Bernice Lake power plant this year, it appears the entire reserve quantity could be used up within less than one year from now, and we are soliciting a replacement supply of gas to serve Chugach and our other customers on the Kenai North Road.

We are in a position to commit to take more than our North Road requirements, however, and would like to offer to purchase the State's royalty share of Phillips' production from North Cook Inlet, delivered to a metering point near the Phillips-Marathon LNG plant on the Kenai North Road. The excess above our Kenai North Road sales would be used to displace deliveries by Union-Marathon to us at the Kenai gas field, and thus serve to prolong the adequacy of our reserve commitment at the Kenai gas field. We are not certain as to whether or not the displacement can be made "on paper," or whether we would be required to lay a pipeline to connect into our Anchorage pipeline either at or near the Kenai gas field or at or near our compressor station east of the Kenai River.

Please consider this letter to be an application to purchase royalty gas as described, pursuant to AS 38.06.010. Since limited time is available to do any necessary construction, we hope all procedural requirements can be determined readily. We would anticipate paying the State the same price it would have received from Phillips, which we believe to be 45¢ per MCF plus 5.45¢ transportation fee, as compared to the current 41.5¢ cost of gas (and deliverability) at the Kenai gas field.

We are relying on approval by the Alaska Public Utilities Commission for us to "flow through" the increased cost of gas to Chugach's Bernice Lake power plant and to "meld" the (higher) cost royalty gas with the (lower) cost Kenai field gas, on a day-to-day basis, since the amount of royalty gas we would receive would depend on the rate of production of the Phillips-Marathon LNG plant and be outside our control. When this plant is down for any reason, we would be utilizing Kenai field gas as replacement.

Please advise regarding any questions or further procedure we should follow in presenting a formal offer to the State.

Very truly yours,

Dale Teel
President

DT:lkd

cc: Alaska Public Utilities Commission

Alaska Gas and Service Company

GENERAL OFFICES LOCATED AT 3000 SPENARD ROAD
P. O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-5551
TELEX 25-187

August 25, 1975

Alaska Public Utilities Commission
1100 MacKay Building
338 Denali Street
Anchorage, Alaska 99501

Gentlemen:

The enclosed "Memo to File" (August 22, 1975) was prepared for discussion with the APUC or staff, in connection with our filing for reinstatement of our tariff section "708," (purchased gas cost adjustment). It illustrates the effect this section would have on various gas rates in the event we were successful in obtaining the state royalty gas which we have proposed to buy.

Also enclosed are a map of the Upper Cook Inlet and copies of our letters of August 1 and August 13 to Phillips. It is intended that the enclosures are for the information of the APUC and staff, but would not become "public" information at present.

Very truly yours,

Dale Teel
President

DT:lv
Enclosures

AGO 801858

Teel Alono

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

August 22, 1975

Memo To: File

Subject: Intended Applicability and Operation of AGAS Tariff Section 708 Purchased Gas Cost Adjustment

AGAS now has a filing at the APUC for reinstatement of its Section 708, modified to the apparent (verbal) satisfaction of the APUC staff (Dwight MacCurdy and Bob Lindblom). AGAS is relying on approval of this filing at the earliest possible date because of its imperative need to be contracting for additional gas reserves, both for continued service to customers on the North Kenai Road (especially Chugach's Bernice Lake power plant) and to avoid (postpone) future problems with the provisions of AGAS' long term financing. AGAS' reserves to serve North Kenai Road customers could be exhausted during the winter of 1975-1976 if Chugach continues its current rate of consumption. Unless an alternate solution is developed, AGAS must require Chugach to interrupt the use of gas beginning in October 1975, through March 1976, to the maximum allowable by tariff (Schedule PI), which is 10 days per calendar month during those months.

AGAS' preferred solution is to apply for and obtain state royalty gas from Phillips' North Cook Inlet gas field, rather than to face the (unknown) price of new reserves from its present supplier (Union-Marathon) and rather than to consume, on the North Kenai Road, the reserves dedicated for the Anchorage area. Accordingly AGAS has offered the State the price of 45.0¢ plus 5.45¢ or 50.45¢ per MCF for royalty gas which the State in effect is now selling to Phillips and Phillips in turn is exporting to Japan. To do so, AGAS would expect to build about 35 miles of 8" pipeline at the earliest opportunity, along the Homer Electric power-line right-of-way, from the Phillips LNG plant to the AGAS (APC) Gudenrath compressor station. This pipeline initially could flow in reverse, supplying gas to North Kenai Road customers out of AGAS' (APC's) pipeline to Anchorage, but as soon as royalty gas becomes available, gas would flow from the North Kenai Road to the AGAS Anchorage pipeline. The amount of royalty gas is assumed to be 1/8 x 70% x 140 million cfd or 12.25 million cfd. Normally it is expected to run at a fairly steady rate, somewhat higher than 12.25, but it could go as high as 17 million, or as low as zero when the LNG plant is shut down. Thus the taking of royalty gas would introduce new dynamics into AGAS' transmission system. Similarly, as a result of these dynamics, AGAS' cost of purchased gas will be constantly varying and thus its rates to customers also will be constantly varying, depending on the mix of Kenai field gas and State royalty gas obtaining for a given month.

AGAS' tariff Section 708-Purchased Gas Cost Adjustment-was designed with the intent of application to such changing costs of gas: each month AGAS would determine its cost of gas for the prior month and would adjust its effective rates upward or downward to reflect the variation from the base price, which will be 43.5¢ after January 1, 1976.

Applying Section 708 in this way, the following examples are given:

1. Assume a summer load condition as follows:

Anchorage/Soldotna Market:	50,000,000 cf/day
North Kenai Road Market:	8,000,000 cf/day
State Royalty gas:	15,000,000 cf/day

Thus the cost of gas for this condition would be

15,000 MCF x 50.45¢ or	$ 7,567.50
plus (58 - 15 = 43) 43,000 MCF x 43.5¢ or	18,705.00
Total	$26,272.50
Average cost of 58,000 MCF is	45.297¢/MCF

After 1/1/76, all rates are based on gas cost of 43.5¢ (includes 2¢ escalation of 1/1/76, per paragraph 9, page 17 of Order No. 4, U-75-30). The average cost of gas above (45.30¢) less this base price of 43.5¢, is 1.8¢ effective increase which would "flow through" to all AGAS customers per tariffs and contracts. Thus, using the illustrated average rates given on page 19 of APUC Order No. 4, and adding the 2.0¢ escalation of 1/1/76, the "flow through" effect of applying Section 708 as described would be:

Schedule A:	157.08 plus 2.0 is 159.08; plus 1.8 is 160.88; 1.1%
B:	142.48 plus 2.0 is 144.48; plus 1.8 is 146.28; 1.2%
C:	102.58 plus 2.0 is 104.58; plus 1.8 is 106.38; 1.7%
*Chugach I-5:	73.78 plus 2.0 is 75.78; plus 1.8 is 77.58; 2.4%
**Chugach PI :	51.78 plus 2.0 is 53.78; plus 1.8 is 55.58; 3.3%
City Contract:	53.48 plus 2.0 is 55.48; plus 1.8 is 57.28; 3.2%
Military:	60.20 plus 2.0 is 62.20; plus 1.8 is 64.00; 2.9%

2. Assume an average winter load condition as follows:

Anchorage/Soldotna Market:	90,000,000 cf/day
1/ North Kenai Road Market:	10,000,000 cf/day
2/ State Royalty gas:	10,000,000 cf/day

Thus the cost of gas for this condition would be

10,000 MCF x 50.45¢ or	$ 5,045.00
plus (100 - 10 = 90) 90,000 MCF x 43.5¢ or	39,150.00
Total	$44,195.00

Average cost of 100,000 MCF would be 44.195¢/MCF (say 44.20¢)
and rates would be 0.7¢/MCF increase over the base of 43.5¢/MCF.

As for Condition "1" described above, the effect of 0.7¢ per MCF increase would be as follows:

Schedule A:	159.08 plus 0.7 is 159.78; 0.44%
B:	144.48 plus 0.7 is 145.18; 0.48%
C:	104.58 plus 0.7 is 105.28; 0.67%
I-5:	75.78 plus 0.7 is 76.48; 0.92%
PI:	53.78 plus 0.7 is 54.48; 1.30%
City:	55.48 plus 0.7 is 56.18; 1.25%
Military:	62.20 plus 0.7 is 62.90; 1.13%

1/ The North Road Market is mostly Chugach's Bernice Lake power plant, thus there will not be much increase for winter over summer.

2/ The LNG plant operation is typically less in winter than summer due to slower passage of the LNG ships to/from Japan.

3. Assume a peak winter condition as follows:

Anchorage/Soldotna Market:	150,000,000 cf/day
North Kenai Road Market:	12,000,000 cf/day
State Royalty gas:	15,000,000 cf/day

Thus the cost of gas for this condition would be

15,000 MCF x 50.45¢ or	$ 7,567.50
plus (162 - 15 = 147) 147,000 MCF x 43.5¢ or	63,945.00
Total	$71,512.50

Average cost of 162,000 MCF is 44.144¢, and rates would be increased 0.644¢ over the base of 43.5¢ per MCF. Effect on rates almost same as Condition "2" above.

4. Assume a summer condition such that LNG plant is at maximum operation, but Chugach Bernice Lake plant is shut down for repairs or other reason, and thus essentially all the State royalty gas would be entering the Anchorage system:

Anchorage/Soldotna Market:	40,000,000 cf/day
North Kenai Road Market:	2,000,000 cf/day
State Royalty gas:	17,000,000 cf/day

Thus the cost of gas for this condition would be

17,000 MCF x 50.45¢ or	$ 8,576.50
plus (42 - 17 = 25) 25,000 MCF x 43.5¢ or	10,875.00
Total	$19,451.50

Average cost of 42,000 MCF is 46.313¢, and rates would be 2.813¢ (say 2.80¢) over the base of 43.5¢ per MCF.

The effect on AGAS rates for this condition would be:

Schedule A:	159.08 plus 2.80¢ is	161.88;	1.76%
B:	144.48 plus 2.80¢ is	147.28;	1.94%
C:	104.58 plus 2.80¢ is	107.38;	2.68%
I-5:	75.78 plus 2.80¢ is	78.58;	3.69%
PI:	53.78 plus 2.80¢ is	56.58;	5.21%
City:	55.48 plus 2.80¢ is	58.28;	5.05%
Military:	62.20 plus 2.80¢ is	65.00;	4.50%

Condition "4" above is about the worst probable effect of royalty gas on AGAS' rates. Clearly the effect of such "worst conditions" is not such as to raise doubts as to the acceptability of applying AGAS' Section 708 to melding of State royalty gas with Kenai field gas. Only with Section 708 in effect can this melding be accomplished, and thus this Section is essential to AGAS' utilizing royalty gas (or any other new gas supply).

While the foregoing discussion indicates that APC would expect to construct a pipeline from the LNG plant site to the site of APC's Gudenrath compressor station, the more logical step would be to accomplish the "delivery" of the royalty gas by "paper exchanges" rather than physical transportation of the gas. Both North Cook Inlet gas and Kenai field gas are essentially pure (99% plus) methane and no adjustment for heating value or other quality aspect is necessary as a result of such "paper exchanges." The term "paper exchange" here means that with the consent and cooperation of all the parties involved, AGAS (APC) could pay to the State as if it were actually accepting royalty gas from the State, but in fact would continue to receive gas only as at present, at its Kalifonsky metering point, and on the North Kenai Road, produced at the Kenai gas field. The effect would be that AGAS would deduct from actual deliveries at the Kenai field meter an amount of gas equal to the royalty production for a month and would pay the Kenai gas field producers for the remainder. AGAS (APC) would continue to receive gas from these producers at the Kenai North Road at presently existing taps on their pipeline, and would add these deliveries to the "net" deliveries at the Kenai gas field for purposes of computing APC's "purchases" each month from the Kenai gas field. Then Marathon and Union Phillips could resolve the balancing of their records as follows:

- The amount of Phillips' royalty production (12.5% of Phillips' total) for a given period, probably on monthly scheduling, would displace Marathon's actual delivery to the LNG plant, and Phillips would increase its otherwise "share" (70% of plant input) to compensate, during the following month, or later in the year if preferred by the parties for their convenience.

Obviously, there would be a requirement for additional production (wells in operation) and transmission by Phillips, unless for economic reasons the additional productive capacity were to be installed at the Kenai gas field with appropriate cost reimbursement being made by Phillips to Union-Marathon.

Because of the anticipated complexities of having all the parties--Marathon, Union, Phillips, State of Alaska, and AGAS (APC) affirmatively cooperate in the above "paper exchange," this memo has presumed that a new pipeline and physical movement of the gas would be necessary. Hopefully there can be a negotiation to eliminate the need for such a pipeline, however.

From the total actual "takes," at the Kenai field meter plus the taps on Union- Marathon's pipeline on the Kenai North Road, would be deducted each year, the Phillips' royalty in order to determine the net usage of Kenai field gas against the contractural total of 550 million MCF. Guaranteed deliverability, now contracted at 160,000 MCF per day, would not be improved by the "paper exchange" alternative to a pipeline, while such a pipeline could improve deliverability, but only to the extent of royalty gas being available when needed, which would be coincidental and not within our control. However, this indefinite and debated improvement on deliverability resulting from the new pipeline would not alone justify the cost of the pipeline.

SHELL OIL COMPANY
601 W. 5TH AVENUE, SUITE 810
ANCHORAGE, ALASKA 99501

September 4, 1975

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

Subject Middle Ground Shoal Field
Associated Gas Reserves

Attention Mr. Dale Teel

Gentlemen:

Thank you for your letter of August 1, 1975, inquiring into the possibility of the purchase of gas at our North Kenai Road onshore facility. Unfortunately, our gas is committed on a long term basis to another buyer in the area and, therefore, we are not in a position to consider your proposal.

Should we be so fortunate as to develop new reserves in the Anchorage Basin, we would gladly entertain your proposition.

Very truly yours,

T. S. Cate
Land Representative

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

MEMORANDUM

TO: Mr. Guy Martin
Commissioner of Natural Resources

FROM: Dale Teel

DATE: September 24, 1975

SUBJECT: Alaska Pipeline Company's Request to Purchase State Royalty Gas from the North Cook Inlet Gas Field ("Phillips")

Alaska Pipeline Company (APC) and its affiliate Alaska Gas and Service Company ("Anchorage Natural Gas") supply natural gas to 285 customers on the North Kenai Road and to the Bernice Lake power plant of Chugach Electric Association. The gas is obtained from the industrial pipeline which supplies the LNG plant, the Ammonia/Urea plant, and gas for reinjection into the Swanson River Oil field, and comes from the Kenai gas field (Union-Marathon), under a contract which runs to May 1, 1977. Due to unexpectedly heavy usage by the Bernice Lake power plant, the reserve quantity, 10 billion cubic feet (BCF), will be used prior to May 1, 1977, and at that point the contract will terminate. A contract extension and additional commitment of reserves has been requested of Union-Marathon, or the right to receive gas on the North Kenai Road which is committed for the Anchorage area under a separate contract. There has been little if any progress made on these requests thus far.

Alaska Pipeline Company's contract with Union-Marathon has a provision that if APC were to obtain royalty gas from the Kenai gas field, then the commitment of gas reserves by Union-Marathon (originally 550 BCF) would be reduced an equal amount, and thus in effect APC is barred from negotiating for royalty gas from the Kenai gas field.

APC has inquired for a commitment of gas from Phillips, with the (telephone) response that since Phillips' obligations to the gas company of Portland, Oregon are in suspense due to hearings at the Federal Power Commission and since the gas company at Los Angeles is attempting to purchase royalty gas from the North Cook Inlet gas field, Phillips is not clear to negotiate a commitment of reserves to APC. It is known also that the Portland gas company is requesting to purchase North Cook Inlet royalty gas (discussions with Governor Hammond).

APC has written to the State (letter to O.K. Gilbreth, August 20, 1975, attached) requesting to purchase the North Cook Inlet royalty gas at the price of 50.45¢ per MCF, which is the price which now applies to the royalty gas which Phillips utilizes for its LNG manufacture, which is known to be 45¢ wellhead plus 5.45¢ transportation. If this gas were to be offered to APC, APC could build a pipeline from the LNG plant to deliver the gas into its pipeline to Anchorage as well as to supply its North Kenai Road customers. Such a pipeline (approximately 35 miles of 8") could be built in the right of way now occupied by Homer Electric Association's power line from the Bernice Lake power plant to "Quartz Creek." However, construction of such a pipeline should not be necessary, because existing pipeline systems could be utilized to "exchange," or "displace," gas and the transaction could be made entirely on paper, continuing actual movement as at present, without change. North Cook Inlet gas is identical to Kenai field gas (the streams are interchangeable at the LNG plant), so adjustments can be made by volume only.

APC would appear to be the ideal customer for State royalty gas because it would "blend" (by price/rate adjustments) the higher priced royalty gas into its present supply, with relatively small impact on its rates to Alaskan gas users. APC has negotiated "deliverability" with Union-Marathon so that it is in a position to take none or the full royalty share of North Cook Inlet gas without placing its suppliers (Union-Marathon) in any hardship and without having to rely on constant or steady rate production from the North Cook Inlet field. In other words, APC could take the State royalty gas from North Cook Inlet if and as it is produced, without requiring "deliverability."

The foregoing description assumes that the producers (Union, Marathon, Phillips) and the State can readily agree to the "exchange" or "displacement" as indicated. If APC were to build the new pipeline so that the royalty gas actually were to be moved from the LNG plant to APC's pipeline to Anchorage, the same general situation would obtain as for displacement, but operation would be relatively complex since gas would have to move to or from the LNG plant in the new pipeline depending on whether or not the LNG plant were running and at what rate. It is anticipated that normally there would be adequate notice available so that flow rate and directional changes would be practical - in fact displacement could be utilized even with such a pipeline, to foster best scheduling by all the parties. Such displacement actually occurs already, from time to time, although it involves only the producers (Union, Marathon, Phillips) and, of course, does not affect APC or the State at present. The proposed displacement, either with or without a new pipeline being added, should be just as practical if the parties would so agree.

DT/js
enclosure

AGD 801866

cc: Alaska Public Utilities Commission

DALE TEEL
PRESIDENT

ALASKA PIPELINE COMPANY
P. O. BOX 5288
ANCHORAGE, ALASKA 99502

September 29, 1975

Mr. John Rowland
Standard Oil Company of California
3001 C Street
Anchorage, Alaska

Dear John:

I want to thank you for the courtesies extended to me Saturday, September 27, by Walt Larman at your Swanson River compressor plant. I met Ed Saltz there also, and renewed an acquaintance of 10 years or more ago, when he was assisting us in restoring gas service after the 1964 earthquake.

Naturally, I can't avoid thinking about possible uses for the gas now being flared as a safety measure at the plant. I can visualize various possibilities such as piping it into our pipeline to Anchorage, or to Soldotna, or to the North Kenai Road. We have a centrifugal compression unit at Mile 25 on our pipeline which might be adapted to handle this gas especially during the summer season, when it is not needed for capacity, and we have available an electric motor-driven reciprocating unit which could be installed at your plant. We need the gas and might be able to justify the 20 miles of pipeline if the gas were available "free," or nearly so, even without a commitment of deliverability or a reserves quantity -- in other words, "if and as available." I would like to continue discussion of this possibility with you at your convenience.

Cordially,

DT/js

AGO 801867

T Chron

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

September 30, 1975

Mr. Guy Martin
Commissioner of Natural Resources
State of Alaska
Juneau, Alaska

Dear Mr. Martin:

Confirming our discussion at the Anchorage airport on September 30, and my letter to Mr. Gilbreth of August 20, and memorandum to you of September 24, Alaska Pipeline Company is requesting to purchase the royalty share of North Cook Inlet gas field at or near the Phillips-Marathon LNG plant on the North Kenai Road, at the price used by Phillips to acquire this gas from the State for the manufacture of LNG for export to Japan or elsewhere. We believe the most reasonable method for handling the delivery and sale would be by "exchange," or "displacement," so that construction of new pipeline(s) and compression would be minimized. Since our supply at the Kenai gas field is interconnected to the North Cook Inlet gas supply at the LNG plant, for the time being it should be practical that we would take whatever amount of the North Cook Inlet royalty gas may be available day by day by displacement into our system at the Kenai gas field. Later, when additional investment would be required for transporting this royalty gas to shore, we could negotiate our participation in investment, or install our own facilities if necessary, in order to accomplish the purchase on the most reasonable basis for all concerned.

The essential aspect of our request is that we have an immediate need for additional gas on the North Kenai Road and we have a long term requirement for additional gas reserves to serve Alaskan customers in our present service area. We believe that it is in the public interest that we should be allowed to purchase this State royalty gas for local consumption rather than for this gas to be exported to Japan or elsewhere. We will begin preparing a formal

AGO 801868 A

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

application to purchase this gas and will appreciate having your guidance as to what supporting data or format may be desired, if any, for presentation to the Royalty Board or to the legislature to satisfy statutes or regulations which apply.

Very truly yours,

Dale Teel

DT/js

cc: O. K. Gilbreth, Director
Division of Oil and Gas

Alaska Public Utilities Commission

ADL 801868-B

Chevron

Standard Oil Company of California,
Western Operations, Inc.
P.O. Box 7-839, Anchorage, AK 99510 • Phone (907) 279-9666

J. L. Rowland
Area Supervisor
Producing Department

October 10, 1975

Mr. Dale Teel, President
Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

Dear Dale:

Thanks for your letter of September 29, and for your interest in our flared gas at Swanson River.

Since speaking with you, I have reviewed our gas handling capacity with our Engineering group and have determined the gas ~~phase~~ is still considered temporary. As you know, we have made several adjustments in the past year, including the installation of ~~ten~~ field compressors, and we are actively pursuing other remedies which will relieve our flaring problem.

It is my opinion that the laying of a 20 mile pipeline, based on the limited volumes which we foresee, would be a very high risk venture.

We do appreciate your asking about the possibilities and we'll certainly be alert to those opportunities which may become available.

Very truly yours,

J. L. Rowland

JLR:mld

AGO 801869

STATE OF ALASKA

JAY S. HAMMOND, Governor

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER / POUCH M — JUNEAU 99801

October 15, 1975

Mr. Dale Teel
Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

Dear Mr. Teel:

Your letter and memorandum regarding the proposal of Alaska Pipeline Company to purchase state royalty gas from the North Cook Inlet Gas Field was read into the minutes of the October 12 meeting of the Royalty Board.

The Royalty Board invites you to attend the next meeting which will be November 10, 1975, in the Alaska Division of Lands Conference Room in Anchorage beginning at 8:30 a.m. to discuss your proposal.

Items to be addressed in your presentation should be the need for additional gas reserves, reasons for requesting North Cook Inlet source of gas, price and schedule of escalation, total volume, annual volume, deliverability, term of proposal, transportation and so forth. A question has been raised as to the possibility that this proposal would be a subsidization of Anchorage gas consumers at state taxpayer's expense. You might wish to anticipate this point also in your discussion.

Please advise me if I can be of further assistance.

Very truly yours,

William C. Fackler

William C. Fackler
Deputy Commissioner

cc: Mr. Robert H. Reynolds
921 East Sixth Avenue
Anchorage, Alaska 99501

AGO 801870

LIST OF TABLES AND GRAPHS

1. Table of gas consumption
   Actual, 1971-1975 (estimated)
   Projected, 1976-1985 (growth at 1, or 2, BCFY)

2. Graph of data per Table (1)

3. Table of remaining reserves
   Actual, 1971-1975 (estimated)
   Projected, 1976-1985 (growth at 1, or 2, BCFY)

4. Graph of data per Table (3)

5. Table of life of remaining reserves
   Actual, 1971-1975 (estimated)
   Projected, 1976-1985 (growth at 1, or 2, BCFY)

   Note: This is the quotient of reserves data in Table (3) divided by consumption during the prior year per Table (1)

6. Graph of data per Table (5)

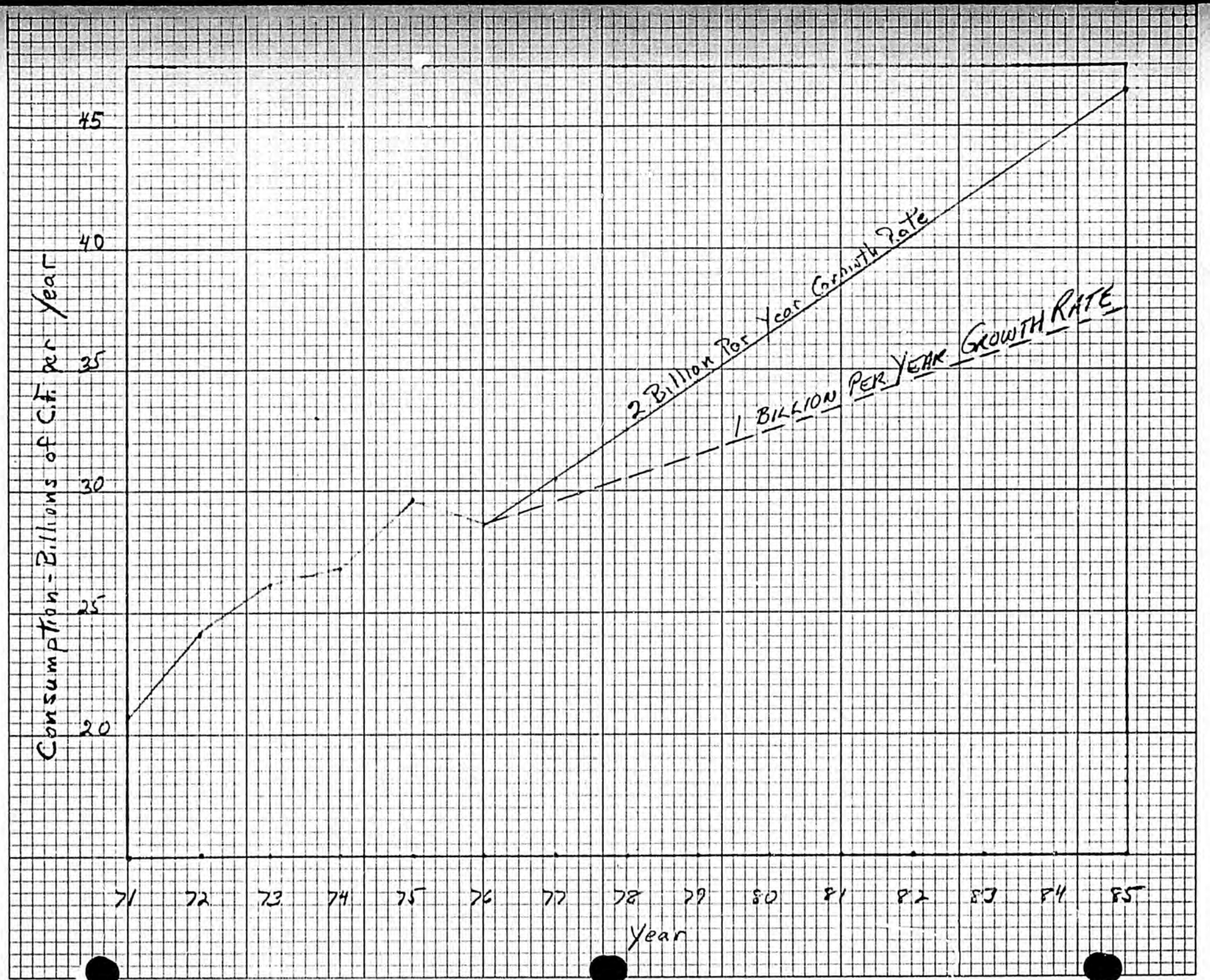
7. Graph of North Cook Inlet gas production since 1969

ALASKA GAS AND SERVICE - ALASKA PIPELINE COMPANY

Table of Gas Consumption BCF

	Year	Consumption (One Billion/yr Growth Rate)	Consumption (Two Billion/yr Growth Rate)
	1971	20.6	20.6
	1972	24.1	24.1
	1973	26.1	26.1
	1974	26.7	26.7
	1975	29.7	29.7
*	1976	28.5	28.5
	1977	29.5	30.5
	1978	30.5	32.5
	1979	31.5	34.5
	1980	32.5	36.5
	1981	33.5	38.5
	1982	34.5	40.5
	1983	35.5	42.5
	1984	36.5	44.5
	1985	37.5	46.5

*Reflects loss of deliveries to Chugach Electric 11/4/75


Consumption - Billions of Cft. per Year
45
40
35
30
25
20
2 Billion Per Year Growth Rate
1 BILLION PER YEAR GROWTH RATE
71
72
73
74
75
76
77
78
79
80
81
82
83
84
85
Year

AGO 801873

ALASKA GAS AND SERVICE - ALASKA PIPELINE COMPANY

Table of Remaining Reserves

Year End	Reserves-MCF (One Billion CF/yr Growth Rate)	Reserves-MCF (Two Billion cf/yr Growth Rate)
1971	559	559
1972	535	535
1973	509	509
1974	482	482
1975	452	452
1976	424	424
1977	394	393
1978	363	361
1979	332	326
1980	300	290
1981	266	251
1982	232	211
1983	196	168
1984	160	124
1985	122	77

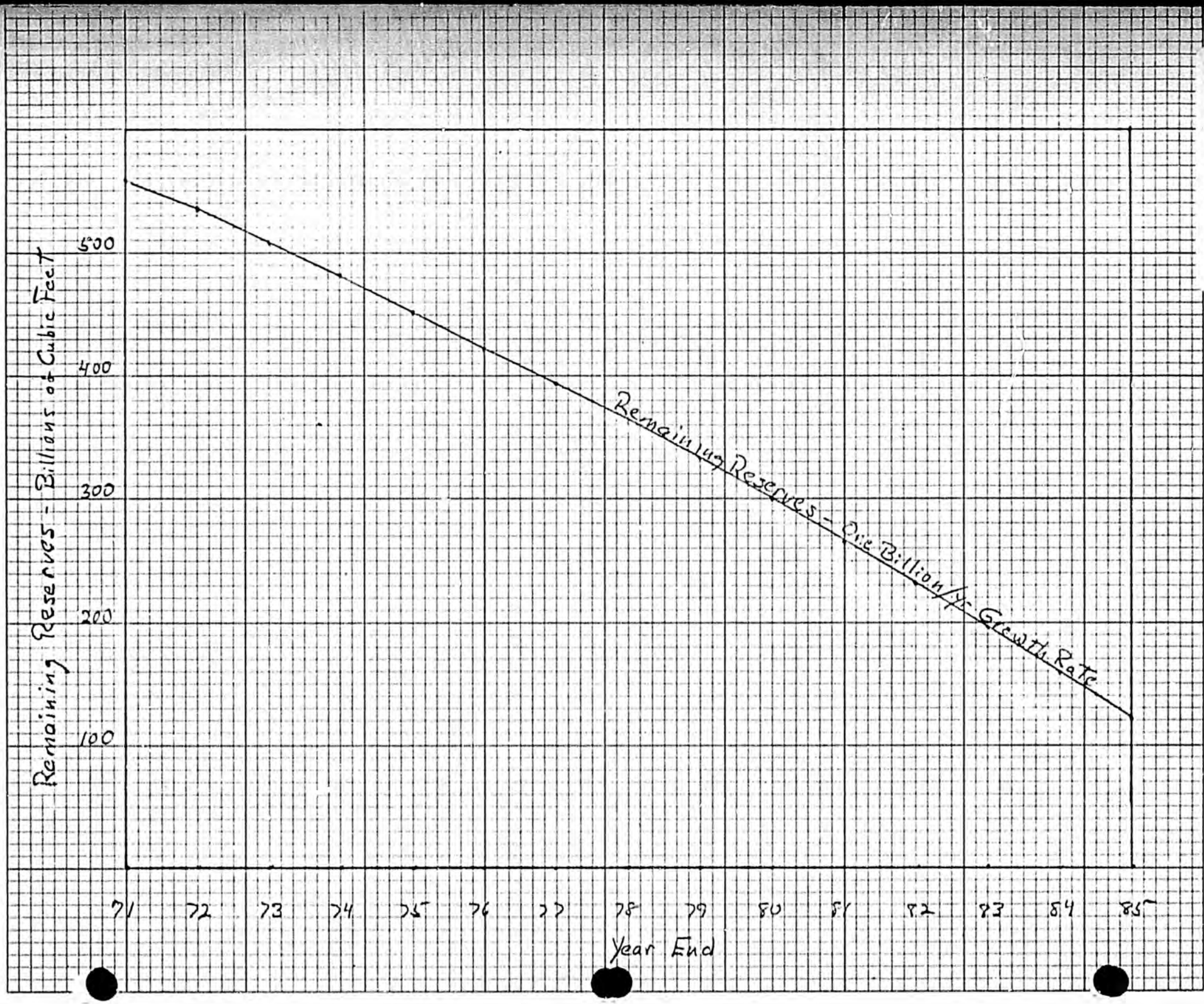
Remaining Reserves - Billions of Cubic Feet

100 200 300 400 500

71 72 73 74 75 76 77 78 79 80 81 82 83 84 85

Year End

Remaining Reserves - Two Billion/yr. Growth Rate

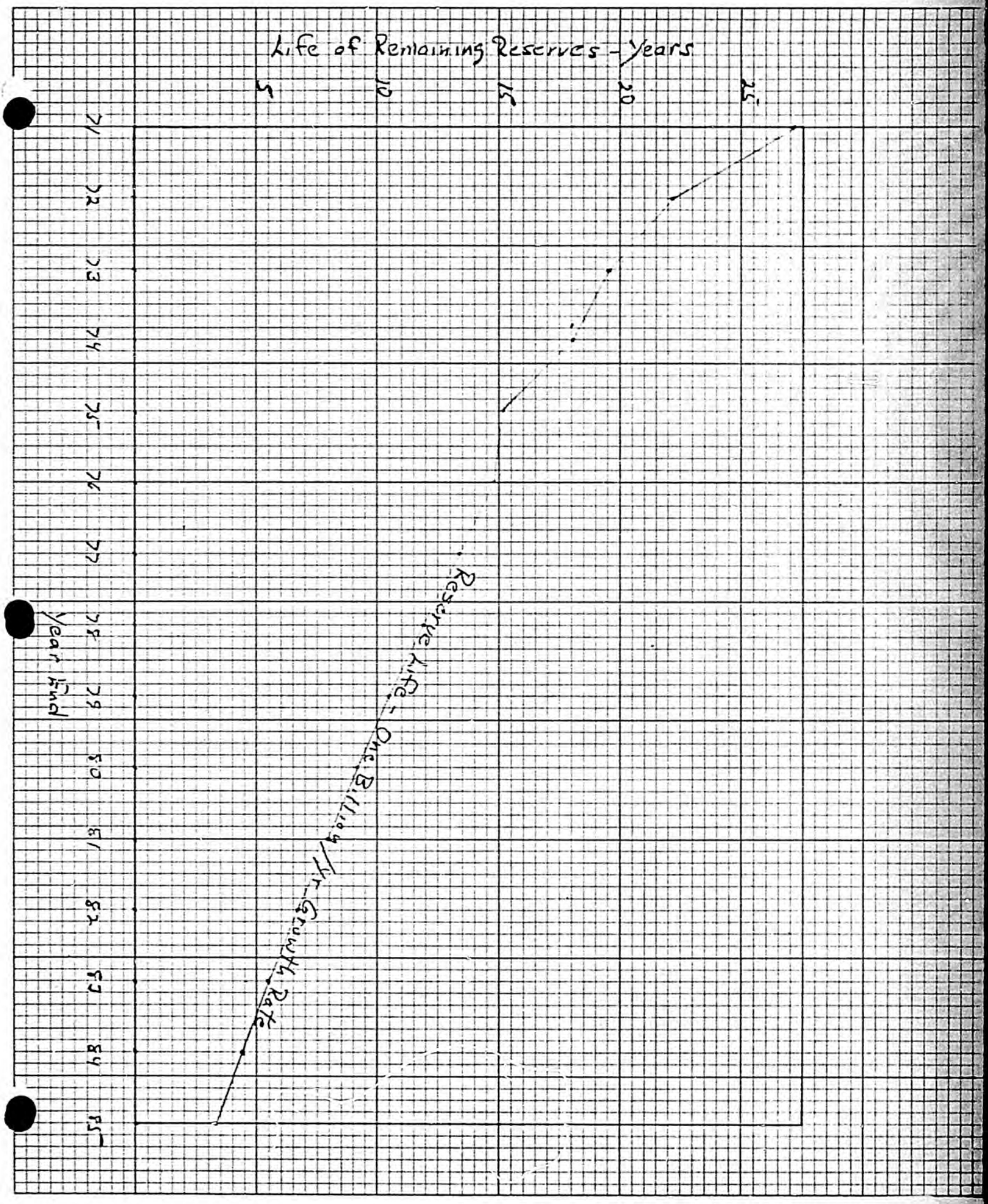

Remaining Reserves - Billions of Cubic Feet
500
400
300
200
100
Remaining Reserves - One Billion/yr. Growth Rate
71
72
73
74
75
76
77
78
79
80
81
82
83
84
85
Year End

AGO 801876

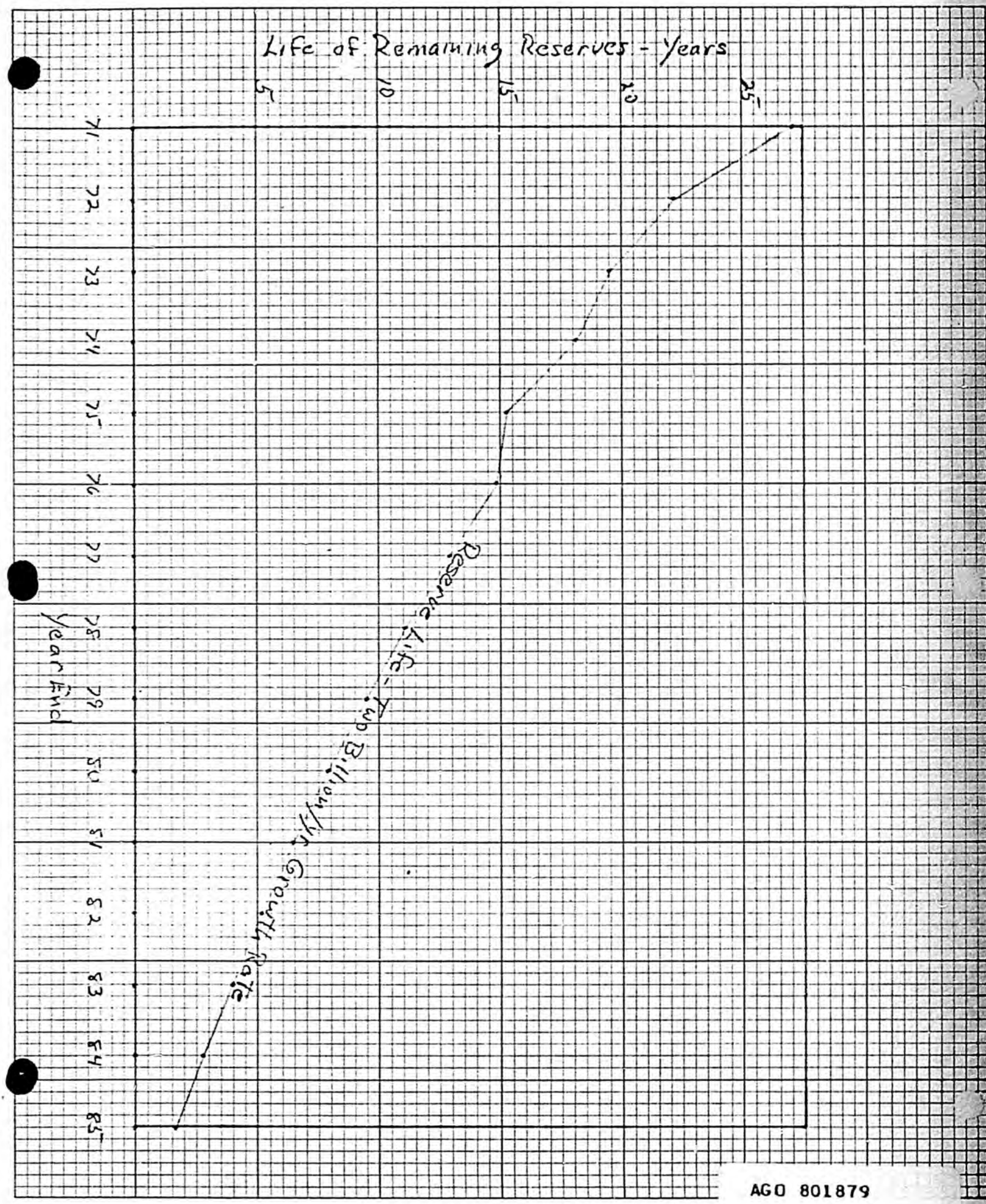
ALASKA GAS AND SERVICE - ALASKA PIPELINE COMPANY

Table of Life of Remaining Reserves

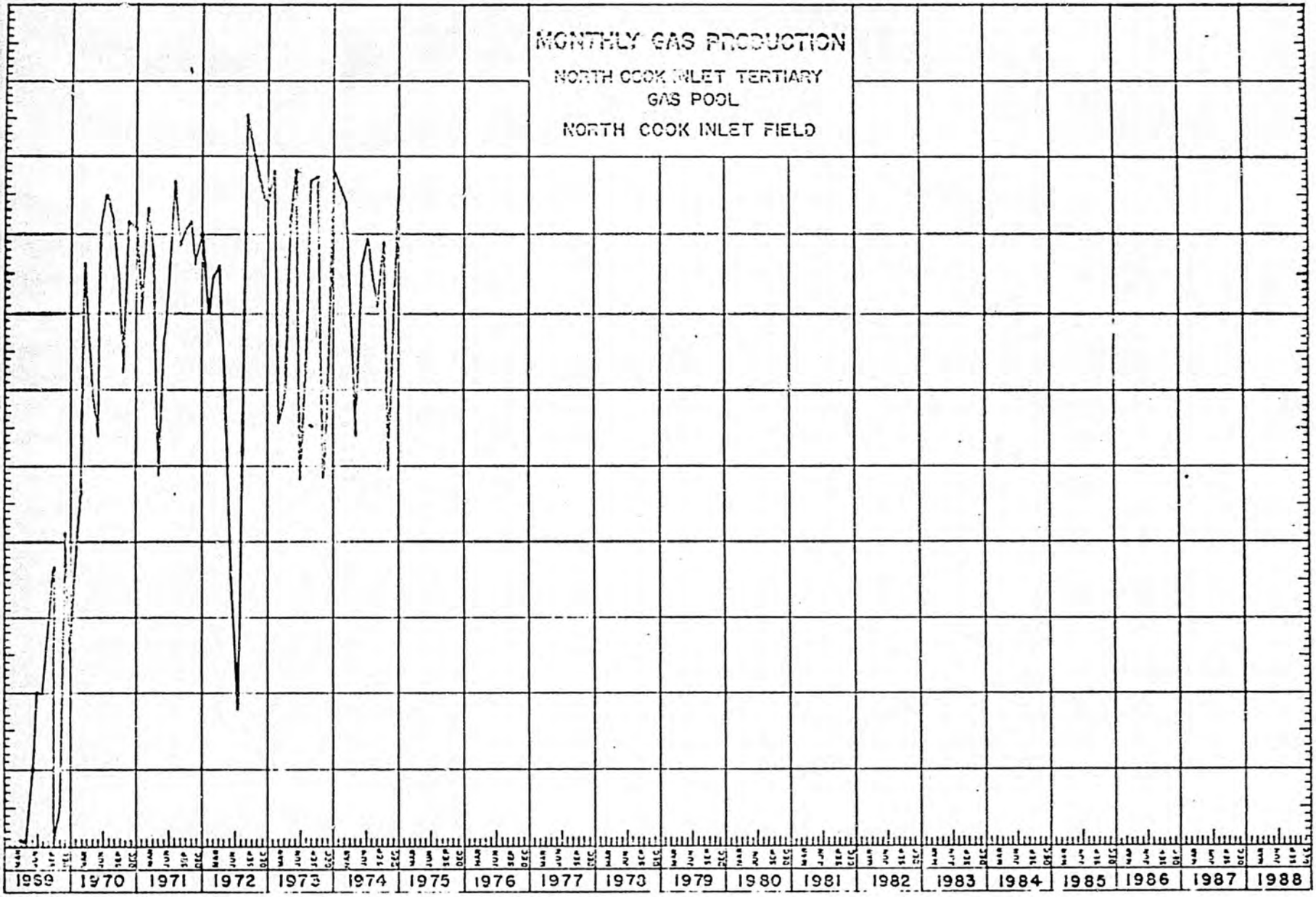
Year End	Life-Years (One Billion CF/yr Growth Rate)	Life-Years (Two Billion CF/yr Growth Rate)
1971	27.1	27.1
1972	22.2	22.2
1973	19.5	19.5
1974	18.1	18.1
1975	15.2	15.2
1976	14.9	14.9
1977	13.4	12.9
1978	11.9	11.1
1979	10.5	9.5
1980	9.2	7.9
1981	7.9	6.5
1982	6.7	5.2
1983	5.5	4.0
1984	4.4	2.8
1985	3.3	1.7


Life of Remaining Reserves - Years
5
10
15
20
25
Year End
71
72
73
74
75
76
77
78
79
80
81
82
83
84
85
Reserve Life - One Billion/Yr Growth Rate

AGO 801878


Life of Remaining Reserves - Years
5
10
15
20
25
Year End
71
72
73
74
75
76
77
78
79
80
81
82
83
84
85
Reserve Life - Two Billion/Yr Growth Rate

AGO 801879


MONTHLY GAS PRODUCTION
NORTH COOK INLET TERTIARY
GAS POOL
NORTH COOK INLET FIELD
BILLION CUBIC FEET PER MONTH
0
1
2
3
4
5
1969
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988

AGO 801880

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

September 30, 1975

Mr. Guy Martin
Commissioner of Natural Resources
State of Alaska
Juneau, Alaska

Dear Mr. Martin:

Confirming our discussion at the Anchorage airport on September 30, and my letter to Mr. Gilbreth of August 20, and memorandum to you of September 24, Alaska Pipeline Company is requesting to purchase the royalty share of North Cook Inlet gas field at or near the Phillips-Marathon LNG plant on the North Kenai Road, at the price used by Phillips to acquire this gas from the State for the manufacture of LNG for export to Japan or elsewhere. We believe the most reasonable method for handling the delivery and sale would be by "exchange," or "displacement," so that construction of new pipeline(s) and compression would be minimized. Since our supply at the Kenai gas field is interconnected to the North Cook Inlet gas supply at the LNG plant, for the time being it should be practical that we would take whatever amount of the North Cook Inlet royalty gas may be available day by day by displacement into our system at the Kenai gas field. Later, when additional investment would be required for transporting this royalty gas to shore, we could negotiate our participation in investment, or install our own facilities if necessary, in order to accomplish the purchase on the most reasonable basis for all concerned.

The essential aspect of our request is that we have an immediate need for additional gas on the North Kenai Road and we have a long term requirement for additional gas reserves to serve Alaskan customers in our present service area. We believe that it is in the public interest that we should be allowed to purchase this State royalty gas for local consumption rather than for this gas to be exported to Japan or elsewhere. We will begin preparing a formal

AGO 801881

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OCT 6 1975
ALASKA ROYALTY
OIL & GAS BOARD

DEPARTMENT OF
NATURAL RESOURCES
OCT 6 1975
RECEIVED
JUNEAU, ALASKA

application to purchase this gas and will appreciate having your guidance as to what supporting data or format may be desired, if any, for presentation to the Royalty Board or to the legislature to satisfy statutes or regulations which apply.

Very truly yours,

Dale Teel

DT/js

cc: O. K. Gilbreth, Director
Division of Oil and Gas

Alaska Public Utilities Commission

B W

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

September 26, 1975

Mr. Guy Martin
Commissioner of Natural Resources
State of Alaska
Juneau, Alaska

Dear Guy:

I have been reading of your appearances in various cities and am not surprised that we have not been able to get together for lunch or otherwise. Now I'm trying to leave the country on October 10 for two weeks. If the royalty board meets October 9 as I've heard, I could attend -- but not on the 10th. Meanwhile, I've put down some of my ideas in a memo and enclose it to you as an indication of what we have in mind on the royalty gas. We are also attempting to obtain the earliest possible restoration of the "flow through" provision of our tariffs at the Alaska Public Utilities Commission so that we will be in a position to contract at the earliest opportunity if our request is approved.

12/2/75 ltr to APUC, last paragraph.

Sincerely,

Dale Teel
President

DT/js

cc: Alaska Public Utilities Commission

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SEP 29 1975
ALASKA ROYALTY
OIL & GAS BOARD

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

DEPARTMENT OF NATURAL RESOURCES

SEP 29 1975

RECEIVED
JUNEAU, ALASKA

MEMORANDUM

TO: Mr. Guy Martin
Commissioner of Natural Resources

FROM: Dale Teel

DATE: September 24, 1975

SUBJECT: Alaska Pipeline Company's Request to Purchase State Royalty Gas from the North Cook Inlet Gas Field ("Phillips")

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SEP 29 1975

ALASKA ROYALTY
OIL & GAS BOARD

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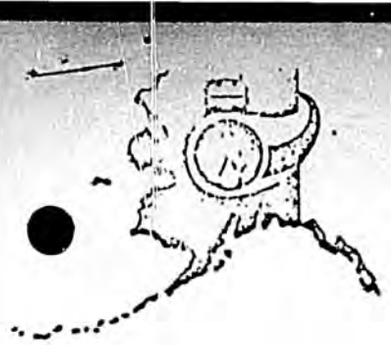
DT/js
enclosure

cc: Alaska Public Utilities Commission



ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

August 20, 1975

COPIES SENT TO:

Paul Robison
Sebe Eastland
Harold Schmidt
O. C. Honig

Mr. O. K. Gilbreth, Director
Division of Oil and Gas
State of Alaska
Department of Natural Resources
3001 Porcupine Street
Anchorage, Alaska 99504

Dear Easy:

We have a gas supply contract with Union-Marathon for 10 BCF on the Kenai North Road which expires May 1, 1977. Due to accelerated sales to Chugach Electric's Bernice Lake power plant this year, it appears the entire reserve quantity could be used up within less than one year from now, and we are soliciting a replacement supply of gas to serve Chugach and our other customers on the Kenai North Road.

We are in a position to commit to take more than our North Road requirements, however, and would like to offer to purchase the State's royalty share of Phillips' production from North Cook Inlet, delivered to a metering point near the Phillips-Marathon LNG plant on the Kenai North Road. The excess above our Kenai North Road sales would be used to displace deliveries by Union-Marathon to us at the Kenai gas field, and thus serve to prolong the adequacy of our reserve commitment at the Kenai gas field. We are not certain as to whether or not the displacement can be made "on paper," or whether we would be required to lay a pipeline to connect into our Anchorage pipeline either at or near the Kenai gas field or at or near our compressor station east of the Kenai River.

Please consider this letter to be an application to purchase royalty gas as described, pursuant to AS 38.06.010. Since limited time is available to do any necessary construction, we hope all procedural requirements can be determined readily. We would anticipate paying the State the same price it would have received from Phillips, which we believe to be 45¢ per MCF plus 5.45¢ transportation fee, as compared to the current 41.5¢ cost of gas (and deliverability) at the Kenai gas field.

? how much

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SEP 29 1975
ALASKA ROYALTY
OIL & GAS BOARD

We are relying on approval by the Alaska Public Utilities Commission for us to "flow through" the increased cost of gas to Chugach's Bernice Lake power plant and to "meld" the (higher) cost royalty gas with the (lower) cost Kenai field gas, on a day-to-day basis, since the amount of royalty gas we would receive would depend on the rate of production of the Phillips-Marathon LNG plant and be outside our control. When this plant is down for any reason, we would be utilizing Kenai field gas as replacement.

Please advise regarding any questions or further procedure we should follow in presenting a formal offer to the State.

Very truly yours,

Dale Teel
President

DT:lkd

cc: Alaska Public Utilities Commission

HEA

file: Homer Elec

Homer Electric Association, Inc.

P. O. BOX 429 • HOMER, ALASKA 99603 • PHONE (907) 235-8551

February 16, 1977

Mr. Don Wold
State of Alaska
Royalty Oil & Gas Development Board
Pouch M
Juneau, Alaska 99811

Dear Mr. Wold:

During the year of 1976, because of an unprecedented growth in the population of its service area, the Homer Electric Association became aware of a pending crisis in its future supply of wholesale electrical power.

This association serves all of the communities on the Kenai Peninsula except Cooper Landing and Seward. The current number of meters served is 7200 and anticipated growth in numbers is expected to be (based upon actual growth in 1976) approximately 20% per year for the next few years.

Homer Electric has enjoyed a wholesale electrical supply contract wherein they purchased their needs at cost from the Chugach Electric Association since 1969. Present demands upon the Chugach system plus a reluctance upon the part of Chugach to provide for the future power requirements of Homer has dictated a departure from this present arrangement. Late in 1976, Chugach agreed to let Homer acquire its gas fired generating facility located nine miles north of Kenai (known as the Bernice Lake Plant) and thence Homer would provide for its present and future needs of electrical supply as required by the growth of its service area.

Upon investigation it was revealed that a gas fuel supply would not be certain at the Bernice Lake facility after April 30, 1977. Homer has made application to all of the major gas suppliers and producers in the area and has not received an assurance of a gas supply at any price. The Homer Electric Association is now applying to the State of Alaska, through its Department of Natural Resources, to make available the State's royalty share of natural gas from the Kenai field for use at the Bernice Lake Plant. This gas is presently being used by various producers in the field at a reported price of from 24.5 to 34.8 cents per thousand cubic feet.

AGO 801889

Homer is willing to pay the State 60¢ per thousand cubic feet delivered to the Bernice Lake Plant for quantities set out in our letter of February 11, 1977.

The State has a supply of gas that it can make available for use to the benefit of the citizens of the Kenai Peninsula as set forth in the information attached marked Exhibit A.

It will be noted by reviewing the attached exhibit that only 14.6 percent of the gas used in 1974 was for the direct benefit of the citizens of Southcentral Alaska. Projected use in 1980 indicates only 11.7 percent will be used for the purpose stated above.

Sincerely yours,

W. C. Rhodes
General Manager

(EXHIBIT A)

Current production of "dry gas" on the Kenai Peninsula represents only 2% of known reserves and only slightly more than 1/2 of 1% of known plus patented reserves according to the Stanford Research Institute study released in December of 1975. Natural gas is being consumed or utilized for the following purposes:

Catagory	Use 1974(Billion CF)	Use 1980(Billion CF)
Electric Power Gen.	17.11	33.04
Ammonia Manufacturing	22.10	44.20
Household-Commercial	9.87	14.83
Refinery Fuel	.87	2.28
Lease & Plant fuel	14.37	16.73
Shrinkage & Flaring	9.58	7.23
Military Use	5.86	5.86
Export LNG	61.87	88.38
Repressure (Gross Injection)	86.81	86.81
	228.44	459.92

Source: Reference number 7 of the above mentioned study.

Table 18 of this study estimates a recoverable existing reserve as of January 1, 1975 of 7,117 billions of cubic feet or a 31.42 year supply based upon 1974 actual use or a 15.6 year supply based upon estimated 1980 usage.

Insufficient demand is the reason that nine of the existing gas fields are still shut-in and the remainder are producing well below capacity. Production of gas could be more than doubled without addition to known reserves.

Homer Electric Association, Inc.

P. O. BOX 429 • HOMER, ALASKA 99603 • PHONE (907) 235-8551

File: [redacted] Proposals

February 11, 1977

RECEIVED
FEB 14 1977
ALASKA ROYALTY
OIL & GAS BOARD

Mr. Don Wold
State of Alaska
Royalty Oil & Gas Development Advisory Board
Pouch M
Juneau, Alaska 99811

Dear Mr. Wold:

Confirming our various telephone conversations, the purpose of this letter is to formally request your cooperation in obtaining for our association the State Royalty Gas available from the Kenai Gas Field. We would like to use this gas as fuel for the Bernice Lake Power Plant beginning May 1, 1977. The plant is located North of Kenai, adjacent to the Standard Oil Company.

We are presently conducting negotiations with Chugach Electric Association to acquire this plant, now owned by them, and to re-acquire our large transmission lines presently leased to them, which originate in the Kenai Lake area and provide electric service to the Peninsula. The reason for the acquisition of this property is the constant deterioriation of electrical service to the industrial plants on the North Kenai Peninsula, and the inability or reluctance of Chugach to guarantee our association adequate wholesale power for our future needs.

If we are successful in acquiring a gas supply at an acceptable price for the Bernice Lake plant we will conclude our negotiations with Chugach and proceed to build additional generating facilities at the Bernice Lake site. During the interim period, until the additional generating facilities are installed, we will require an average of approximately 5,700 mcf per day. With winter peaks, that may require 9,000 mcf. After January 1, 1979, which is our target date for the completion of the new generation facilities, our daily average requirement would be slightly in excess of 8,000 mcf with peaks that could approach 17,000 mcf.

Your urgent cooperation is requested in assisting us to obtain a fuel supply as a decision must be reached in our negotiations within the next few days.

The alternative to our acquisition of the generating facilities will be a future dependence upon wholesale electrical energy supplied by Chugach. They have indicated that they are unwilling to continue to supply us wholesale energy for use by industry under the present rate structure, and have said that they will insist upon a substantial increase if they are forced to continue under the present contract. The existing wholesale electric supply

contract is effective until the Year 2008, and, of course, would be cancelled if we acquire their property on the Kenai Peninsula.

We hope the above background information is sufficiently complete to assist you and your staff in drafting a proposal. However, if you should have any questions please contact me and we will provide any additional material that you may require.

Sincerely yours,

HOMER ELECTRIC ASSOCIATION, INC.

W. C. Rhodes
General Manager

WCR:em

STATE
of ALASKA

MEMORANDUM

RECEIVED
JAN 11 1977
Department of
Natural Resources

TO: Guy Martin, Commissioner
Department of Natural Resources

DATE: January 7, 1977

FROM: Don Wold

SUBJECT: Homer Electric Association Inc.

Alaska Royalty Board
Department of Natural Resources

Bill Rhodes, General Manager, called 1-6-77 in an attempt to set up a meeting between the Alaska Public Utilities Commission, Gordon Zerbetz, Alaska Pipeline Company, Dale Teel, Harold Schmidt, Homer Electric Association, Bill Rhodes, Phillips Petroleum Co., John Horn, Department of Natural Resources, Guy Martin, Don Wold.

Mr. Rhodes is, of course, still attempting to purchase gas to run the Bernice Lake power plant which he is attempting to purchase from Chugach Electric. He desires to purchase the royalty gas presently under contract to Alaska Pipeline Company. Mr. Rhodes is aware that presently Alaska Pipeline Company is unable to receive the gas because they are unable to obtain a waiver of Jurisdiction by the PUC for Phillips over the pipeline to be used to deliver the gas. Mr. Rhodes believes that since Alaska Pipeline Company cannot receive the gas then he should be allowed to purchase it and try to solve the delivery problem. I understand that Mr. Rhodes will proceed to purchase the Bernice Lake power plant and will use it for standby only and run diesel of fuel oil as needed if he cannot purchase gas at a reasonable price. He also says that he can purchase gas from the Kenai Utility at 50¢/MM BTU but it cannot be exported from that area. He may have to purchase that gas and have his power generated there and run a power line to his service area. He also states that he is working on other alternative supplies of gas. Finally, he is asking for a meeting between all parties to get the issues resolved.

Called Harold Schmidt, Alaska Pipeline Company, who recommended that all sides of the story be known before such a meeting. He would also like to meet to review the gas contract and explain part of the problem. He will visit Juneau on Monday and Tuesday, 1-10-77 and 1-11-77 for such discussions.

Called Gordon Zerbetz, PUC, on 1-7-77 who states that PUC can do nothing unless Phillips makes application for the waiver. Phillips apparently will make no attempt to do so. Mr. Zerbetz also states that the Alaska Pipeline Commission has been meeting with the PUC to determine if APC has jurisdiction over such pipelines. He also suggested that we meet to discuss the issues in detail.

Homer Electric Association, Inc.
P. O. BOX 429 • HOMER, ALASKA 99603 • PHONE (907) 235-8551

December 9, 1976

RECEIVED
DEC 13 1976
ALASKA ROYALTY
OIL & GAS BOARD

RECEIVED
DEC 13 1976
Department of
Natural Resources

Mr. Gordon Zerbetz, Chairman
Alaska Public Utilities Commission
1100 MacKay Building
338 Denali Street
Anchorage, Alaska 99501

Dear Sir:

Our Association has entered into active negotiations to acquire generating facilities presently owned by the Chugach Electric cooperative, located approximately 9 miles north of Kenai, and known as the Bernice Lake Power Plant.

The acquisition of these facilities, along with the cancellation of a long-term "all requirements" wholesale energy contract with Chugach, will enable this association to plan and provide for generating and transmission facilities as future needs dictate. This plan will also allow us to promote the early construction of the Bradley Lake Hydro generating plant, which will provide electric energy in the future without dependence upon fossil fuels.

We attempted to negotiate with the Alaska Gas and Service Company to obtain a dependable source of fuel for the Bernice Lake generating plant, however, that company did not give us any assurance of a permanent supply of gas as evidenced by their letter of November 16 to us with a copy to the Commission.

In the letter from the Alaska Gas and Service Company, they mention a contract with Phillips, which is dependent upon a waiver of jurisdiction from the Commission, an amendment to the gas company's contract with the State of Alaska for Royalty Gas, financing additional pipeline, construction of that line, and then Commission approval of a rate design for a special contract with us. It is obvious that these items will require negotiations covering a span of several months.

In order for our association to go forward with the plan to acquire the Bernice Lake facilities, we have certain deadlines to meet that have a relationship to the pending change in personnel brought about by a change in the national administration. If we cannot go forward with this plan prior to the change-over in the hierarchy of the Rural Electrification

AGO 801895

Administration in Washington, it will be necessary to re-educate a group of people far away from Alaska unfamiliar with the needs of our association. The encumbents of these positions are sympathetic with our negotiations with Chugach and await only a formal document for final approval of the above mentioned arrangement.

The Alaska Gas and Service Company's proposed contract with Phillips is dependent upon a waiver of the Commission. We do not feel that the Commission can grant such a waiver because the gas company would then take this gas for use in intra-state commerce, and, hence, in our opinion, will be properly subject to regulation by the Commission.

We are presently negotiating with Phillips and the Alaska Gas Royalty Board for direct acquisition of the Royalty Gas from Phillips, to be used at the Bernice Lake site as fuel for the existing generators and for additional generating facilities that are planned to be installed at the earliest possible date.

The purpose of this letter, in addition to keeping you informed as to our overall plans, is to request from the Commission a statement that can be used in our negotiations with Phillips to the effect that the Commission will not take jurisdiction over this State Royalty Gas because our use of this gas will be for the purpose of manufacturing electrical energy for resale under tariffs directly under the control of the Commission. In our opinion the gas fuel would not be subject to the Commission's regulation any more than fuel oil or the purchase of components necessary to erect the generating station.

We have a meeting scheduled with Phillips Petroleum Company in Bartlesville on December 17, and an expression of the Commission's feelings in writing prior to that date would aid us greatly in these negotiations.

We sincerely appreciate your cooperation in this matter.

Sincerely yours,

HOMER ELECTRIC ASSOCIATION, INC.

W. C. Rhodes
General Manager

WCR:em
cc: John Horn, Phillips Petroleum
cc: Alaska State Royalty Board

AGO 801896

cc: [illegible] Ok Galbraith F Bo[illegible] Royalty Board copied 12/3/76 [illegible]

Homer Electric Association, Inc.

P. O. BOX 429 • HOMER, ALASKA 99603 • PHONE (907) 235-8551

November 30, 1976

Mr. Don Wald
State of Alaska
Royalty Oil & Gas Development Advisory Board
Pouch M
Juneau, Alaska 99811

Dear Mr. Wald:

Thank you for calling me on the telephone today and discussing price and availability of State Royalty Gas from the North Cook Inlet Field.

To help clarify the matters discussed in our telephone conversation, we are enclosing a copy of our letter of November 12 to the Alaska Gas and Service Company and a copy of their response dated November 16.

You will note that we requested that the gas company quote us prices for a continuous supply of natural gas, and in the absence of such assurance, we further requested their permission to obtain gas from any other available source in that area. The gas company maintains that this area is in their certificated service area, however, I have been unable to verify this with the Alaska Public Utilities Commission.

In reading the letter from the gas company, you will note that they did not promise a continuous supply of natural gas, nor did they give us permission to obtain gas from other sources.

In other correspondence from the gas company they indicated that they are not certain that they would be able to use all of the Royalty Gas available in that area, and would re-negotiate their contract with the Royalty Board to seek permission to return part of the Royalty gas to Phillips. In fairness to the electric consumers on the Kenai Peninsula whose rates for service will eventually be based partially on the cost of fuel for generating purposes, we can see no logic in the State turning this gas over to the Alaska Gas and Service Company, whose only customer for the Royalty gas, under the present conditions, is the power plant that we are in the process of acquiring in the North Kenai Area.

We, therefore, request the Royalty Board to consider making this gas available to the Homer Electric Association, who admittedly cannot use all of the gas at the present time, but would be willing to negotiate a sale for that quantity that is surplus to our needs, and, hence, assure the State of a market for all of the Royalty gas presently being delivered to Phillips.

We appreciate your cooperation in this matter.

Sincerely yours,

HOMER ELECTRIC ASSOCIATION, INC.

W. C. Rhodes
General Manager

WCR:em

Enclosures

From: Wold

11-30-76

The Alaska Royalty Oil and Gas Development Advisory Board

Homer Electric Assoc

Bill Rhodes - 235-8677

Wants to know price of Cook Inlet royalty gas to Alaska Pipeline - Has ltr offering to sell at 86.81¢/ft³ on 2 hr notice interrupt - from Teel to Alaska Pipeline -

Trying to purchase Chugach Bernice Lake Plant - $4 mm - contract expires Apr '77

Needs ~~[illegible]~~ 8 mm ft³/day

Alaska Pipeline cannot handle all gas and apparently will resell it to Phillips.

AGO 801899

Alaska Gas and Service Company

GENERAL OFFICES LOCATED AT 3000 SPENARD ROAD
P. O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-5551
TELEX 25-187

November 16, 1976



Mr. W. C. Rhodes, General Manager
Homer Electric Association, Inc.
P. O. Box 255
Homer, Alaska 99603

Dear Mr. Rhodes:

Confirming our conversation of November 12, 1976 and in response to your letter of that date, we can offer only interruptible (not continuous) service to you for the Bernice Lake power plant. Interruptions or curtailments would be upon two (2) hours' notice. The service would be by a special contract and thus subject to the approval of the Alaska Public Utilities Commission (APUC).

We would propose service to you at a minimum bill of $5,000 per month and with a price, at this writing, of $0.8681 per MCF for gas of approximately 1000 btu per cubic foot (but not less than 950 btu/cf), and at pressure and quality suitable for use as fuel for the Bernice Lake power plant.

This is the price in effect as our rate "SK-5", which is a filed tariff. We would expect to have the contract take effect January 1 or the date of your acquisition of the Bernice Lake power plant if earlier, and continue indefinitely.

Per our discussion, our gas supply on the North Kenai Road is indefinite; we are attempting to begin purchasing State royalty gas on or before May 1, 1977 on the expiration of our contract with Union-Marathon. Alternately, we would hope to extend our contract with Union-Marathon until purchase of royalty gas could begin. We are planning a pipeline along the route and in the right of way of your power transmission line (from Quartz Creek to Bernice) to cover any outages of royalty gas and to gather royalty gas into our pipeline to Anchorage. It may not be practicable to complete this pipeline by May 1, and it might be necessary for some oil to be used although we will make every effort to have the line built or else to get the extension of our supply by Union-Marathon. As you know this plant burned oil for 10 years or more and it is essential that oil capability be maintained.

Alaska Gas and Service Company

GENERAL OFFICES LOCATED AT 3808 SPENARD ROAD
P.O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277 5551
TELEX 25-187

No contract yet; what basis

We are of course proud of our record of reliable service with a minimum of curtailments, and we would hope to continue it with you as our customer. However, many elements are now operating which may be or are beyond our control. First, we urgently need APUC waiver of jurisdiction over Phillips. Second, we need to amend our contract with the State to conform with the contract with Phillips (I gave you a copy). Third, we must get financing for the pipeline, and Board approval; fourth, we must build the line; and last, we must get APUC approval of our rate design generally and the special contract with you in particular. Our rate design will be at hearing December 6, and we will draft the special contract for service to you upon the conclusion of that hearing. We can pledge to you our best efforts in all these undertakings, but we cannot commit their timely completion. We appreciate your helpfulness thus far and may need to call on you again.

- that completed

Very truly yours,

Dale Teel

dh

cc: APUC with copy of HEA Letter 11/12/76

Homer Electric Association, Inc.
P. O. BOX 255 • HOMER, ALASKA 99603 • PHONE (907) 235-8551

Royalty Gas file

November 12, 1976

Mr. Dale Teel, President
Alaska Gas Service Company
3000 Spenard Road
P. O. Box 6288
Anchorage, Alaska 99502

Dear Mr. Teel:

Confirming our conversation of today, we are in the process of negotiating the acquisition of the Bernice Lake Power Plant from Chugach Electric Association.

In order to go forward with these negotiations, it will be necessary to have a commitment from your organization that a continuous supply of natural gas for fuel will be available at the Bernice Lake site, and the anticipated price and conditions of a proposed contract.

In absence of this assurance that we will be able to obtain the gas supply, we request your permission to obtain gas from any other available source in your service area.

As the anticipated closing date of these negotiations is the first week of January, 1977, we urge your immediate attention to this matter.

Thank you for your cooperation.

Sincerely yours,

HOMER ELECTRIC ASSOCIATION, INC.

W. C. Rhodes

W. C. Rhodes
General Manager

by fma

WCR: em

AGO 801902

April 6, 1976

Mr. W.C. Rhodes
Homer Electric Association, Inc.
P. O. Box 255
Homer, Alaska 99603

Dear Mr. Rhodes:

Your letter to Commissioner Martin withdrawing your application for the North Cook Inlet Field royalty gas has been forwarded to me.

We will place your name on our mailing list to keep you advised on the Board's activities.

Attached is a copy of the notice and informative summary to define "industrial use". This regulation does not attempt to set a priority status. Presumably priorities would be set from time to time as warranted by conditions at that time and might well be a matter of State policy which is beyond the Board's responsibility.

We appreciate your notification of withdrawal and are pleased that you have made satisfactory arrangements for a gas supply.

Yours truly,

William C. Fackler

William C. Fackler
Executive Director

Attachment

WCF:dk

Homer Electric Association, Inc.
P. O. BOX 255 • HOMER, ALASKA 99603 • PHONE (907) 235-8551

March 30, 1976

RECEIVED
APR - 2 1976
Department of
Natural Resources

Mr. Guy Martin, Commissioner
Royalty Oil and Gas Development Advisory Board
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Dear Sir:

In our letter to Mr. Fackler dated January 22, 1976, and at a hearing before your Advisory Board, we applied for the State Royalty Gas that you plan to make available from presently producing fields in the North Kenai area.

The purpose of this letter is to inform you that we have been able to obtain commitments to purchase fuel for the proposed new electric generating facility at North Kenai from what we believe to be a reliable source; and, further, Mr. Dale Teel of the Alaska Pipeline Company has agreed to supply our Association with natural gas for fuel for the existing electric generating plants in the North Kenai area if we are successful in acquiring these from Chugach Electric Association.

In view of the foregoing, we feel that it is in the best interest of all concerned that we withdraw our application as outlined in our letter of January 22.

As the Kenai Peninsula continues to attract industry, we do not wish to imply that we will not, at some future time, be interested in dealing with the State for royalty gas that may become available in other, yet to be developed, fields on the Kenai Peninsula area. If, at any time, additional royalty gas does become available we would appreciate it very much if your office would advise us so that we can ascertain whether or not it would be needed in our ever-expanding operation.

We note with interest the development of the Advisory Board's intention to adopt a regulation in Title 11 of the Alaska Administrative Code to interpret and make specific Alaska Statute 38.06, including the determination of surplus.

RECEIVED
APR 05 1976
ALASKA ROYALTY
OIL & GAS BOARD

We sincerely hope that the proposed regulation 11AAC26.900(a) (5) will define the term "industrial use" as referred to in existing regulations, and that the State's royalty gas will be made available first to industrial use and then to all other uses, according to priorities established by your office.

We sincerely appreciate the courtesies extended to our Association by the Advisory Board and your office, and we are looking forward to further negotiations should the need arise.

Sincerely yours,

HOMER ELECTRIC ASSOCIATION, INC.

W. C. Rhodes
General Manager

WCR:em

cc: Rep. Leo Rhode
cc: Mr. Dale Teel

Homer Electric Association, Inc.

P. O. BOX 255 • HOMER, ALASKA 99603 • PHONE (907) 235-8551

RECEIVED
FEB 17 1975
ALASKA ROYALTY
OIL & GAS BOARD

February 11, 1976

Mr. William C. Fackler, Executive Director
Department of Natural Resources
State of Alaska
Alaska Royalty Oil & Gas Development Advisory Board
Pouch M
Juneau, Alaska 99811

Dear Mr. Fackler:

Thank you for your letter of February 9, 1976, addressed to Mr. W. C. Rhodes, with reference to H.E.A.'s interest in purchasing North Cook Inlet royalty gas, and advising of the February 23 meeting in Juneau.

Since Mr. Rhodes is presently out of the state, but will return prior to the meeting, this is to advise that he definitely wishes to be scheduled for the February 23 meeting.

Thank you for your cooperation in this matter.

Sincerely yours,

HOMER ELECTRIC ASSOCIATION, INC.

Elaine McCullough
Secretary to General Manager

em

RECEIVED
FEB 17 1976
Department of
Natural Resources

Alaska Royalty Oil & Gas Development Advisory Board

February 9, 1976

Mr. W.C. Rhodes
Homer Electric Association
P. O. Box 255
Homer, Alaska 99603

Dear Mr. Rhodes:

The Royalty Board has received your letter advising that the Homer Electric Association is negotiating with Chugach Electric Association for the Bernice Lake generating facility, and consequently H.E.A. is interested in purchasing North Cook Inlet royalty gas.

The North Cook Inlet royalty gas sale will be an item on the agenda for the next Board meeting which is February 23, 1976, in Juneau in the Fifth Floor Conference Room of the State Office Building. The meeting will begin at 10:00 a.m.

It would be advantageous for you to present your position in person at the meeting. I suggest that you include such items as amount of gas, point of delivery, price, term of contract and so forth.

Please advise me if you wish to be scheduled for that meeting.

Yours truly,

William C. Puckler
Executive Director

WCP:dk

file H.E.A.
dk

AGO 801907

Homer Electric Association, Inc.

P. O. BOX 255 • HOMER, ALASKA 99603 • PHONE (907) 235-8551

January 22, 1976

RECEIVED
JAN 26 1976
Department of
Natural Resources

Mr. William C. Fackler, Exec. Secy.
Alaska Royalty Oil & Gas Advisory Board
Pouch M
Juneau, Alaska 99811

Dear Mr. Fackler:

The purpose of this letter is to inform you and your Commission that our Association is entering into negotiations with Chugach Electric Association to acquire their gas fired electric generation facilities at Nikiski.

These facilities are presently consuming approximately 9 million cu. ft. per day of natural gas, which is purchased from the Alaska Pipeline Company. In addition to the present gas consumption, we intend to construct prior to the end of calendar year 1978 an additional generating facility at that location requiring an additional 5 to 6 million cu. ft. per day.

We are familiar with the on-going negotiations between your office and the Alaska Pipeline Company concerning State Royalty gas for resale to Chugach and the Anchorage area.

Please consider this letter as an inquiry to determine whether or not we will be able to purchase Royalty Gas in the amounts described above pursuant to Alaska Statutes AS 38.06.010. We would anticipate purchasing all of the royalty gas available at the Phillips Petroleum LNG Plant with the assumption that the amount in excess of our needs available on a day to day basis could be resold to Phillips for their processing plant.

We assume that we would be required to pay the current market price for the gas which we believe to be 45¢ per MCF plus a negotiated transportation fee. Our negotiations to acquire the electric generating facilities in the area and build additional generation facilities is dependent upon our ability to acquire the State Royalty Gas or a like quantity of other gas in that area.

RECEIVED
JAN 62 1975
ALASKA ROYALTY
OIL & GAS BOARD

AGO 801908

Our association is a non-profit cooperative. The membership includes all of the residents and business organizations of the Western Kenai Peninsula. We will greatly appreciate any cooperation that your office can lend us in bringing these negotiations to a mutually beneficial conclusion.

Sincerely yours,

HOMER ELECTRIC ASSOCIATION, INC.

W. C. Rhodes
General Manager

WCR:em

cc: O. K. Gilbreth
W. I. Palmer
Sen. Clem Tillion
Rep. Hugh Malone
Rep. Leo Rhode
Guy Martin

January 20, 1976

The Honorable Leo Rhode
House of Representatives
Pouch V
Juneau, Alaska 99801

Dear Mr. Rhode:

The recent correspondence from Mr. W.C. Rhodes, Homer Electric Association, is the first indication I have had that the HEA is interested in State royalty gas.

Mr. Rhodes should write me as Chairman, Alaska Royalty Oil and Gas Development Advisory Board, Pouch M, Juneau, Alaska 99811 and advise the Board of his desire to purchase royalty gas. His letter should include the amount of gas he needs, possible delivery point or points, suggested term of contract and any other provisions that might apply.

This matter would be placed on the agenda for the next meeting which is February 23, 1976 at Juneau, Fifth Floor Conference Room, State Office Building. Meeting begins at 10:00 a.m. It probably would be advantageous for Mr. Rhodes to make a statement to the Board of his plans and needs and respond to any questions that the Board might have.

The Board will give Mr. Rhodes' request every consideration.

Yours truly,

Guy R. Martin
Commissioner

GRM:dk
cc: WCF

Alaska State Legislature

REP. LEO RHODE

BOX 406
HOMER, ALASKA 99603

LEGISLATIVE ADDRESS
POUCH V
JUNEAU, ALASKA 99801

COMMITTEES:
NATURAL RESOURCES
COMMERCE

House of Representatives

January 14, 1976

Guy Martin, Commissioner
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Dear Guy:

Rather than go into any lengthy detail I am enclosing a copy of a letter from W. C. Rhodes, General Manager of the Homer Electric Association Corporation, relative to the sale of state royalty gas from the Kenai Peninsula.

Mr. Rhodes ably explains the feasibility and need of local consumption for the use of the state's royalty gas at the point of production.

If a hearing is to be scheduled on this subject I am certain Mr. Rhodes would like to testify. Also since I am a director of the Homer Electric Association my interest would be two-fold; however, not in any way would my directorship interest jeopardize the maximum source of state revenues. Your comments would be appreciated.

Very truly yours,

Leo Rhode
State Representative
District 13

LR:jp

cc: W. C. Rhodes

enclosure

AGO 801911

RECEIVED
JAN 16 1976
Department of
Natural Resources

Homer Electric Association, Inc.

P. O. BOX 255 • HOMER, ALASKA 99603 • PHONE (907) 235-8551

December 30, 1975

The Honorable Leo Rhode
House of Representatives
Pouch V, State Capitol
Juneau, Alaska 99811

Dear Sir:

An article in the December 22nd issue of the Oil and Gas Journal states that Alaska is moving to claim for domestic use about 15 million cubic feet per day of state royalty gas, presently exported to Japan, from Phillips-Marathon LNG on the Kenai Peninsula.

The article goes on to state that the gas, representing state royalty of Cook Inlet production, would be used to supply customers in Anchorage under a proposal by an Alaska Royalty Oil and Gas Development Advisory Board.

Another interesting facet of the article indicates that, if this measure is approved by the Legislature, Anchorage Natural Gas Company could be taking gas by late next year. The current through-put of the Phillips-Marathon plant is about 170 million cubic feet per day. It is interesting to note that the 15 million cubic feet per day of royalty gas is almost exactly the amount of natural gas fuel required for electric generation on the Kenai Peninsula during the next four or five years.

We sincerely hope that you will use your good office to make certain that the non-profit electrical cooperatives operating on the Kenai Peninsula will have an opportunity to purchase this gas if it becomes available directly from the State of Alaska. We can see no logical reason why this gas should be turned over to the profit oriented Anchorage Natural Gas Company for resale to the general public on the Kenai Peninsula or in the Anchorage area.

We wish you continued success in the forthcoming session in Juneau, and we will very much appreciate your cooperation when this matter is finally legislated.

Sincerely yours,

HOMER ELECTRIC ASSOCIATION, INC.

W. C. Rhodes
General Manager

WCR:em

AGO 801912

MISC. NOTES

- In their "new" contract of February 22, 1977 the price mentioned is 64.65¢/Mcf which is 4.29¢/Mcf higher than previously agreed upon. (76-1 contract dated 6/4/76).

64.65
60.36
4.29

Why? Is that the transportation cost? No, since the contract provides that APC shall pay 10¢ (without added compression) and 20¢ (with added compression of 3500 hp) in consideration of Phillips' costs* for gathering gas to the point of delivery, which is near Phillips' pipeline tap which delivers gas to the Tesoro refinery, located in the general vicinity of the Kenai LNG plant on the North Kenai Road. Added charges are to be passed on to APC by Phillips as they require/install further compression units. These charges would be proportionate to the gas APC receives from total production.

*(Since these "costs" would be "charged" the State, it would seem that the State does have the right to determine how these charges are arrived at. (and not APC)

AGO 801914

* Cont'd

Even if APC took delivery at the wellhead, as originally proposed, the "costs" assessed APC for delivering the royalty gas to shore would still be the State's business, since APC would undoubtedly ask the APUC to allow them to pass on the cost to the consumers).

- The proposed notice by the State of Alaska to take its royalty gas from the North Cook Inlet Gas Field in kind as prepared by APC and attached to their February 2, 1977 letter states "(You (Phillips) may deduct, from the amount of royalty payment otherwise due the State, the charge(s) described on page(s) 7-9 of the State's contract with APC as consideration for dehydration and gathering including compression of the royalty gas which you (Phillips) will provide to the State. These charges were negotiated by you (Phillips) and are acceptable to the State and to

AGO 801915

APC, as described in the contract..."
The State was not a party to "negotiations" mentioned!? If it was then the royalty board can give us satisfactory breakdowns of the 10¢ (20¢) / Mcf (or 5.45¢) figure when it previously cost 5.5¢ / Mcf to do the same thing.

(See Phillips' letter to APC re differing costs for same thing 1/76)

If it was not, it should be because since ~~it~~ (under the terms of the "new" contract) the State takes delivery onshore, and the State technically gets assessed the costs for dehydration and gathering, including compression of the royalty gas from the North Cook Inlet gas field.

— The proposed notice ~~(and supposedly)~~ the new proposed contract ~~(check this)~~ also reiterate that Phillips shall not be subject to the jurisdiction of the APUC or (Alaska Pipeline Commission,) and that the notice or contract would not affect the price payable to the State for royalty gas received by Phillips for processing.

AGO 801916

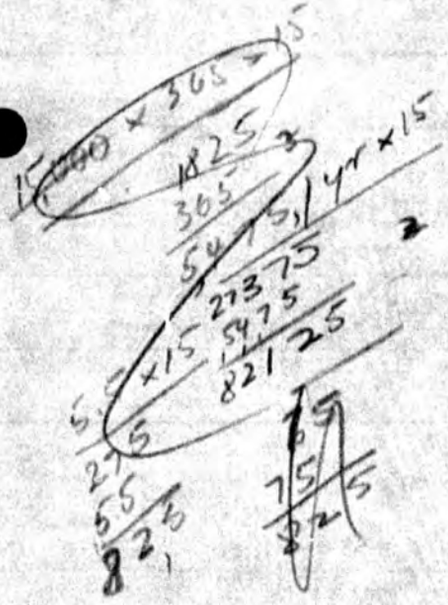
* This indicates two standards, i.e., the State continues to be charged 5.5/Mcf and not 10¢ or 20¢.

* cont'd

Try and get a reasonable explanation! This is very inconsistent.

"New" contract would provide

Quantity: APC would take up to all of the royalty gas available. This means APC would not be required to purchase all royalty gas.



How does this jive with their previous argument that they need new reserves and supplies to service their existing customers? That the royalty gas amount (15M-17M cf/day) available from the NC Inlet field was just the right amount needed to supplant their loss of Kenai gas field supplies?

APC "proposal" p 4,5

"Commissioner's proposal in concept"

15,000 × 365 = 15
1825
365
5475 1 yr × 15
27375
5475
82125
5.5 × 15
275
55
82.5
65
75
82.5

AGO 801917

Delivery Point: On Shore - at or near Phillips' pipeline tap which delivers gas to the Tesoro refinery.

Price: A) (1) To July 1, 1978 64.65¢/Mcf

(2) July 1, 1978 - July 1, 1979 the higher of (a) 66.65 ¢/Mcf, or

(b) price State would have received had it continued to take its royalty gas in value, or

(c) the highest price paid for any purchaser in the Upper Cook Inlet (within a 100 km radius of Phillips' platform) area for gas of similar quality, gas & similar conditions of delivery.

(3) July 1, 1979 and each succeeding 12 month period the higher of

(a) the previous year's price plus 2¢/Mcf, or

(b & c) above

AGO 801918

B)(1) An additional 10¢ (20¢ if the added compression facilities have been installed) for gas gathering costs, to point of delivery including dehydration and compression. These charges would increase 6% annually.

(2) Additional charges for future compression facilities which may be required and installed in proportion to ~~the~~ gas received. (Interestingly, the proposed contract calls for such additional costs under B)(3) to be verified by the State, which would seem to indicate that in this instance Phillips would agree to "jurisdiction" by the State). (To be consistent with 7.2, should this be removed?)

Term: Same as 76-1 Contract

Terminations

~~Remove~~ Same as 76-1 contract, which seems absurd since APC would never take delivery on-shore! What do they mean by "... unable to make satisfactory arrangements to take delivery of the gas."?

AGO 801919

Conditions

Precedent: Provision providing that Phillips would not come under the jurisdiction of the FPC or APUC or APC. (7.2 of Article VII).

Miscellaneous: assignments of interest by APC may be made "... to conform with its (APC) various financing documents or as may be desirable to Buyer (APC) as to its (APC) commonly owned affiliate or subsidiary." (Who are they?

AGO 801920

APC in a memo to file dated 3/10/77 made a very interesting point I think by stating that the 10¢ transportation/gathering charge Phillips would charge us still much cheaper than any alternative which exists to them or to the State for that matter, other than possibly bad publicity within the State.

The APUC in its Order No. 3, Docket U-75-68 (12/17/75) ^(p 10) states that they believe the commingling of cheaper gas with more expensive NC Inlet royalty gas and averaging the cost will generally amount to 2-5¢/Mcf/mo. for the customers of APC.

The same order also states that if the provisions allowing flow through of costs was not used by August 1, 1976 the APUC would commence an investigation to determine the non-use & whether the provision should be deleted from the tariff of APC. (See Sept 29, 1976 Letter to APUC

AGO 801921

a letter of APC to APUC dated Sept. 29, 1976 states that the contract with the State (76-1) could not be carried out because

Still need to check if it was ever appr. by Leg.

(1) APC would have to pay State the highest price within a 100 km radius (they had hoped no more than the price of gas liquefied for export)

(2) - APC would have to take 100% of royalty gas;
- They do not have sufficient sales on the North Kenai Rd for ~~the~~ full amount;
- On the other hand, they do not have facilities to interconnect ~~p~~ with their anchorage line; and
- They have been unable to work out an ~~exchange~~ agreement ~~agreement~~ ~~wi~~ for an exchange ~~f~~ with Kenai gas.

AGO 801922

(3) The contract term is limited to 6/30/84 (instead of the life of production as APC would desire) which APC claims is too short to invest in the facilities which are required.

The Sept 29, 1976 letter also indicates that Phillips wanted to have APC fund the first phase ~~to end~~ of a compressor station on the platform (appx $5MM) in return for their delivering the royalty gas to shore. APC countered with an offer that they would

- pay a pro-rata share for compression (volume) with a right to discontinue after a year's notice; and
- resell any "excess" royalty gas back to Phillips for the same price they would have paid to the state; and
- forego taking royalty gas if and when the pipeline capacity throughput was limited (a standby gas supply to make this

AGO 801923

above possible had not been found, and it was mentioned that APC might have to build a pipeline from their Anchorage line to the delivery point on shore to guarantee such stand by volumes as were necessary)

The AG (Will Gordon) in a memo to Jay Martin, dated 3/7/77, determined that the APUC would not have jurisdiction over Phillips pipeline because Phillips does not fall into the category of "a 'utility' nor 'public utility' within the meaning of the Public Utilities statute, because it will not be furnishing transmission service to the 'public' or the 'Alaska public.' Phillips would be furnishing transmission service to the State."

(Is language necessary to change this ??)

AGO 801924

The lease with the State provides that the royalty gas has to be taken in the field

The application for a r-o-w permit (2/15/68) to build 2 10" gas pipelines and appurtenances from platform to shore could be "used" to demonstrate that the pipeline is for public use, since "public" was not crossed out in the application (although it could have been).

AGO 801925

- Phillips has a contract with Tokyo Gas and Tokyo Electric which expires 6/1/84 which is supplied from the North Cook Inlet gas field (and the State's 1/8 royalty).

Fackler suggests in his Nov. 19th draft memo that the contract terms for the State should not exceed the Phillips contract terms above (which, I guess, means that the commitment of our royalty gas should not run beyond 6/1/84), and that contract terms for the State should also include a provision to protect the State if Phillips' production is terminated for any reason.

AGO 801926 -A

- Fackler's memo of Nov 19 indicates that APC (ANG) expected to pay its proportionate share of additional transportation or compression costs either in the form of contributing capital or paying higher transportation charges per Mcf or through the reducing or taking of royalty gas within

Nov. 19th memo mentions that Phillips had raised the issue of the APUC classifying their pipeline (from platform to LNG plant) as a utility (if it transports gas for a third party (APC), and that Phillips would not transport the gas if they came under APUC jurisdiction

The draft for a proposed ~~X~~ North Cook Inlet royalty gas sales agreement, dated 12/7/75, [redacted] stipulates that neither Phillips (nor Union) shall come under APUC or any other regulatory [redacted] authority as a result of the sale of royalty gas to APC. If such regulatory jurisdiction were ever asserted or implemented the agreement would be terminated.

AGO 801927

The ~~draft~~ "Memorandum of Understanding" (12/7/75) draft states that "APC will receive the State royalty gas

only to the extent it may be available without additional investment for transmission (or compression) by Phillips..."

This is subsequently qualified by providing that if any investments were necessary to allow for continued delivery of the State's royalty gas APC would have the option

① to participate equitably in such an investment, or

② to pay a mutually acceptable price per Mcf or per month, or

③ to terminate the agreement to take the State's royalty gas.

(See Faehler's Nov. 19th memo which also covers this).

AGO 801928

(John Horn) "complicating matters"

- Phillips stated the following in their Jan 21, 1976 letter to APC
  - That while a 5.5¢/Mcf figure has been used to establish the wellhead value for purposes of paying royalty and taxes, it did not represent the appropriate differential (transportation + compression). They did not say what the appropriate figure was or should be. neither
  - That Phillips nor any of its facilities could be subjected to the possibility of being classified as a public utility by the APUC, and that without an assurance to that effect no agreement would be entered into

AGO 801929

  - The "exchange" of gas from the North Cook Inlet field for gas from the Kenai gas field, suggested by APC, would have to be worked out between APC + Marathon, and Phillips would

not be a party to such an arrangement

- APC advised Union, Marathon and Phillips on December 12, 1975 that the royalty board (December 10 meeting) had authorized the Commissioner of NR to negotiate the sale of North Cook Inlet gas field royalty gas to APC

- The December 10 Royalty Bd ~~was~~ vote on the above was unanimous, although Anon Tussing raised the question whether APC had tried hard enough to get gas elsewhere. They APC then asked Union and Marathon (December 12, 1975 letters) if they were willing to offer APC like "deals" as the royalty gas they were negotiating for (i.e.,

50 Bcf
15 MMcf/day
55.8¢/Mcf (50.25¢/Mcf + 5.55¢/Mcf transportation)

AGO 801930

- Marathon declined (December 19, 1975), but came up with a proposal for a short-term contract similar to their existing contract for an additional

What happened?

supply of gas (up to 5 Bcf) for one year to May 1, 1978 (whichever occurred first) at a price of 55.8¢/Mcf

— APC letter of 2/3/76 indicates that they now felt that they would have to build their own pipeline from the LNG plant to their pipeline rather than to rely on "paper exchanges" as suggested earlier

— This they argued would require a longer term though (the Royalty Sa had proposed a 7yr period to June 1, 1984) since ~~they~~ it would ~~to~~ be impractical for APC to amortize a pipeline over such a short time. They asked to receive a contract for royalty gas for the life of production from the North Cook Inlet Gas Field.

AGO 801931

— Homer Electric Association also applied for the North Cook Inlet gas field royalty gas (Feb 23

- Royalty Bd meeting, and APC letter to Homer Electric Ass'n of 2/25/76 letters from APC to Jay Marlin of 2/27/76 and 3/9/76). Phillips Petroleum and Pacific Alaska LNG also applied for the NC Inlet field royalty gas.

- Homer Electric Association was subsequently made an o/p by K.U.S.G for needed gas at a considerably lower price than the royalty gas; $5.87/Mcf vs. 418.24¢/Mcf

- Can undated memo entitled "Commissioner's Proposal in Concept" states that ~~purchaser~~ (APC) would be responsible for measurement costs, and any compression or dehydration costs if or when nec.

AGO 801932

- As of APC's ~~their~~ letter dated 4/9/76 they intended to build a pipeline from the P-M LNG plant to their existing Anchorage line.

— A contract (76-1) was executed between the Royalty Bd and APC (6/4/76) with the following provisions:

Quantity: All royalty gas available, when and as available.

Delivery Point ~~and~~

~~Delivery Pressure~~ :— D Point shall be the same for APC as it has been for State. ~~(This appears to be the platform by since a prepared gas gathering agreement between APC + Phillips states that~~ "APC will accept said royalty gas at or near wellhead ~~[illegible]~~

(over) *

*in the North Cook Inlet Field..."

Price: ① To July 1, 1977 — 55.5 ¢/Mcf

② July 1, 1977 — July 1, 1978 — ⓐ 60.36 ¢/Mcf

ⓐ or price State would have received had it continued to take its royalty gas in value,

ⓒ or the highest price paid by any purchaser in the Upper Cook Inlet area (within a 100 km radius of Phillips' platform) for similar quality gas + similar conditions of delivery.

60.36
55.5
4.86
60.30 × 2
120.60
60.30

60.36
2
62.36
2
64.36

③ July 1, 1978 and each succeeding 12 months period the higher of

ⓐ the previous year's price plus 2 ¢/Mcf, or

(b+c) above.

AGO 801933 - 4

(This appears to be the platform since a proposed gas gathering agreement between APC and Phillips states that the contract between the State and APC provides that"... APC

Gregg's memo of May 8, 1976 to Fred Brown (p 2) confirms this.

However, a memo from Don Wold to Guy Martin dated 2/14/77 states that APC ~~[redacted]~~ "must take delivery from Phillips near the terminus of the Phillips terminus of the Phillips pipeline located near the North Kenai Road..." according to the 76-1 contract. (I don't think he is correct, but double check)

AGO801933-B

Term: Effective upon approval by the Legislature
Expires: July 1, 1984

Termination Clause: Allows APC to terminate the contract within 30 days of written notice to State if APC is unable to make satisfactory arrangements to take delivery of the royalty gas.

A suggested gas gathering agreement between APC and Phillips provides that ~~the~~ unless the contract ~~with~~ Between the State and APC is amended to accommodate Phillips' ~~could be terminated.~~ the "agreement" between APC and Phillips could be terminated.

AGO 801934

- Gas Gathering Agreement between APC + Phillips provides for, and states among other things that

  - APC will accept delivery of the royalty gas at or near the wellhead

  - Phillips is willing to gather the royalty gas for APC and deliver it at a mutually agreeable point near the Kenai LNG plant

  - Phillips will need to provide additional compression capacity to handle the royalty gas through its gathering system (they have to increase production to meet their commitments), and that APC can't justify participation in the installation of additional compression capacity, and thus would have to

AGO 801935

the delivery of royalty gas as it would become available from time to time.

- Added supply of royalty gas would be used to service existing ~~customers only~~ and potential new customers in the vicinity of the Kenai LNG Plant only for the above stated reason (amount of gas not sufficient to allow for participation in adding additional compression capacity).

- Point of ~~delivery~~ shall be at or near the existing pipeline tap now used to deliver ~~Phillips~~ gas from the Phillips pipeline to the Tesoro refinery in the general vicinity of the Kenai LNG plant on over the North Kenai Road. (This is quite different from contract with State, where the delivery point is the wellhead (platforms))

AGO 801936

* In a different portion of the "agreement" the point of delivery is to be:
"...at the juncture of APC's facilities and Philips' facilities located near the pipeline tap serving the Tesoro refinery...."

AGO 801936-B

- Odorization of gas shall be APC's responsibility, (and Phillips shall be held harmless).

- APC shall pay Phillips 10¢/Mcf for delivery from platform to delivery point and for dehydration (which is involved in dehydration?) This 10¢ charge is to increase by 6% annually

- APC shall pay Phillips in addition to the above gathering charge a compression charge of 10¢/Mcf. This, too, would increase by 6% annually.

- APC shall pay Phillips (in addition to the above) a mutually agreeable charge for added compression when and if it is necessary, based on APC's share of added volume

- In addition APC shall reimburse Phillips ~~in~~ in the ~~addition to the above~~ proportion of deliveries made to APC by Phillips

AGD 801937

- of any new or increased fees, charges, taxes, etc. applicable to gathering of the gas (including compression) which would be imposed on Phillips prior to delivery of royalty gas to APC.

- Phillips by delivering royalty gas to APC does not "... render any service to or for the public," i.e., will not become a utility subject to regulation.

- APC makes the material representation to Phillips that Phillips ~~would~~ will not be subject to regulation by the FPC or APUC.

A/GD 801938

- In a letter to Don Wold dated 2/2/77 APC first mentions the "desirability" to have the State take deliverability of its royalty gas onshore so as to avoid the necessity for APC to negotiate a seperate agreement with Phillips.

- The letter also indicates that they would not be committed to install a pipeline connecting to their anchorage line; that they would accept only such gas as they can readily re-sell up to 100% of royalty gas which is available (The reason for this is cited as the shortness of the contract; i.e., June 1, 1984 vs. life of production, which is what APC wants

The rest to be royalty gas in value to Phillips

- The same letter also indicates that they would pay the proportionate share of additional compression facilities Phillips' were to install at a future time.

AGO 801939

scomm

#16:5

APC'S VARIOUS GAS CONTRACTS

CONTRACTS/AGREEMENTS BETWEEN U-M AND APC

Anchorage Contract
North Kenai Road Contract

CONTRACTS/AGREEMENTS BETWEEN ALASKA PIPELINE COMPANY AND ANCHORAGE NATURAL GAS/ALASKA GAS AND SERVICE COMPANY

UTILITY SERVICE CONTRACTS BETWEEN APC

AND

FORT RICHARDSON AND
FORT RICHARDSON AND EAFB

AGO 570377

May 21, 1977

Contracts/Agreements between U-M and APC

1. ✓	May 13, 1960	Gas Purchase Contract (Anchorage)
✓	January 1, 1972	Amendment of Gas Purchase Contract
✓	January 1, 1975	Amendment of Gas Purchase Contract (CURRENT CONTRACT)
2. ✓	May 1, 1967	Gas Sales Agreement (North Kenai Road)
✓	March 12, 1976	Amendment to Gas Sales Agreement

The May 13, 1960 contract as amended is the "main" contract. Everything refers back to it, including the North Kenai Gas Sales Agreement dated May 1, 1967, as amended March 12, 1976.

The price for the North Kenai Road gas is the same as the May 13, 1960 contract as amended, PLUS 1-1/2 cents per Mcf. Anything over the 10,000,000 Mcf amount also has the "Special Deliverability Charge" of 19-1/2 cents per Mcf.

Therefore, APC should be paying U-M 45 cents per Mcf at the moment for gas from the Kenai Gas field being delivered to the North Kenai Road area. (Marathon refers to a cost of 45.7¢ per Mcf. I have no idea what the .7¢ is for or how they arrived at it unless the "Special Deliverability Charge" has been raised, which is quite possible).

Current Price according to January 1, 1975 amended contract to May 13, 1960 "Gas Purchase Contract"	24¢
Special Deliverability Charge	19.5¢
Over and Above "Anchorage" contract price being charged for North Kenai Road deliveries	*1.5¢
	45.0¢

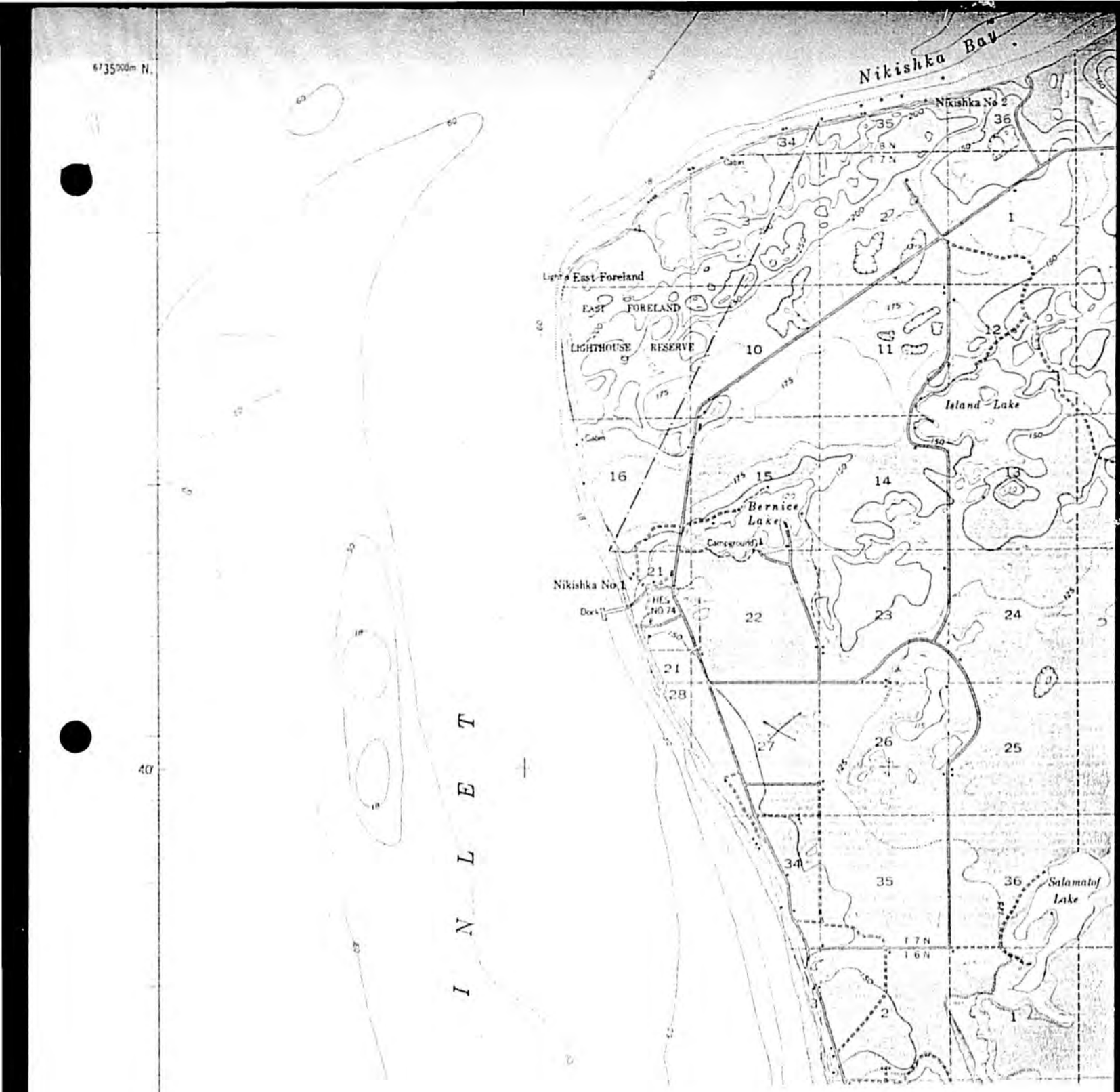
*This is the figure which now and then is referred to as a "transportation" charge, which in fact it might be. However, nothing in the contract or amendment indicates or even implies that it is a transportation cost. It simply reflects a cost over and above that cost for gas contracted for by APC for Anchorage.

Contracts/Agreements between Alaska Pipeline Company and Anchorage Natural Gas/Alaska Gas and Service Company

3. ✓	December 9, 1960	Gas Sale Contract
✓	October 16, 1962	Amendment to Gas Sale Contract
✓	October 15, 1963	Amendment to Gas Sale Contract
✓	April 1, 1970	Amendment to Gas Sale Contract
✓	October 3, 1972	Amendment to Gas Sale Contract
✓	August 27, 1973	Amendment to Gas Sale Contract

4. ✓ Utility Service Contracts between APC and Fort Richardson and Fort Richardson and EAFB

✓ have



6735000m N.
Nikishka Bay
Nikishka No 2
Light East Foreland
EAST FORELAND
LIGHTHOUSE RESERVE
Island Lake
Bernice Lake
Campground
Nikishka No 1
Dock
HES NO 74
Salamatof Lake
T 8 N
T 7 N
T 6 N
INLET
40'

THE FOLLOWING DOCUMENT(S) MAY NOT FILM LEGIBLY BECAUSE OF POOR QUALITY OF THE ORIGINAL.

1/1/72
amendment

KG/Kenco

CHANGES IN GAS PURCHASE CONTRACT

1. Effective date 1-1-72.

2. Change contract year (Oct. to Oct.) to Calendar Year Jan. thru Dec.

3. Change reserves from 240,000,000,000 to 550,000,000,000 unless in 1981 if remaining reserves are more than 12-years' supply based on 1980 usage, then reserves reduced to remaining 12 years.

4. Change in delivery points from mouths of wells to a central Buyer's master meter.

5. Change in delivery pressure from 700 psi prior to August 14, 1971 to 900 psi prior to December 31, 1972; and from 500 psi after 1971 to 700 psi from 1-1-73 to 12-31-75 and 500 psi thereafter.

6. Change in price

Old Contract	New Contract
First 8 billion cu. ft. per year 24¢	25¢
All additional volumes 16¢	17¢ but not less than 21¢ average
Escalation 1¢ starting October 1972 and 1¢ every 5 years thereafter	1¢ starting 1-1-74 2¢ starting 1-1-76 3¢ starting 1-1-81 After 1986 not less than 27¢ or average delivered gas f.o.b. Kenai Gas Field received by Seller during 1985 from all new sales made to other than APC after 1972 but sales to others on which average calculated shall be at least 1/4 of quantity of gas delivered to APC

7. Term – From September 30, 1987 changed to December 31, 1992.

8. Change in Quality of gas in water content to not more than 4# water per million cu. ft. of gas (dehydrated gas). Prior contract APC provided own dehydration.

File

AGO 570380



ALASKA PIPELINE COMPANY

P. O. BOX 6554 • HOUSTON, TEXAS 77005

June 15, 1971

Union Oil Company of California
Union Oil Center
Los Angeles, California 90017

and

Marathon Oil Company
539 South Main Street
Findlay, Ohio 45840

Gentlemen:

Reference is made to that certain letter agreement between us dated October 1, 1967, concerning special handling of unused gas reserves under our "Kenai-Nikiski Agreement" as defined below.

Reference is also made to that certain "Amendment of Gas Purchase Contract" (amending the Gas Purchase Contract dated May 13, 1960) between Union Oil Company of California ("Union"), and Marathon Oil Company ("Marathon"), as "Seller", and Alaska Pipeline Company ("Alaska"), as "Buyer", which said Amendment is dated effective January 1, 1972, and is herein referred to as "Anchorage Service Area Agreement". Executed copies of the Anchorage Service Area Agreement are transmitted to you herewith.

Reference is also made to that certain "Gas Sales Agreement" dated and effective as of May 1, 1967, between Union and Marathon, as Seller, and Alaska, as Buyer, involving certain taps and deliveries of gas off of Seller's Kenai-Nikiski Pipeline until an aggregate quantity of 10,000,000 Mcf of gas has been delivered and purchased thereunder, or for a period of ten (10) contract years, whichever first occurs (herein referred to as "Kenai-Nikiski Agreement").

This letter confirms our further agreement as follows:

(1) Effective January 1, 1972, the above-mentioned letter agreement dated October 1, 1967, is terminated and the further agreements set out below become effective.

ALASKA PIPELINE COMPANY

P. O. BOX 6554 • HOUSTON, TEXAS 77005

(2) Upon the termination of the Kenai-Nikiski Agreement, in whatever way it is terminated, the quantity of gas reserves specified in Section IIA(1) of the Anchorage Service Area Agreement, shall be increased by the amount of gas, if any, which was not taken by Alaska under the Kenai-Nikiski Agreement.

(3) Any gas paid for but not taken by Alaska under the provisions of the Kenai-Nikiski Agreement may, but only upon the termination of said Agreement, be taken by Alaska during the remaining term of the Anchorage Service Area Agreement without further payment, except that Alaska shall pay the differential in applicable taxes described in Section 5.2 of the Kenai-Nikiski Agreement, if any, between that existing when such payments were originally made and that applicable at the time of such taking.

(4) Any gas taken by Alaska under Paragraph (3) above, shall be at the delivery points and under the technical specifications applicable to gas deliverable under the Anchorage Service Area Agreement.

Your execution of the enclosed copy of this letter and returning the same to us evidences your agreement to the above.

Very truly yours,

ALASKA PIPELINE COMPANY

By _____
Vice President

Accepted and Agreed to
as of the date of this letter:
UNION OIL COMPANY OF CALIFORNIA

By _____
Attorney-in-Fact
MARATHON OIL COMPANY

By _____
R. E. McMILLEN, SENIOR VICE PRESIDENT

AGO 570382

THE PRECEDING DOCUMENT(S MAY NOT FILM
LEGIBLY BECAUSE OF POOR QUALITY OF THE
ORIGINAL.

ATTACHMENT 1

AMENDMENT OF GAS PURCHASE CONTRACT

THIS AGREEMENT, made and entered into effective as of the 1st day of January, 1972, by and between UNION OIL COMPANY OF CALIFORNIA, hereinafter sometimes referred to as "Union," and MARATHON OIL COMPANY (formerly The Ohio Oil Company), hereinafter sometimes referred to as "Marathon," both companies hereinafter referred to collectively as "Seller" and sometimes herein individually as "seller" and ALASKA PIPELINE COMPANY, hereinafter referred to as "Buyer,"

W I T N E S S E T H:

WHEREAS, Buyer and Seller are parties to that certain Gas Purchase Contract dated May 13, 1960, as amended and modified, covering the purchase and sale of natural gas from certain properties of Union and Marathon located on the Kenai Peninsula, Alaska; and

WHEREAS, the parties desire to further amend said Gas Purchase Contract, as heretofore amended and modified, as of the effective date, stated above;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements herein contained, the parties hereby amend that certain Gas Purchase Contract between Buyer and Seller dated May 13, 1960, as heretofore amended and modified, and agree as follows:

1. Each and every prior amendment to, or modification of that certain Gas Purchase Contract dated May 13, 1960, which has been entered into or agreed to by any party hereto, and Exhibits "A" and "B" of said agreement, are hereby cancelled and shall be of no further force or effect as of the effective date of this Amendment.

2. Exhibits A, B, C and C-1, attached hereto, are hereby added to and made a part of said Gas Purchase Contract dated May 13, 1960.

3. Commencing with the word "WITNESSETH:", on the first page of said Gas Purchase Contract and including Pages 2 through 15 thereof, said contract is hereby amended to read as follows:

WHEREAS, Alaska Public Service Corporation (formerly named Anchorage Natural Gas Corporation), hereinafter sometimes referred to as "Anchorage", has held and now holds a franchise from the City of Anchorage, Alaska, and a Certificate from the Alaska Public Utilities Commission, to distribute gas for domestic, commercial and industrial purposes within the City of Anchorage; which is more particularly defined in City of Anchorage Ordinance No. 1347, and holds or may from time to time acquire other such franchises and certificates for rendering said services within the area outlined and described, respectively, in Exhibit C and Exhibit C-1, and said area is hereinafter referred to as "Service Area"; and

WHEREAS, Buyer owns and operates a gas transmission pipe line system extending from the Kenai Unit Area, Third Judicial Division, State of Alaska, to said Service Area; and

WHEREAS, Buyer and Anchorage have entered into an agreement under which Buyer has agreed to sell, deliver and furnish to Anchorage and Anchorage has agreed to purchase, take and receive from Buyer, all of Anchorage's requirements for gas pursuant to the terms thereof and of this Agreement; and

WHEREAS, Union and Marathon each own or control oil, gas and mineral leaseholds and/or lands within the Kenai Unit Area, which leaseholds and lands are more particularly described in Exhibit B attached hereto and made a part hereof, and each has a supply of gas by virtue of its ownership or control of said leaseholds and lands which, together with certain other gas that Union and/or Marathon may from time to time purchase from co-owners of interests in said leaseholds and lands, it is willing to commit by this contract to sell to Buyer within the total volume limitation hereinafter provided; and

WHEREAS, Buyer desires to purchase from Seller all of its gas requirements for the Service Area, as said "Service Area" is hereinafter defined.

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements herein contained, the parties hereto do hereby covenant and agree as follows:

I. DEFINITIONS

Except where the context otherwise indicates another or different meaning or intent, the following terms are intended and used herein and in Exhibit A, attached hereto and made a part hereof, and shall be construed to have meanings as follows:

(1) The term "day" shall mean a period of twenty-four (24) consecutive hours beginning and ending at eight o'clock a.m., Alaska Standard Time.

(2) The term "month" shall mean a period beginning at eight o'clock a.m. on the first (1st) day of a calendar month and ending at eight o'clock a.m. on the first (1st) day of the next succeeding calendar month.

(3) The term "year" shall mean a period of twelve (12) consecutive months beginning on the first day of January of any calendar year.

(4) The term "Gas" shall mean natural gas meeting the standards set forth in Section C of Exhibit A hereof.

(5) The term "Mcf" shall mean one thousand (1,000) cubic feet.

(6) The term "British thermal unit" (Btu) is defined as the amount of heat required to raise the temperature of one (1) pound of water from fifty-nine degrees (59°) Fahrenheit to sixty degrees (60°) Fahrenheit at a pressure of fourteen and sixty-five one hundredths (14.65) pounds per square inch absolute.

(7) The term "Seller's Delivery Capacity" shall mean the maximum quantity of gas which can be withdrawn (subject to any applicable State or Federal laws and statutes and any valid rules, orders and regulations of any State or Federal regulatory body) daily from the leaseholds and/or lands of Seller covered by this Agreement and which is available for delivery to Buyer for use in the Service Area at the point or points of delivery hereunder at the pressure provided for in Article VI hereof.

(8) The term "Service Area" shall mean the geographical area outlined on Exhibit C and described in Exhibit C-1 attached hereto and made a part hereof.

(9) The term "Buyer's Requirements" shall mean Buyer's total requirements for gas sold and delivered by Buyer from its system in the Service Area for resale, use or consumption in said Service Area.

(10) "Kenai Unit Area" as used herein means that area described in Unit Agreement for the Development and Operation of the Kenai Unit Area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated May 1, 1959, and revisions thereto.

II. SCOPE OF AGREEMENT

A. Service Area

(1) Subject to and in accordance with all of the terms, conditions and limitations set forth hereinafter and in Exhibit

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A hereof, Seller agrees to sell and deliver or cause to be delivered to Buyer, and Buyer agrees to purchase and receive from Seller, all of Buyer's Requirements of gas for the Service Area during the term hereof up to a maximum total quantity of Five Hundred Fifty Billion (550,000,000,000) cubic feet of gas. Said maximum total quantity of gas is hereinafter referred to as "Seller's Gas Reserve", and shall be produced from the leaseholds and/or lands described in Exhibit B.

Provided, however, that if the total deliveries of gas delivered hereunder during the year commencing January 1, 1980 and ending December 31, 1980 divided into Seller's remaining recoverable reserves committed to this contract (550,000,000,000 cubic feet of gas less the quantity of gas theretofore delivered hereunder), as of January 1, 1981, is more than twelve (12), then upon written notice by Seller to Buyer given by January 1, 1982 and not thereafter, Seller's Gas Reserve shall be reduced to a quantity of gas which is twelve (12) times the total quantity of gas so delivered hereunder during such year beginning January 1, 1980 and ending December 31, 1980.

(2) Seller shall, with due diligence, operate the lands and leaseholds subject to this Agreement in a skillful and reasonably prudent manner to the end that Seller's Delivery Capacity and Seller's Gas Reserve shall be maintained from time to time during the term hereof at a volume necessary to satisfy Buyer's Requirements. On or before the first day of August

of each year during the term hereof, Buyer shall notify Seller of Buyer's maximum daily firm load requirements and Buyer's maximum daily interruptible load requirements during the twelve-month period beginning the first day of August of the following year, furnishing Seller with evidence satisfactory to Seller of such requirements. "Buyer's maximum daily firm load requirements" shall mean the maximum quantity of gas the Buyer is required to deliver during any one day of the aforesaid twelve-month period to all purchasers to whom Buyer is obligated to deliver gas without any right to interrupt such deliveries at any time. "Buyer's maximum daily interruptible load requirements" shall mean the maximum quantity of gas that Buyer is required to deliver during any one day of the aforesaid twelve-month period to all purchasers to whom Buyer is obligated to deliver gas, subject only to the right of Buyer to interrupt such deliveries during any period when Buyer does not have the gas available for delivery due to its firm load requirements. Seller shall then notify Buyer on or before the first day of October following receipt of such notice of one of the following:

(i) Seller's Delivery Capacity is equal to 110% of such requirements, furnishing Buyer with evidence satisfactory to Buyer of such delivery capacity, or

(ii) Seller does not have such delivery capacity and will not attempt to provide such capacity, or

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(iii) Seller does not have such delivery capacity, but will attempt to provide such delivery capacity of 110% of such maximum daily load requirements on or before the first of April next succeeding the date of such notice.

In the event Seller gives Buyer the notice called for in (ii) or (iii) above, then Buyer shall be free, from the date of receipt of such notice from Seller that (ii) applies, or from the first of April in the event (iii) applies and Seller has not then provided such delivery capacity, to contract with others for the purchase of gas up to 2500 Mcf per day, or the amount by which the current Seller's Delivery Capacity (as stated by Seller to Buyer) is less than Buyer's maximum daily load requirements, whichever is the greater; provided, however, that to the extent of Seller's ability to perform, the annual daily average quantity which Buyer is obligated to take hereunder (i.e., Buyer's Requirements expressed as a daily volume), shall not in any event be reduced by more than 2500 Mcf. Nothing herein shall be construed to require Seller to drill additional wells in order to increase Seller's Delivery Capacity nor shall Seller be required to produce any well or wells in a manner which, in Seller's sole judgment, would not be in accordance with prudent gas field operating practice.

(3) Buyer agrees to purchase solely from Seller all of Buyer's Requirements for gas in its operations in and for resale in the Service Area up to the total quantity of Seller's Gas Reserve, as hereinabove defined, and subject to the conditions hereinafter contained. To the extent that Buyer's Requirements exceed Seller's Gas Reserve, and to the extent that Seller has reserves available and uncommitted to others in addition thereto by virtue of its ownership or control of the leaseholds and lands described in Exhibit B, Seller is hereby given the right and option to commit such additional reserves to this contract sufficient to meet all or a portion of Buyer's excess requirements. Seller shall, upon written request from Buyer to be made not more frequently than one time per year, certify to Buyer that the gas remaining to be delivered hereunder from Seller's Gas Reserve is available from the leaseholds and/or lands described in Exhibit B, and that said quantity of gas is free of commitments to others. Seller shall furnish to Buyer with such certificate a report of an Independent Geologist substantiating such certification, which Independent Geologist (employed for the purpose of rendering such report) shall be one designated by Seller.

In the event that Seller should elect not to commit additional gas reserves to satisfy all of Buyer's Requirements, Buyer shall have the right to contract with others for the

purchase of sufficient gas to meet such requirements. In the further event that Buyer's Requirements subsequently exceed the gas reserves then committed to this Agreement by Seller, plus any gas committed by others, Buyer agrees to again give the Seller the right and option to supply such requirements by committing additional gas reserves within the Kenai Unit Area, subject to the terms hereof.

Buyer agrees that during such years as it is purchasing gas from others for use in its operations in and for resale in the Service Area it will continue purchasing from Seller during such years a quantity of gas equal to Seller's remaining recoverable reserves committed to this contract (Seller's Gas Reserve, less gas delivered hereunder) divided by the number of years remaining on the term of this agreement; provided, however, in the event Buyer's Requirements shall decrease in any remaining year of the contract term, then Buyer agrees to purchase from Seller the same proportion of Buyer's Requirements of gas for such year as was purchased from Seller during the preceding year.

B. Special Supply of Gas for Use Outside of Service Area

(1) The parties agree that, apart from the gas currently sold by Seller to Buyer for use in the Service Area, Seller shall sell to Buyer and Buyer shall purchase and receive from Seller a special supply of gas for use outside of the Service Area upon the following terms and conditions:

(a) The special supply shall not exceed an aggregate of five (5) billion cubic feet of gas.

(b) Buyer shall notify Seller on or before the first day of August of each year during the term hereof of Buyer's Maximum Daily Need during the twelve-month period beginning the first day of August of the following year. "Maximum Daily Need" as used herein shall mean the maximum quantity of gas, if any, as set forth in such notice, which Buyer desires to purchase from Seller on any day or days of said period for sale or use outside of the Service Area, but shall not exceed 1000 Mcf per day. Seller agrees to have available for delivery and sale to Buyer on each day during such twelve-month period, a quantity of gas equal to such Maximum Daily Need. Buyer agrees to purchase from Seller during such twelve-month period an annual quantity of gas equal to the lesser of (a) the total requirements of Buyer for gas sold or used by Buyer outside of the Service Area or (b) the applicable Maximum Daily Need multiplied by 182.5.

(c) The aggregate quantity of gas delivered to Buyer by Seller under this Section IIB shall be deducted from the maximum total quantity of Five Hundred Fifty Billion (550,000,000,000) cubic feet, designated "Seller's Gas Reserve" in Section IIA(1) hereof.

(2) The parties agree that, with the exceptions of Sections 7 and 9 of Article I and Article IIA hereof, all other terms and provisions of this Gas Purchase Contract shall apply to the sale and delivery of gas chargeable to the special supply. Volumes of gas delivered under this Section IIB shall be added to volumes of gas delivered to Buyer for Buyer's Requirements in the Service Area in determining the charges to Buyer for all gas delivered hereunder.

(3) Except for and subject to the provision contained in Paragraph (1)(c) of this Section IIB, said Section IIB may be terminated as follows:

(a) Buyer may, by written notice to Seller, terminate this Section IIB whenever, in Buyer's sole judgment, Buyer has no further need for such special supply of gas. Such termination shall be effective at 8:00 a.m., Alaska Standard Time, on the first day of the month next occurring after ninety (90) days notice to Seller.

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(b) This Section IIB shall automatically terminate as of the end of any twelve-month period beginning on any first day of August if, during such period, Buyer fails to purchase at least 135,000 Mcf pursuant to this Section IIB, unless during such period gas purchased pursuant to this Section IIB is the sole source of gas utilized by Buyer for sale or use outside the Service Area.

C. Use of Seller's Delivery Capacity Outside of Service Area.

The parties agree that, upon any day when the current Seller's Delivery Capacity (as stated by Seller to Buyer) exceeds Buyer's Requirements for such day, such excess may be used by Buyer at Buyer's option outside the Service Area, and the quantity so used shall be deducted from Seller's Gas Reserve designated in Section IIA(1) hereof, and shall be added to volumes of gas delivered to Buyer for Buyer's Requirements in determining the charges to Buyer for all gas delivered hereunder. Gas may be taken under this Section IIC whether or not gas is then being taken by Buyer under Section IIB hereof.

III. RESERVATIONS OF SELLER

Without impairment of Seller's Gas Reserve, Seller hereby expressly reserves the following rights with respect to gas in, or which may be produced from, the leaseholds and/or lands covered by this Agreement:

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(1) The right to use gas produced from said leaseholds and/or lands for the following purposes:

(a) For the development and operation of such leaseholds and/or lands owned by Seller and any other leaseholds and/or lands owned by Seller or in which Seller owns an interest located in the Kenai Unit Area.

(b) For delivery to the lessors in Seller's leases of the gas which such lessors are entitled to take under the terms of such leases.

(c) For the operation of the facilities which Seller may install in order to deliver gas hereunder in accordance with the terms hereof.

(d) For domestic use by Seller's employees employed in conducting operations in said Unit Area.

(e) For all other uses of Seller, including existing or future commitments of gas by Seller to others for any purpose whatsoever.

(2) Seller shall have the right at its option to extract, or cause to be extracted, liquefiable hydrocarbons from the gas delivered hereunder by means of processing in a plant to be located in the field or at any point along Buyer's transmission line; such right to process and extract, as herein reserved to Seller, being conditioned as follows:

(a) Not more than one such plant shall be constructed on Buyer's pipeline.

(b) The residue gas, after processing, shall have a total heating value of not less than 950 Btu's per cubic foot.

(c) Seller shall reimburse Buyer for the actual fuel consumed in the processing operation, and for a calculated amount sufficient to cover shrinkage.

(d) Seller shall provide such compression as may be necessary to make up any pressure drop resulting from such processing in excess of 50 psig.

(e) Seller shall furnish and pay the cost of installing block valves and by-pass valves required to effect delivery of gas to such plant and redelivery to the Buyer after processing.

(f) Seller agrees to indemnify and save Buyer harmless from all losses, damages and expenses which may occur or be asserted by reason of accident or occurrences resulting from Seller's operations in processing the gas delivered through the processing facilities.

IV. THIRD PARTY SALES

It is understood that with respect to natural gas in the State of Alaska, Marathon and Union are primarily engaged in exploration and production operations, the export of liquefied natural gas, the manufacture of products from and the processing

of natural gas and sales of gas at or near the point of production or processing. Neither Marathon nor Union intends to transport gas to the Service Area, sell gas to others for resale within the Service Area or to distribute gas within the Service Area either directly through its own facilities or indirectly through facilities of any subsidiary or affiliate. It is further understood that Buyer, and its affiliated companies, are primarily engaged in the business of purchasing, transporting, distributing and reselling natural gas. The parties desire that there be continuing increases in the quantities of gas produced from Seller's Gas Reserve and resold by Buyer within the Service Area and accordingly the parties have agreed to the following:

(1) Subject to the terms and conditions hereinafter set forth in Paragraphs (4), (5) and (6) hereof, each seller agrees to sell gas for resale within the Service Area exclusively to Buyer during the term hereof.

(2) If during the term hereof, either seller hereunder considers selling gas produced in the State of Alaska to a third party for its use or consumption in the Service Area, but not for resale therein (and if such sale is not excluded from this Article IV by the provisions of Paragraph (5) below or excepted from this Article IV by the provisions of Paragraph (6) below), then, before a gas sales contract is signed with such third party, such seller shall notify Buyer in writing of all the terms and conditions of such proposed sale. Buyer shall thereupon have

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the option for a period of ninety (90) days from receipt of such notice, to purchase such gas upon the same terms and conditions. The exercise of such option by Buyer shall be evidenced by written notice delivered to the seller, within the time specified. If the option is so exercised, Buyer shall then attempt in good faith to negotiate a resale of such gas to such third party. If a binding contract of sale of such gas from Buyer to such third party is not signed within ninety (90) days after such exercise of the option by Buyer, and if other gas is not available in sufficient quantity for purchase by such third party upon substantially the terms and conditions contained in the original notice, such seller may sell to such third party the quantity of gas specified in the original notice upon the terms and conditions contained in such notice. Any gas purchased pursuant to the exercise of such option may be resold, used or consumed by Buyer in the Service Area and in such event the quantity of gas thus resold, used or consumed shall be considered to be a part of Buyer's Requirements for the contract year in which such gas is delivered to Buyer and such quantity shall be considered to be produced from Seller's Gas Reserve.

(3) In the event the option is not exercised as above provided, the seller may complete such sale to such third party purchaser upon the terms and conditions set forth in the notice;

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provided, however, from and after the commencement of deliveries of such gas to such third party purchaser, Buyer's obligations to such seller under the provisions of Paragraphs (1), (2) and (3) of Section A of Article II hereof shall be partially discharged as hereinafter provided by the purchase of gas by Buyer from any party other than such seller. The partial discharge of Buyer's obligations shall be effected only under the following procedure:

(a) within ten (10) days following the first full month during which deliveries of gas have been made to such third party purchaser, such seller shall notify Buyer in writing of the aggregate amount of gas so delivered to such purchaser. Such notice shall also set forth a "Maximum Annual Exempt Quantity of Gas" which shall be equal to the greater of (i) 15 times the first month's deliveries to such purchaser or (ii) the estimated deliveries for the first twelve (12) months of such contract. Provided, however, whenever the annual deliveries of gas to a third party purchaser are increased, said "Maximum Annual Exempt Quantity of Gas" shall be revised by such seller to conform to the actual deliveries of gas to such purchaser during

the current annual period with the effect that each revised "Maximum Annual Exempt Quantity of Gas" shall thereafter govern the rights of Buyer under the following Subparagraph 3(b).

(b) Buyer may thereafter purchase from any other seller, for delivery in any one or more of the twelve-month periods remaining under this Agreement, a quantity of gas equal to, or less than the "Maximum Annual Exempt Quantity of Gas" and the annual quantity of gas so purchased for delivery in any such twelve-month period shall be credited in such year as a part of Buyer's Requirements hereunder.

(c) Any quantity of gas to be credited as a part of Buyer's Requirements in compliance with the provisions of Subparagraph (b) of this Paragraph (3) shall be considered to be produced from Seller's Gas Reserve.

(4) Any partial relief from Buyer's obligations to purchase Buyer's Requirements as provided for in Paragraphs (2) and (3) above shall not affect the commitment of Buyer to purchase gas from the party seller who does not sell gas to such third party. This agreed result implements the acknowledged "separate

interest" of Union and Marathon referred to in Article XI of this Agreement.

(5) Paragraphs (1), (2) and (3) of this Article IV shall not be applicable with respect to any sale of gas by either seller to a third party unless prior to the signing of the contract for the sale of such gas such seller knows or has reasonable grounds to believe that the gas included in such sale will be resold, used or consumed within the Service Area.

(6) It is expressly agreed that Paragraphs (1), (2) and (3) of this Article IV shall never apply to (a) any sale, use or consumption of gas for or in connection with any operation for the production of oil or gas such as, but not limited to cycling, reservoir pressure maintenance or repressuring, gas lift operations or fuel for any pump, or other field facility, (b) any use or consumption of gas for or in connection with the liquefaction of gas, any manufacturing operation in which gas or any component thereof is a raw or finished product, or gas processing of any nature whether similar or not, by either or both sellers or any affiliate of either or both sellers and (c) sales of gas by either seller which do not exceed in the aggregate per year, as to each seller separately, the greater of: (i) 250,000 Mcf, or (ii) two percent (2%) of the highest aggregate quantity of gas sold by Buyer, its subsidiaries and affiliates, in the Service Area during 1967 or any year thereafter.

V. POINT OF DELIVERY

(1) The delivery point for the gas deliverable hereunder shall be at the upstream flange of Buyer's master meter located in Section 30, Township 5 North, Range 11 West, Kenai Peninsula Borough, Seward Base and Meridian, Alaska.

(2) Title to and ownership of such gas shall pass to and absolutely vest in Buyer at the point of delivery as aforesaid.

(3) As between the parties hereto, Seller shall be in control and possession of the gas deliverable hereunder and shall indemnify and hold Buyer harmless for any damage or injury caused thereby until the same shall have been delivered to Buyer, after which delivery Buyer shall be deemed to be in exclusive control and possession thereof and shall indemnify and hold Seller harmless for any injury or damage caused thereby.

VI. PRESSURE

(1) The gas to be delivered hereunder shall be delivered by Seller into Buyer's facilities against the pressure existing therein from time to time at said point of delivery; provided, however, that Seller shall not be required to deliver such gas at a pressure (a) in excess of nine hundred (900) pounds per square inch gauge prior to December 31, 1972; (b) in excess of seven hundred (700) pounds per square inch gauge from January 1, 1973 to December 31, 1975; nor (c) in excess of five

hundred (500) pounds per square inch gauge thereafter during the term hereof. Neither Seller nor Buyer shall be obligated to install or operate compression facilities in order to deliver or receive gas hereunder, but either Seller or Buyer may do so at its option.

(2) In the event, however, that the gas cannot be delivered at the aforesaid pressures, and if neither Seller nor Buyer installs or operates compression facilities; then either party, at its option, may terminate this contract after 30 days' written notice to the other party, unless such other party advises the party giving such termination notice within said 30-day period that it elects to take steps to meet such delivery pressures.

VII. PRICE

(1) Subject to the provisions of Paragraph (2) below, the prices to be paid by Buyer to Seller for gas delivered to Buyer hereunder shall be as follows:

First 8 billion cubic feet per year	25.0¢ per Mcf
All additional volumes per year	17.0¢ per Mcf,

provided, however, that the average price for all gas delivered in any year shall not be less than 21.0¢ per Mcf. Each of the above prices, including the average price, shall be increased 1.0¢ per Mcf effective January 1, 1974, an additional 2.0¢ per Mcf effective January 1, 1976, and an additional 3.0¢ per Mcf

effective January 1, 1981. From and after January 1, 1986, the average price for all gas delivered hereunder in any year thereafter shall be not less than the greater of (1) 27.0¢/Mcf, or (2) the "average delivered price f.o.b. the Kenai gas field, received by Seller, or each of the sellers in the aggregate, during the year commencing January 1, 1985 and ending December 31, 1985, from all new sales made to buyers other than the Buyer after January 1, 1972, in significant or substantial quantities", hereinafter called the "Average Third Party Price". For the purposes of clause (2) above the Average Third Party Price shall mean the aggregate proceeds on which royalty was calculated and paid from all such new sales to others during such year, divided by the total quantity of such gas so delivered; provided, however, the aggregate quantity of such deliveries and sales to others during the year commencing January 1, 1985 and ending December 31, 1985 shall be at least one-fourth (1/4) of the quantity of gas delivered to Buyer hereunder during such year.

(2) Any sales, transactions, occupation, service, production, severance, gathering, transmission, export or excise tax, assessment or fee levied, assessed or fixed by the United States or any State or other governmental authority and taxes of a similar nature or equivalent in effect (not including income, excess profits, capital stock, franchise or general

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property taxes) in addition to or greater than those, if any, being levied, assessed or fixed on May 13, 1960, in respect of or applicable to the natural gas to be delivered by Seller to Buyer hereunder and which Seller may be liable for during any month either directly or indirectly through any obligation to reimburse others, are hereinafter collectively referred to as "additional tax". It is expressly understood and agreed between the parties that so long as the additional tax shall be in effect Buyer shall reimburse Seller for all such additional tax. In the event all or any part of such liability of Seller is not determined or not determinable by the end of any month, then such additional amount required in respect of such liability not determined or determinable shall be set forth for all such months in any calendar year in a statement to be rendered by Seller to Buyer by April 1 of the following calendar year and Buyer shall pay the amount due pursuant to such statement on or before May 1 of such following calendar year.

VIII. TERM

This Gas Purchase Contract shall continue and remain in full force and effect for a term ending December 31, 1992; provided, however, in the event Seller has after the effective date hereof and prior to December 31, 1992, sold and delivered to Buyer hereunder a maximum total quantity of gas equal to Seller's Gas Reserve as defined in Section IIA(1) hereof, then this Contract

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shall thereupon terminate unless there remain additional reserves which have been committed to Buyer by Seller. In such latter event, this Contract shall remain in effect until the expiration of such term, or delivery of such additional reserves, whichever occurs first. None of the covenants or agreements made in this Contract shall survive the expiration of the term hereof.

IX. ADDRESSES

Until Buyer is otherwise notified in writing by Union, the address of Union is and shall remain as follows:

Union Oil Company of California
909 West Ninth Street
Anchorage, Alaska ~~99503~~ 99501

and, unless Buyer is otherwise notified in writing by Marathon, the address of Marathon is and shall remain as follows:

Marathon Oil Company
P. O. Box 2380
Anchorage, Alaska 99501

and, unless Seller is otherwise notified in writing by Buyer, the address of Buyer is and shall remain as follows:

Alaska Pipeline Company
P. O. Box 6554
Houston, Texas 77005

All notices required to be given in writing hereunder shall be given to the respective parties at such addresses or such other addresses as the parties respectively shall designate by written notice, and all notices required herein to be given to Seller shall be given to both Union and Marathon.

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X. MISCELLANEOUS

(1) No waiver by either party hereto of any one or more defaults by the other in the performance of any provisions of this Agreement shall operate or be construed as a waiver of any future default or defaults, whether of a like or of a different character.

(2) This Agreement shall be binding upon and inure to the benefit of the successors and assigns of the respective parties hereto, and shall constitute a covenant running with the lands and leasehold estates covered hereby. Seller and Buyer both agree that no sale or transfer of said properties of Seller or any part thereof or of all or substantially all of Buyer's said system shall be made unless the purchaser or transferee thereof shall assume and agree to be bound by this Agreement insofar as the same shall effect and relate to the property or interest sold or conveyed. It is agreed, however, that nothing contained in this paragraph shall in any way prevent either party hereto from pledging or mortgaging its rights hereunder for security of its indebtedness.

(3) Each of the parties hereto agrees to proceed with diligence in a good faith effort to obtain and maintain in good standing such governmental authorization, certificates and franchises as may be necessary to enable it to perform its other obligations under this Agreement.

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(4) Seller grants to Buyer, so far as Seller has the right to do so, right-of-way on the leases and lands covered by this Agreement for Buyer's gathering pipe line and such other equipment as may be necessary, with full right of ingress and egress to and from said premises, and the further right to do thereon acts necessary or convenient for the carrying out of the terms of this Agreement.

XI. USE OF TERM "SELLER"

The term "Seller" is used collectively herein to refer to Union Oil Company of California and Marathon Oil Company solely for purposes of convenience, and it is the specific intent of the parties hereto that each has executed this Agreement and has contracted herein independently and to the extent of its separate interest only. It is understood that each seller company presently owns and holds an equal undivided interest in the gas to be sold under this contract and that, until further written notice from both of said companies, payment for gas delivered hereunder will be made by Buyer in equal amounts, one half of such payment to Union and one half to Marathon.

It is expressly agreed that the relation of the parties hereto is that of independent contractors and nothing in this Agreement contained, expressed or implied, nor any operations conducted hereunder, shall create or be deemed to have

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created a partnership or association between the parties hereto or any of them.

IN WITNESS WHEREOF, the parties hereto have caused this Amendment of Gas Purchase Contract to be executed this 15 day of July, 1971.

UNION OIL COMPANY OF CALIFORNIA

By _____
Its Attorney-in-fact

MARATHON OIL COMPANY

ATTEST:

By _____
Vice President

_____
ASSISTANT SECRETARY

SELLER

ALASKA PIPELINE COMPANY

ATTEST:

By _____
Vice President

_____
Assistant Secretary

BUYER

RECEIVED
JAN 24 1974
State of Alaska
Public Utilities Commission

AGO 570410

EXHIBIT A

Attached to and incorporated in Gas Purchase Contract, dated January 1, 1972, between UNION OIL COMPANY OF CALIFORNIA, hereinafter referred to as "Union", and MARATHON OIL COMPANY (formerly The Ohio Oil Company), hereinafter referred to as "Marathon", both companies hereinafter referred to collectively as "Seller", and ALASKA PIPELINE COMPANY, hereinafter referred to as "Buyer".

GENERAL TERMS AND CONDITIONS

A. MEASURING STATION

1. Buyer shall install, maintain and operate, at Buyer's own expense, at or near the point of delivery, a measuring station properly equipped with orifice meters, flange connections, orifice plates and other necessary equipment by which the volume of gas delivered hereunder shall be measured, and Seller, to the extent that Seller has the right to do so, hereby, grants to Buyer the right to install, maintain and operate such equipment. Volumes shall be computed and orifice meters shall be installed, maintained and operated as prescribed by the American Gas Association in Gas Measurement Committee Report Number 3, including the appendix thereto, as published April, 1955, and any subsequent amendments, additions or changes thereto as may be made from time to time by the A.G.A. Gas Measurement Committee. Seller shall have access to such metering equipment at reasonable hours, but the reading, calibrating and adjusting thereof and the changing of charts shall be done only by Buyer.

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2. Seller shall install, maintain and operate, at its own expense such pressure regulators and check measuring equipment as it shall desire, so installed as not to interfere with the operation of Buyer's measuring equipment. Buyer shall have access to such check measuring equipment at reasonable hours, but the reading, calibrating and adjusting thereof and the

3. Each party shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment used in measuring deliveries hereunder. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its record and charts, together with calculations therefrom, for inspection and verification, subject to return within ten (10) days after receipt thereof.

4. In the event a meter is out of service, or registering inaccurately, the volume of gas delivered hereunder shall be estimated;

(a) By using the registration of any check meter or meters if installed and accurately registering, or in the absence of (a):

(b) By correcting the error if the percentage of error is ascertainable by calibration, test, or mathematical calculation or, in the absence of both (a) and (b), then:

(c) By estimating the quantity of delivery by deliveries during periods under similar conditions when the meter was registering accurately. AGO 570412

5. At least once each month Buyer shall verify the accuracy of Buyer's measuring equipment and Seller shall verify the accuracy of its check measuring equipment. If either party shall notify the other that it desires a special test of any measuring equipment, the parties shall cooperate to secure a prompt verification of the accuracy of such equipment. If either party at any time observes a variation between the delivery meter and the check meter, it will promptly notify the other party thereof and both parties will then cooperate to secure an immediate verification of the accuracy of such equipment. Each party shall give to the other notice of the time of all tests of meters reasonably in advance of the holding of such tests in order that the other

6. If, upon test, any measuring equipment is found to be in error not more than two per cent (2%), previous records of such equipment shall be considered accurate in computing deliveries hereunder; but such equipment shall be adjusted at once to record correctly. If, upon test, any measuring equipment shall be found to be inaccurate by an amount exceeding two per cent (2%), at a recording corresponding to the average hourly rate of flow for the period since the last preceding test, then any previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon, but in case the period is not known definitely or agreed upon such correction shall be for a period extending over one-half of the time elapsed since the date of last test, not exceeding a correction period of sixteen (16) days.

7. Each party shall preserve for a period of at least two (2) years all test data, charts and other similar records.

B. MEASUREMENTS

1. The sales unit of the gas deliverable hereunder shall be one (1) MCF of gas.

2. The volume of the gas delivered hereunder shall be determined as follows:

(a) The unit of volume for the purpose of measurement shall be one cubic foot of gas at a base temperature of sixty (60) degrees Fahrenheit and at a pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch absolute with correction for deviation from Boyle's Law. Computation of volumes shall be in accordance with applicable rules, regulations and orders promulgated by a recogni regulatory body.

(b) The average absolute atmospheric pressure shall be assumed to be fourt and seven-tenths (14.7) pounds to the square inch, irrespective of actual elevation

location of the point of delivery above sea level or variations in such atmospheric pressure from time to time.

(c) The deviation of the gas from Boyle's Law at the pressures, temperatures, and specific gravities under which the gas is delivered hereunder, shall be read from the A.G.A. convenient operating tables of "Supercompressibility Factors for Natural Gas", without adjustment of diluents, which have been developed from the basic tables contained in the A.G.A. Gas Measurement Committee Report No. 3.

(d) The temperature of the gas passing the meters shall be determined by the continuous use of a recording thermometer so installed by Buyer that it may properly record the temperature of the gas flowing through the meters. The arithmetical average of the hourly temperature readings recorded each twenty-four (24) hour day shall be used in computing gas volumes for that date.

(e) Unless the parties hereto agree to the use of a spot test method, the specific gravity of the gas delivered hereunder shall be determined by the continuous use of an Acme recording gravitometer, or other standard gravitometer agreed upon by the parties hereto, so installed that it may properly record the specific gravity of the gas flowing through the meters. The arithmetical average of the specific gravity recorded during each twenty-four (24) hour day shall be used in computing gas volume for that date. If the parties hereto agree to the use of a spot test method, such spot test shall be made with an Edwards type of gas balance, or by such other method as shall be agreed upon between the parties. If the spot test method is used, the specific gravity of the gas delivered hereunder shall be determined once monthly, or as much oftener as is found necessary in practice. The regular monthly test shall

natural gas delivered, until the end of such month or until changed by special test; the special test to be applicable from the day made through the remaining days in such month.

C. QUALITY OF GAS

1. Seller agrees that:

(a) The gas delivered hereunder shall have a total heating value of not less than nine hundred and fifty (950) British thermal units per cubic foot. If at any time Seller shall become unable to produce gas possessing at least such total heating value, Buyer shall have the option from time to time to refuse to accept th part of Seller's gas which is so deficient so long as said heating value remains belo nine hundred and fifty (950) British thermal units per cubic foot. In the event Buyer accepts delivery of said gas when the heating value thereof is below nine hundred and fifty (950) British thermal units per cubic foot, Buyer may reduce the total amount payable as the purchase price for gas delivered under this contract fo each month during which such deficiency obtains by an amount determined by multiplying such total amount by a fraction having as its numerator the average deficiency of British thermal units per cubic foot of gas below nine hundred and fifty (950) and its denominator nine hundred and fifty (950).

(b) Buyer shall have the right to determine, at such time or times as it may desire, the total heating value of the gas in British thermal units per cubic fo by means of some approved method of general use in the industry. Buyer shall giv to Seller notice of the time of all tests for determining the British thermal unit content of the gas to be conducted by such party reasonably in advance of making

the test in order that the other party may conveniently have its representative present. Should there be any material variance between tests by Buyer and Seller, a joint test will be run and will be controlling, effective from the first day of the calendar month preceding such joint test. The British thermal unit content per cubic foot shall be determined for a cubic foot of gas at a temperature of sixty degrees (60°) Fahrenheit when saturated with water vapor and at an absolute pressure equivalent to thirty inches (30") of mercury at thirty-two degrees (32°) Fahrenheit when the products of combustion are cooled to the initial temperature of gas and air and when the water formed by combustion is condensed to the liquid state.

2. Seller agrees that the gas delivered hereunder:

(a) Shall not contain more than one (1) grain of hydrogen sulphide per one hundred (100) cubic feet of gas as determined by the Tutwiler test or some other quantitative test, mutually agreeable to the parties hereto, after the presence of hydrogen sulphide has been indicated by qualitative test.

(b) Shall not contain more than twenty (20) grains of total sulphur per one hundred (100) cubic feet of gas.

(c) Shall not contain in excess of:

(i) Three per cent (3%) by volume of carbon dioxide;

(ii) One per cent (1%) by volume of Oxygen.

(d) Shall have a temperature of not more than one hundred twenty degrees (120°) Fahrenheit.

(e) Shall not contain more than four (4) pounds of water per one million (1,000,000) cubic feet of gas.

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3. In addition to meeting the above specifications, the gas delivered hereunder shall be commercially free from dust, gums, gum forming constituents, or other liquid or solid

matter which might become separated from the gas in the course of transportation through pipelines.

4. In the event Buyer shall exercise its option to refuse to accept that part of Seller's gas not meeting any of the above quality specifications, Seller shall be free to sell such rejected gas to others.

D. STATEMENTS AND PAYMENTS

1. On or before the fifteenth (15th) day of each calendar month after deliveries of gas are commenced hereunder, Buyer shall render a statement to Seller showing the amount of gas delivered hereunder during the last preceding calendar month. Buyer agrees to make payment to Seller on or before the twenty-fifth (25th) day of each calendar month for all gas delivered or for which any payment is due hereunder for the preceding month.

2. Each party shall have the right at reasonable times to examine the books, records and charts of the other party to the extent necessary to verify the accuracy of any statement, charge or computation made pursuant to the provisions of any Article hereof. If any such examination reveals any inaccuracy in such billing theretofore made, the necessary adjustment in such billing and payments shall be promptly made; provided that no adjustment for any billing or payment shall be made after the lapse of one (1) year from the rendition there

E. FORCE MAJEURE

AGO 570417

1. In the event of either party hereto being rendered unable, wholly or in part, by force majeure to carry out its obligations under this Agreement, other than to make payments theretofore accrued hereunder, it is agreed that on such party giving notice and full particulars such force majeure in writing or by telegraph to the other party as soon as possible after the

[illegible] giving such notice, so far

they are affected by such force majeure, shall be suspended during the continuance of any inability so caused but for no longer period, and such cause shall as far as possible be remedie with all reasonable dispatch. The term "force majeure" as employed herein means an occurrence not within the control of the party claiming force majeure and which by the exercise of due diligence such party is unable to prevent or overcome, and, subject to the exercise of due diligence to prevent or overcome, such occurrence shall include acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests, and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, the necessity for making repairs to or alterations of machinery or lines of pipe, freezing of wells or lines of pipe, partial or entire failure of wells or sources of supply of gas, any act or omission by parties not controlled by the party having the difficulty, any act or omission (including failure to take gas) of a purchaser of gas from Buyer which is excused by any event or occurrence of the character herein defined as constituting force majeure, and any other causes, whether of the kind herein enumerated or otherwise, not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome; such term shall likewise include (a) in those instances where either party hereto is required to obt servitudes, rights of way grants, permits or licenses to enable such party to fulfill its obligati hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such servitudes rights of way grants, permits or licenses, and (b) in those instances where either party hereto required to furnish materials and supplies for the purpose of constructing or maintaining facilities or is required to secure permits or permission from any governmental agency to enal

such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such materials and supplies, permits and permissions. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty, and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of opposing party when such course is inadvisable in the discretion of the party having the difficulty.

F. WARRANTY OF TITLE

Seller hereby warrants the title to all gas delivered by Seller to Buyer under this Agreement, the right to sell the same and that it is free from all liens and adverse claims, and agrees, if notified thereof by Buyer, to indemnify Buyer against all suits, actions, debts, accounts, damages, costs, losses, and expenses arising from or out of any adverse legal claims of any and all persons to or against said gas. Seller agrees to pay or cause to be paid all taxes and assessments levied on the gas prior to its delivery to Buyer (subject to reimbursement as provided in Article VII of this Gas Purchase Contract), and to pay or cause to be paid to the parties entitled thereto all royalties, overriding royalties or like charges against said gas or the value thereof. In the event any adverse claim of any character whatsoever is asserted in respect to any of said gas, Buyer may retain the purchase price thereof up to the amount of such claim without interest until such claim has been finally determined, as security for the performance of Seller's obligations with respect to such claim under this Section F, or until Seller shall have furnished bond to Buyer, in an amount and with sureties satisfactory to Buyer, conditioned for the protection of Buyer with respect to such claim.

G. REGULATORY BODIES

This Agreement is subject to all present and future valid orders, rules, and regulations of any regulatory body having jurisdiction. In the event any provision of this Agreement shall violate any applicable Federal or State law or valid applicable rule or regulation of Federal or State regulatory bodies having jurisdiction, then such provision shall be of no force and effect so long, and only so long, as it is in violation thereof, but the remainder of the agreement shall be valid and effective as though such provision or provisions had not been included herein..

H. OPERATION OF PROPERTIES

Seller shall have agents or employees available at all times to receive Buyer's dispatchers' requests for changes in rates of delivery of gas hereunder as required by Buyer from time to time.

EXHIBIT B

UNSURVEYED LANDS:

PARCEL 1: Beginning at the northeast corner of surveyed Section 1, Township 4 North, Range 12 West, S.M. Alaska; thence South 1.5 miles; thence East 1.0 mile; thence North 1.5 miles; thence West 1.0 mile to the point of beginning; which when surveyed will probably be:

TOWNSHIP 4 NORTH, RANGE 11 WEST, S.M.:

Section 6: All
Section 7: North 1/2 - (960 acres; more or less)

The above described parcel of land being covered by that certain United States Oil and Gas Lease issued effective 10/1/58 and bearing serial register number A-028142, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.

SURVEYED LANDS:

PARCEL 2: TOWNSHIP 4 NORTH, RANGE 12 WEST, S.M.:

Section 1: Lots 1, 2, 4, 5, and E 1/2 E 1/2 - (249.20 acres)

Section 12: North 1/2 - (134.40 acres)

The above described parcel of land being covered by certain United States Oil and Gas Lease issued effective 11/1/58 and bearing serial register number A-028143, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367 dated 5/1/59.

PARCEL 3: (a) TOWNSHIP 5 NORTH, RANGE 11 WEST, S.M.:

Section 29: West 1/2 - (320.00 acres)
Section 30: Lots 5, 6, 7, 8, 9, 11, 12, 13, 14, 15 - and E 1/2 - (372.23 acres)

The above described parcel of land being covered by that certain United States Oil and Gas Lease issued effective 10/1/55 and bearing serial register number A-028056, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.

(b) TOWNSHIP 5 NORTH, RANGE 11 WEST, S.M.:
Section 30: Lots 3 and 10 - (26.71 acres)

The above described parcel of land being covered in fee Oil and Gas Lease by and between Union Oil Company of California, as Lessee, and L. B. Edelman, et ux, as Lessor, dated 2/28/59, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.

(c) TOWNSHIP 5 NORTH, RANGE 11 WEST, S.M.:
Section 30: Lot 16 - (5.09 acres)

The above described parcel of land being covered by fee Oil and Gas Lease by and between Union Oil Company of California, as Lessee, and C. E. Johnson, as Lessor, dated 3/21/59, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.

PARCEL 4: (a) TOWNSHIP 5 NORTH, RANGE 11 WEST, S.M.:
Section 31: Lots 3, 4, 5, 7, 8, 10, and E 1/2 - (404.72 acres)

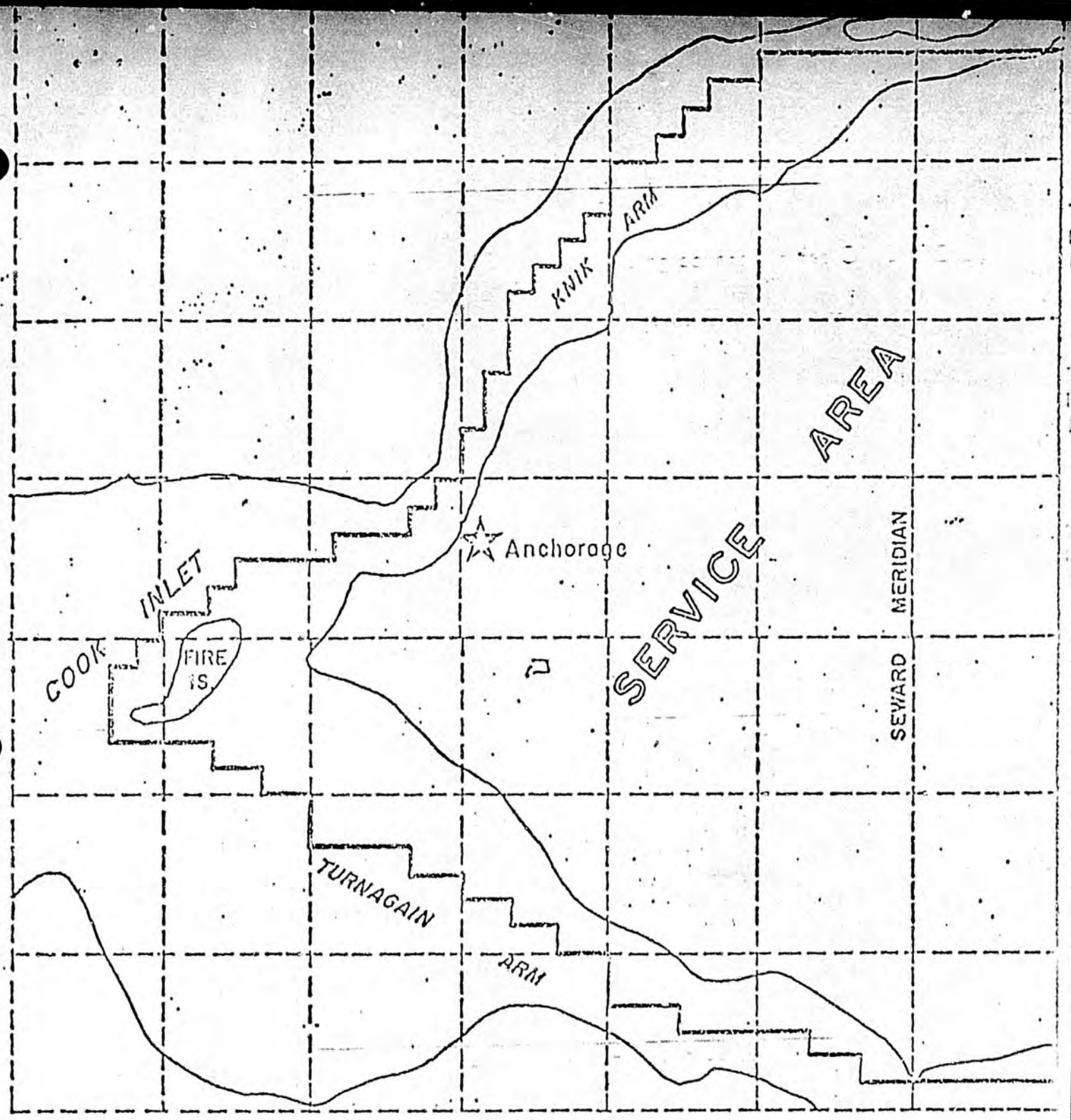
Section 32: West 1/2 - (320.00 acres)

The above described parcel of land being covered by that certain United States Oil and Gas Lease issued effective 10/1/55 bearing serial register number A-028055, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.

(b) TOWNSHIP 5 NORTH, RANGE 11 WEST, S.M.:
Section 31: Lot 6 - All - (5.19 acres)

The above described parcel of land being covered by fee Oil and Gas Lease by and between Union Oil Company of California, as Lessee, and R. L. Schmidt, as Lessor, dated 3/20/59, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.

and containing in the aggregate, 2,797.54 acres, more or less.



SERVICE AREA

BOUNDARIES OF "SERVICE AREA"

Referred to in Amendment of Gas Purchase Contract dated January 1, 1972 to, and thereby added to and made a part of, Gas Purchase Contract dated May 23, 1960 between

UNION OIL COMPANY OF CALIFORNIA, and
MARATHON OIL COMPANY (formerly THE OHIO OIL COMPANY)
"Seller"
and
ALASKA PIPELINE COMPANY
"Buyer"

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EXHIBIT

EXHIBIT C-1

Attached to Amendment to Gas Purchase Contract dated January 1, 1972., and thereby added to and made a part of Gas Purchase Contract dated May 13, 1960, between UNION OIL COMPANY OF CALIFORNIA and MARATHON OIL COMPANY (formerly THE OHIO OIL COMPANY), "Seller", and ALASKA PIPELINE COMPANY, "Buyer".

DESCRIPTION OF SERVICE AREA

The limits or boundaries of the "Service Area" are more particularly described from a point of beginning at the Southeast Corner of projected Section 25, T10N, R1E in the east Range Line of said Township, a point about in the middle of Turnagain Arm, and running along projected Section lines generally west-northwesterly through about the middle of Turnagain Arm to the Southwest Corner of projected Section 23, T12N, R6W, thence north to the Northwest Corner of projected Section 11, T12N, R6W, thence along projected Section lines generally northeasterly through about the middle of Knik Arm to the Northeast Corner of projected Section 13, T16N, R1E in the east Range Line of said Township, thence south along said Range Line to the point of beginning. The area encompassed within the above boundaries constitutes the "Service Area" and is comprised of surveyed and projected sections as follows:

T10N - R1E	Sections 1-30
T10N - R1W	Sections 1-18, 21-26
T10N - R2W	Sections 1-15
T11N - R1E	All Sections
T11N - R1W	All Sections
T11N - R2W	All Sections
T11N - R3W	Sections 1-28, 35-36
T11N - R4W	Sections 1-14

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T12N - R1E	All Sections
T12N - R1W	All Sections
T12N - R2W	All Sections
T12N - R3W	All Sections
T12N - R4W	All Sections
T12N - R5W	Sections 1-28, 35-36
T12N - R6W	Sections 1, 11-14, 23-24
T13N - R1E	All Sections
T13N - R1W	All Sections
T13N - R2W	All Sections
T13N - R3W	All Sections
T13N - R4W	Sections 1, 11-17, 19-36
T13N - R5W	Sections 22-28, 31-36
T14N - R1E	All Sections
T14N - R1W	All Sections
T14N - R2W	All Sections
T14N - R3W	Sections 1-4, 9-17, 20-36
T15N - R1E	All Sections
T15N - R1W	All Sections
T15N - R2W	All Sections
T15N - R3W	Sections 13, 23-27, 33-36
T16N - R1E	Sections 13-36
T16N - R1W	Sections 13-36
T16N - R2W	Sections 23-27, 33-36

The Section Numbers given above are inclusive in denoting those Sections lying within the "Service Area" boundaries.

All Townships and Ranges noted in the above description and notation are those from the Seward Base Meridian, State of Alaska.

Union Oil and Gas Division: Western Region
Union Oil Company of California
909 W. 9th Avenue, Anchorage, Alaska 99501
Telephone: (907) 279-7681

1/1/75 Amend-ment

UNION

Robert T. Anderson
District Land Manager

January 29, 1975

Alaska Public Utilities Commission
1100 McKay Building
338 Denali Street
Anchorage, Alaska 99501

Director
Division of Lands
323 East Fourth Avenue
Anchorage, Alaska 99501

Supervisor
U.S.G.S.
Oil and Gas Operations
P. O. Box 259
Anchorage, Alaska 99501

RE: AMENDMENTS TO GAS PURCHASE AGREEMENTS

Gentlemen:

Enclosed for your records are copies of the following Amendments to Gas Purchase Agreements.

1. Amendment to Gas Purchase Agreement for Sterling Unit Area dated September 17, 1962.

2. Agreement to Amend and modify Gas Purchase Agreement Sterling Unit Area, dated November 1, 1973.

3. Amendment of Gas Purchase Contract Kenai Unit, Kenai Gas Field Contract effective date, January 1, 1975.

RECEIVED
A.P.U.C.
JAN 31 9 24 AM '75

Very truly yours,

Robert T. Anderson

nr
enclosures

AGO 570426

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

January 23, 1975

Alaska Public Utilities Commission
1100 MacKay Building
338 Denali Street
Anchorage, Alaska 99501

Gentlemen:

The enclosed letter agreement with our suppliers at the Kenai gas field should be filed and become part of the contract amendment which we filed with you last week. It substantiates the final arrangements we made last month with the suppliers in connection with the amended contract.

Very truly yours,

Dale Teel
President

DT:lv
Enclosure

RECEIVED
A.P.U.C.
JAN 27 10 03 AM '75

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Union Oil Company of California
Union Oil Center, Box 7600, Los Angeles, California 90051
Telephone (213) 486-7055

UNION 76

W. L. Bradford
Regional Gas Manager

December 17, 1974

Alaska Pipeline Company
P. O. Box 6288
Anchorage, AK 99501

ATTN: Mr. Dale Teel

Gentlemen:

Reference is made to that certain Amendment of Gas Purchase Contract (the "Amendment") to be effective the 1st day of January, 1975. We have mutually agreed to certain additional considerations described below. Now therefore Union Oil Company of California (Union) and Marathon Oil Company (Marathon), both companies hereinafter collectively called "Seller" and Alaska Pipeline Company hereinafter called "Buyer" agree as follows:

1. "Special Delivery Capacity" and "Special Deliverability Charge" as set forth in the Amendment are modified to provide (a) Seller shall provide and maintain Special Delivery Capacity during the period commencing July 1, 1975 and ending December 31, 1975, of not less than 140,000 MCF per day and during the period commencing January 1, 1976 and ending December 31, 1985, of not less than 160,000 MCF per day; and (b) the Special Deliverability Charge as set forth in Section 3.1 of the Amendment is suspended until July 1, 1975. On July 1, 1975, said Special Deliverability Charge as provided in said Amendment shall commence and continue for a period ending June 30, 1986.

2. If, during any one of the three (3) calendar years commencing January 1, 1975 and ending December 31, 1977, Alaska Pipeline Company loses significant volumes of gas sales used in

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2. (Continued)

the present contracts for generating wholesale electrical power then at Buyer's election and upon notification by Buyer setting forth full particulars, Union and Marathon shall at the end of any such calendar year release Alaska Pipeline Company from its Take or Pay obligation under the Amendment for a volume of gas equivalent to the wholesale electrical power volume loss sustained by Alaska Pipeline Company (less any gas purchased from other than Seller); but such release shall not exceed a total volume of 6.5 billion CF of gas (less any gas purchased from other than Seller) in any one such year. Concurrent with the release of Take or Pay obligation described above, "Seller's Gas Reserves" as set forth in the Amendment shall likewise be reduced by an equal volume.

If you agree to the foregoing, please so indicate by your signature in the space provided hereunder.

Very truly yours,

UNION OIL COMPANY OF CALIFORNIA

By _____
Its Attorney-in-fact

MARATHON OIL COMPANY

By _____
Senior Vice President

SELLER

AGREED December 18, 1974

ALASKA PIPELINE COMPANY

By _____

BUYER

Rule Tech copy

AMENDMENT OF GAS PURCHASE CONTRACT

THIS AGREEMENT, made and entered into effective as of the 1st day of January, 1975, by and between UNION OIL COMPANY OF CALIFORNIA, hereinafter sometimes referred to as "Union," and MARATHON OIL COMPANY (formerly The Ohio Oil Company), hereinafter sometimes referred to as "Marathon," both companies hereinafter referred to collectively as "Seller" and sometimes herein individually as "seller" and ALASKA PIPELINE COMPANY, hereinafter referred to as "Buyer,"

W I T N E S S E T H :

WHEREAS, Buyer and Seller are parties to that certain Gas Purchase Contract dated May 13, 1960, as amended and modified, covering the purchase and sale of natural gas from certain properties of Union and Marathon located on the Kenai Peninsula, Alaska; and

WHEREAS, the parties desire to further amend said Gas Purchase Contract, as heretofore amended and modified, as of the effective date, stated above;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements herein contained, the parties hereby amend that certain Gas Purchase Contract between Buyer and Seller dated May 13, 1960, as heretofore amended and modified, and agree as follows:

1. Each and every prior amendment to, or modification of that certain Gas Purchase Contract dated May 13, 1960, including specifically but without limitation the Amendment of Gas Purchase Contract dated effective January 1, 1972, (the "January 1, 1972 Amendment") which has been

entered into or agreed to by any party hereto, and Exhibits "A", "B", "C" and "C-1" of said January 1, 1972 Amendment, are hereby cancelled and shall be of no further force or effect as of the effective date of this Amendment.

2. Exhibits "A", "B" and "C", attached hereto, are hereby added to and made a part of said Gas Purchase Contract dated May 13, 1960.

3. Commencing with the word "WITNESSETH", on the first page of said Gas Purchase Contract dated May 13, 1960, and including Pages 1 through 15 thereof, said contract is hereby amended to read as follows:

WHEREAS, Alaska Gas and Service Company, a Division of Alaska Interstate Company (formerly named Anchorage Natural Gas Corporation), hereinafter sometimes referred to as "Anchorage," has held and now holds, along with other such Certificates, a Certificate from the Alaska Public Utilities Commission, to distribute gas for domestic, commercial and industrial purposes within the State of Alaska; and

WHEREAS, Buyer owns and operates a gas transmission pipe line system extending from the Kenai Unit Area, Third Judicial Division, State of Alaska, to the City of Anchorage; and

WHEREAS, Buyer and Anchorage have entered into an agreement under which Buyer has agreed to sell, deliver and furnish to Anchorage and Anchorage has agreed to purchase, take and receive from Buyer, Anchorage's requirements for gas pursuant to the terms thereof and of this Agreement; and

WHEREAS, Union and Marathon each own or control oil, gas and mineral leaseholds and/or lands within the Kenai Unit Area, which leaseholds and lands are more particularly described in Exhibit "B" attached

hereto and made a part hereof, and each has a supply of gas by virtue of its ownership or control of said leaseholds and lands which, together with certain other gas that Union and/or Marathon may from time to time purchase from co-owners of interests in said leaseholds and lands and volumes of gas from any other source or sources which Union and/or Marathon may elect from time to time to substitute for gas from said leaseholds and lands which it is willing to sell to Buyer within the total volume limitation hereinafter provided; and

WHEREAS, Buyer desires to purchase from Seller gas for its requirements;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements herein contained, the parties hereto do hereby covenant and agree as follows:

I
DEFINITIONS

Except where the context otherwise indicates another or different meaning or intent, the following terms are intended and used herein and in Exhibit "A", attached hereto and made a part hereof, and shall be construed to have meanings as follows:

1.1 The term "day" shall mean a period of twenty-four (24) consecutive hours beginning and ending at eight o'clock a.m., Alaska Standard Time.

1.2 The term "month" Shall mean a period beginning at eight o'clock a.m. on the first (1st) day of a calendar month and ending at eight o'clock a.m. on the first (1st) day of the next succeeding calendar month.

1.3 The term "year" shall mean a period of twelve (12) consecuteve months.

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1.4 The term "calendar year" shall mean a period of twelve (12) consecutive months beginning on the first day of January of any calendar year.

1.5 The term "gas" shall mean natural gas meeting the standards set forth in Section C of Exhibit "A" hereof.

1.6 The term "Mcf" shall mean one thousand (1,000) cubic feet.

1.7 The term "British thermal unit" (Btu) is defined as the amount of heat required to raise the temperature of one (1) pound of water from fifty-nine degrees (59°) Fahrenheit to sixty degrees (60°) Fahrenheit at a pressure of fourteen and sixty-five one hundredths (14.65) pounds per square inch absolute.

1.8 The term "Seller's Delivery Capacity" shall mean the quantity of gas which can be withdrawn (subject to any applicable State or Federal statutes and any valid rules, orders and regulations of any State or Federal regulatory body) and which shall be available for delivery to Buyer daily under this agreement in the quantities set forth in Article II and Section 3.6 hereof at the point or points of delivery described in Article V at the pressure provided for in Article VI hereof.

1.9 The term "Special Delivery Capacity" shall mean the increased delivery capacity (subject to any applicable State or Federal statutes and any valid rules, orders and regulations of any State or Federal regulatory body) that Seller is obligated to deliver to Buyer pursuant to Section 3.1 hereof.

1.10 The term "Price" shall mean the price to be paid by Buyer for gas delivered to Buyer hereunder as provided for in Section 7.1 hereof.

1.11 The term "Special Deliverability Charge" shall mean the additional compensation Seller is to receive pursuant to Section 3.1 hereof for providing increased deliverability and in addition to the gas price as provided for in Section 7.1 hereof.

1.12 The "Kenai Unit Area" as used herein means that area described in Unit Agreement for the Development and Operation of the Kenai Unit Area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated May 1, 1959, and revisions thereto.

1.13 The term "Annual Contract Quantity" shall mean the applicable Daily Contract Quantity as defined in Section 2.4 hereof multiplied by the number of days in the year.

1.14 The term "Seller's Gas Reserve" shall mean the same as defined in Section 2.1 hereof.

1.15 The "Natural Term" shall mean the duration of the period in which the Gas Purchase Contract shall remain in full force and effect as provided for in Section 8.1(a) hereof.

1.16 The "Extended Term" shall mean the same as set forth in Section 8.1(b).

II
SCOPE OF AGREEMENT AND QUANTITY OF GAS COVERED BY CONTRACT

2.1 Subject to and in accordance with all of the terms, conditions and limitations set forth hereinafter and in Exhibit "A" hereof, Buyer agrees to purchase and receive from Seller, and Seller agrees to sell and deliver or cause to be delivered to Buyer, the following quantities of gas:

(a) For the period January 1, 1972 through December 31, 1974, the quantity of gas delivered by Seller to Buyer under that certain Amendment of Gas Purchase Contract dated January 1, 1972; and

(b) For the period commencing January 1, 1975 and ending at the time specified in Section 8.1 hereof, such quantity as Buyer may elect to purchase;

provided, however, that the sum of all such quantities shall not exceed a maximum total quantity of five hundred fifty billion (550,000,000,000) cubic feet of gas. Said maximum total quantity of gas is hereinafter referred to as "Seller's Gas Reserve" and, except as hereinafter provided, shall be produced solely from the leaseholds and/or lands described in Exhibit B. Seller shall have the right, but not the obligation, to deliver to Buyer, in substitution for a portion of the gas constituting Seller's Gas Reserve, volumes of gas (called Substitute Gas) produced from sources other than Exhibit B leaseholds and/or lands by Seller hereunder, but the delivery of such Substitute Gas shall not (a) enlarge the maximum quantity of gas referred to above, or (b) confer upon Buyer any right to require delivery of gas from any source except Exhibit B leaseholds and/or lands. Should Seller deliver to Buyer volumes of Substitute Gas, the volumes so tendered shall be deemed deliveries of gas hereunder for all purposes. Seller's Gas Reserve shall be reduced whenever and to the extent that any Lessor within the Kenai Unit Area shall exercise partially or wholly any right to take its share of royalty gas in kind for delivery either directly or indirectly to Buyer and/or its affiliates. In such event, the Special Delivery Capacity shall also be reduced as provided in Section 3.4, 3.5 and 3.6 hereof.

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Said Exhibit B leaseholds and/or lands shall constitute the leaseholds and/or lands covered by, or subject to, this Agreement for all purposes, including Article IV (Reservations of Seller).

2.2 Seller shall, with due diligence, operate the lands and leaseholds subject to this Agreement in a skillful and reasonably prudent manner to the end that Seller's Delivery Capacity, Special Delivery Capacity and Seller's Gas Reserve shall be maintained during the Natural Term hereof at the volume required hereunder from time to time. Seller shall, upon written request from Buyer to be made not more frequently than one time per year, certify to Buyer that the gas remaining to be delivered hereunder is available from the leaseholds and/or lands described in Exhibit "B", and that said quantity of gas is free of commitments to others. Seller shall furnish to Buyer with such certificate a report of an Independent Geologist substantiating such certification, which Independent Geologist (employed for the purpose of rendering such report) shall be one designated by Seller.

2.3 Buyer agrees that, commencing January 1, 1975 and continuing thereafter for so long as this Agreement is in effect, and subject to all the terms and provisions of this Agreement, but without limitation upon Buyer's right to purchase greater quantities of gas hereunder, to either purchase and pay for or to pay for, if available, whether taken or not, each calendar year during the remaining Natural Term of this Agreement the Annual Contract Quantity.

2.4 The "Daily Contract Quantity" shall be 72,000 Mcf per day for the period commencing January 1, 1975 and ending December 31, 1985. Thereafter, but ending at the time specified in Section 8.1, hereof, the

Daily Contract Quantity shall be the lesser of 72,000 Mcf per day or 75% of Seller's Delivery Capacity established pursuant to Section 3.6 hereof.

2.5 If Buyer shall fail in any calendar year during the Natural Term hereof commencing with the year beginning January 1, 1975 to take the Annual Contract Quantity, then Seller shall, within sixty (60) days after the end of such year, render a bill to Buyer for the amount of the deficiency based upon the price in effect hereunder as of the last day of the calendar year in which such deficiency occurred. There shall be deducted from such deficiency those volumes of gas which Seller failed to deliver in accordance with the terms hereof on any day or days and those volumes of gas which Buyer was unable to take on any day or days by reason of "force majeure" during such deficiency year. Buyer agrees, notwithstanding that a part of such deficiency may be in good faith dispute, to make payment to Seller for the full amount of such bill within fifteen (15) days after receipt of such bill. If all or any part of the deficiency is in good faith dispute, then the amount of such deficiency in good faith dispute shall, when received by Seller from Buyer, be placed by Seller in an interest bearing account until such good faith dispute is settled. When any such settlement is made either in part or in whole in favor of Buyer, then, Seller shall within fifteen (15) days thereafter make payment to Buyer for the amount plus interest accrued to date thereon for that part of such deficiency so settled in favor of Buyer. The amount plus interest to date thereon for any settlement made in part or in whole in favor of Seller shall be for the account of Seller.

2.6 If Buyer makes payments to Seller pursuant to Section 2.5

hereof for gas not taken during any calendar year of the Natural Term hereof commencing with the year beginning January 1, 1975, Buyer shall have the right during any succeeding calendar year or years during the remaining Natural Term as provided for in Section 8.1(a) of this Agreement to deduct such sums from payments otherwise due Seller for quantities of gas purchased by Buyer pursuant to Section 2.3 hereunder in excess of the Annual Contract Quantity.

2.7 Notwithstanding the provisions of Sections 2.5 and 2.6 hereof to the contrary if during the last two calendar years of the Natural Term of this Agreement Buyer fails to take the Annual Contract Quantity then Seller shall have the option as follows:

(a) to render a bill to Buyer for such deficiency, as provided for in Section 2.5 of this Agreement, in which event Buyer shall have the right during the next succeeding two calendar years to take the gas so paid for and not taken without further payment, provided, that Seller may subsequently at any time after December 31, 1992 reimburse Buyer for any unrecovered deficiency amounts paid for pursuant to this Section 2.7(a) hereof and thereafter no further claim shall be made by either party hereto for such a deficiency and this Agreement shall terminate; or

(b) to notify Buyer that Seller has chosen to forego payment for such deficiency and thereafter no further claim shall be made by parties hereto for such deficiency and this Agreement shall terminate.

The Extended Term of this Agreement shall apply only for the recoupment

of gas if Seller exercises its option rights pursuant to Section 2.7 hereof for gas paid for but not taken by Buyer for the Calendar Years 1991 and 1992. If there are gas deficiencies for calendar years prior to 1991, then, Buyer is only allowed to recoup the gas during the Natural Term hereof.

2.8 Buyer reserves the right to contract with others for the purchase of sufficient gas to meet any quantities of gas needed or desired by Buyer anywhere on its system provided that Buyer meets its purchase obligations hereunder.

III
SPECIAL DELIVERY CAPACITY, SPECIAL DELIVERABILITY CHARGE AND SELLER'S DELIVERY CAPACITY

3.1 Seller agrees to provide and maintain during the period commencing January 1, 1975 and ending December 31, 1975 a Special Delivery Capacity of not less than 140,000 Mcf per day. Seller further agrees to provide and maintain during the period commencing January 1, 1976 and ending December 31, 1985, a Special Delivery Capacity of not less than 160,000 Mcf per day. Said Special Delivery Capacity shall be subject to Section 3.4 hereof. As consideration for providing and maintaining said Special Delivery Capacity, during the period commencing January 1, 1975 and ending December 31, 1985, Buyer agrees to pay Seller monthly the sum of nineteen and one-half (19-1/2) cents per Mcf for all gas taken or to be paid for whether taken or not (hereinafter called Special Deliverability Charge) in accordance with the procedures set forth in Section D of Exhibit "A" hereto. Said Special Deliverability Charge shall be in addition to the price otherwise payable under Article VII hereof.

3.2 Such Special Deliverability Charge shall be subject to adjustment effective on January 1, 1976 and on January 1 of each year thereafter during the term provided for in Section 8.1 hereof at which times Seller shall receive the greater of:

(a) The Special Deliverability Charge without adjustment as provided for in Section 3.1 herein (19-1/2¢ per Mcf) or

(b) The adjusted Special Deliverability Charge determined as follows:

$$\text{Special Deliverability Charge without adjustment} \times \frac{\text{Chosen Index for the November immediately preceding the year for which charge is being adjusted}}{\text{Chosen Index for November 1974}}$$

The term "Chosen Index" shall mean the Wholesale Price Index for all commodities, not seasonally adjusted, (Base: 1967 = 100) as published monthly by the U. S. Department of Labor, Bureau of Labor Statistics. If the "Base Year" of the "Chosen Index" is changed to a year other than 1967 = 100, the new index will be rebased to 1967 = 100 using the appropriate "rebasing factor" as published by the U. S. Department of Labor, Bureau of Labor Statistics, before the adjustment calculations are performed. The use of this rebasing factor will have no effect on year-to-year percent changes.

3.3 Notwithstanding any other provisions hereof, if during the period commencing January 1, 1975 and ending December 31, 1985, Seller fails for any reason, except a reason constituting "force majeure"

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under Exhibit "A" hereof, to have available for delivery to Buyer the volume requested by Buyer, up to 100% of the applicable Special Delivery Capacity, then the Special Deliverability Charge shall not apply to the gas taken during the period or periods of such deliverability deficiency; provided, however, whenever, on any day Buyer shall request increased volumes over those that it is receiving at the time of such request, Seller shall have a reasonable period within which to diligently adjust well flow rates and mechanical operations as may be necessary to provide the additional volumes and during such period said Special Deliverability Charge shall continue to be applicable.

3.4 Seller's Special Delivery Capacity set forth in Section 3.1 shall be reduced whenever and to the extent any of the respective Lessors of the oil and gas leases subject to this Agreement elects to take its royalty in kind from the Kenai Unit Area for delivery either directly or indirectly to Buyer and/or its affiliates. Such reduction shall be equal to the volume of such gas being taken in kind as royalty and so delivered to Buyer.

3.5 For Buyer's use as a forecast only, on or before January 1, 1984 Seller shall provide Buyer with a single forecast which shall contain a schedule of Seller's estimate of Seller's Delivery Capacity for each year hereunder from and after December 31, 1985, for the remainder of the Natural Term hereof.

3.6 For the purpose of establishing the Daily Contract Quantity

applicable from time to time from and after December 31, 1985 pursuant to the provisions of Section 2.4, Seller shall on or before July 1, 1985 and each July 1 of the remainder of the Natural Term hereof notify Buyer of Seller's Delivery Capacity that Seller undertakes to maintain for the twelve (12) months commencing on the following January 1; provided, however, the Seller's Delivery Capacity shall never be less than 133% of that quantity obtained from dividing Seller's Gas Reserve less the cumulative volume of gas previously paid for by Buyer, whether taken or not, by the number of days remaining in the Natural Term hereof. Said Delivery Capacity shall be reduced whenever and to the extent any of the respective Lessors of the oil and gas leases subject to this Agreement elect to take its royalty in kind from the Kenai Unit Area for delivery either directly or indirectly to Buyer and/or its affiliates. Such reduction shall be equal to the volume of such gas being taken in kind as royalty and so delivered to Buyer and/or its affiliates.

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IV
RESERVATIONS OF SELLER

Without impairment of Seller's Gas Reserve, except as provided in Section 2.1, Seller hereby expressly reserves the following rights with respect to gas in, or which may be produced from, the leaseholds and/or lands covered by this Agreement:

4.1 The right to use gas produced from said leaseholds and/or lands for the following purposes:

(a) For the development and operation of such leaseholds and/or lands owned by Seller and any other leaseholds and/or lands owned by Seller or in which Seller owns an interest located in the Kenai Unit Area.

(b) For delivery to the Lessors in Seller's leases of the gas which such Lessors are entitled to take in kind under the terms of such leases.

(c) For the operation of the facilities which Seller may install in order to deliver gas hereunder in accordance with the terms hereof.

(d) For domestic use by Seller's employees employed in conducting operations in said Unit Area.

(e) For all other uses of Seller, including existing or future commitments of gas by Seller to others for any purpose whatsoever.

4.2 Seller shall have the right at its option to extract, or cause to be extracted, liquefiable hydrocarbons from the gas delivered hereunder by means of processing in a plant to be located in the field or at any point along Buyer's transmission line; such right to process and

extract, as herein reserved to Seller, being conditioned as follows:

(a) Not more than one such plant shall be constructed on Buyer's pipeline.

(b) The residue gas, after processing, shall have a total heating value of not less than 950 Btu's per cubic foot.

(c) Seller shall reimburse Buyer for the actual fuel consumed in the processing operation, and for a calculated amount sufficient to cover shrinkage.

(d) Seller shall provide such compression as may be necessary to make up any pressure drop resulting from such processing in excess of 50 psig.

(e) Seller shall furnish and pay the cost of installing block valves and by-pass valves required to effect delivery of gas to such plant and redelivery to the Buyer after processing.

(f) Seller agrees to indemnify and save Buyer harmless from all losses, damages and expenses to third parties which may occur or be asserted by reason of accident or occurrences resulting from Seller's operations in processing the gas delivered through the processing facilities.

V
POINT OF DELIVERY

5.1 The delivery point for the gas deliverable hereunder shall be at the upstream flange of Buyer's master meter located in Section 30, Township 5 North, Range 11 West, Kenai Peninsula Borough, Seward Base and Meridian, Alaska, or at other delivery points as hereinafter provided in Section 5.4 hereof.

5.2 Title to and ownership of such gas shall pass to and absolutely vest in Buyer at the point of delivery as aforesaid.

5.3 As between the parties hereto, Seller shall be in control and possession of the gas deliverable hereunder and shall indemnify and hold Buyer harmless for any damage or injury caused thereby until the same shall have been delivered to Buyer, after which delivery, Buyer shall be deemed to be in exclusive control and possession thereof and shall indemnify and hold Seller harmless for any injury or damage caused thereby.

5.4 Seller may at its option, and upon reasonable notice to Buyer, deliver gas to Buyer hereunder at any point on Buyer's pipeline system (which, if exercised, shall become an additional delivery point hereunder), provided:

(a) Notwithstanding any provision to the contrary contained in this Agreement, such gas delivered at any such additional delivery point shall be at a pressure sufficient to enter Buyer's pipeline at that additional delivery point.

(b) Such gas delivered at any such additional delivery point shall not reduce, nor shall it impair Buyer's ability to utilize, Seller's Delivery Capacity or Special Delivery Capacity hereunder;

(c) All costs and expenses for connections and measurement shall be paid by Seller;

(d) All gas so delivered to any such additional delivery point shall meet all the quality specifications hereof, and

(e) The quantities of gas so delivered at any such additional delivery point shall be considered for all purposes gas delivered pursuant to this Agreement.

VI
PRESSURE

6.1 From January 1, 1975 through December 31, 1985 the gas to be delivered hereunder shall be delivered by Seller into Buyer's facilities at said point or points of delivery at a pressure of seven hundred (700) pounds per square inch gauge or at the pressure existing from time to time in Buyer's facilities at said point or points of delivery whichever is lower. Thereafter, during the term hereof such gas shall be delivered by Seller into said facilities at a pressure of five hundred (500) pounds per square inch gauge or at the pressure existing from time to time in said facilities whichever is the lower. Higher pressures may be required to comply with the provisions of Section 5.4 (a) for any gas delivered at Seller's option pursuant thereto.

VII
PRICE

7.1 Subject to the provisions of 7.2 below, the price to be paid by Buyer for gas delivered to Buyer hereunder shall be as follows:

January 1, 1975 through December 31, 1975	22.0¢ per Mcf
January 1, 1976 through December 31, 1980	24.0¢ per Mcf
January 1, 1981 through December 31, 1985	27.0¢ per Mcf

After December 31, 1985, the price for all gas delivered hereunder in any year thereafter shall not be less than the greater of (1) 27 cents per Mcf, or (2) the average price from gas sales in the Cook Inlet Area as shown on Exhibit C, attached hereto, and received by Seller in aggregate

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during the year commencing January 1, 1985 and ending December 31, 1985 from all new sales made to buyers other than Buyer after January 1, 1972, hereinafter called the "Average Third Party Price". For the purposes of clause (2) above the Average Third Party Price shall mean the aggregate proceeds on which royalty was calculated and paid from all such new sales to others during such year, divided by the total quantity of such gas so delivered; provided, however, the aggregate quantity of such deliveries and sales to others during the year commencing January 1, 1985 and ending December 31, 1985, shall be at least one-fourth (1/4) of the quantity of gas delivered to Buyer hereunder during such year.

7.2 In the event that any new, additional or increased taxes are imposed on and paid by Seller after May 13, 1960 with respect to the gas sold hereunder, Buyer shall reimburse Seller, as an integral part of the price of gas sold hereunder a sum sufficient to cover one hundred percent (100%) of any such new, additional or increased taxes so paid by Seller irrespective of the mode of imposition. As used herein, the term "new, additional or increased taxes" shall not include taxes in effect on May 13, 1960 up to the respective rates thereof on said date imposed on Seller with respect to the working and royalty interests in connection with the gas sold hereunder.

The term "tax as used herein shall mean (1) any tax (other than ad valorem, capital stock, general property, or income and excess profit taxes), or (2) similar charge now or hereafter levied, assessed or made by any governmental authority on the gas itself or on the act, right or privilege of production, severance, gathering, transportation, sale or delivery of gas which is measured by the volume, value or sales

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price to Buyer of the gas in question but shall not include any value attributable to the liquid hydrocarbons in said gas, that are removed by processing; provided, however, that the term "tax" shall not be deemed to include (1) any processing tax imposed on Seller because of the fact that gas may be processed or handled through or in any plant, or (2) any general franchise tax imposed on corporations on account of their corporate existence or on their right to do business within the state as a foreign corporation, or (3) any delinquent interest, penalty, or audit payments that may be attributable to any tax.

Taxes or assessments applicable to any royalty, overriding royalty, production payment, or similar interest shall be considered to be covered by the provisions hereof to the extent reimbursement made by Buyer to Seller with respect thereto is passed on by Seller to the owner of such royalty, overriding royalty, production payment, or similar interest.

The above notwithstanding, should Seller at any time pay ad valorem mineral rights property taxes attributable to gas which Buyer has the right to receive hereunder, Seller will notify Buyer in writing, stating the amount thereof, along with adequate supporting information, and Buyer will, within thirty (30) days after the receipt of such notice from Seller, reimburse Seller in the amount of such taxes. The reimbursement shall be based upon the ratio which the volume of gas Buyer has the right to receive hereunder as of the date of assessment bears to the total volume of gas reserves underlying the properties subject to this Agreement as of the assessment date or in the event the lands subject to this Agreement are not assessed separately but rather as part of other

lands, the reimbursement shall be based upon the ratio which the volume of gas Buyer has the right to receive hereunder as of the date of assessment bears to the total volume of gas reserves underlying all the lands so assessed. Unless the total gas underlying the properties is valued separately for assessment purposes, the amount of the ad valorem mineral rights property taxes assigned to the gas each year shall be that portion of the total tax that the value of the gas bears to the total value of all the liquids and gas combined as determined by the assessor before applying any depreciation charges, operating costs, or present worth factors. The intent of this paragraph is that the Buyer shall pay all ad valorem mineral rights property taxes reasonably attributable to gas which Buyer has the right to receive hereunder, and the amount of such taxes shall be determined in an equitable manner to produce that result. Nothing contained herein shall imply that Buyer has any title to any volume of gas it has the right to receive hereunder.

Failure of Seller to notify Buyer within six (6) months after the due date, of the payment by Seller of any ad valorem mineral rights property taxes on gas which Buyer has the right to receive hereunder shall constitute a waiver by Seller of the reimbursement by Buyer for that particular item, but shall not constitute a waiver of any rights to reimbursement for the payment of such tax for subsequent periods.

7.3 Seller agrees to pay or cause to be paid to the parties entitled thereto all royalties, overriding royalties or like charges against said gas or the value thereof. Buyer agrees to reimburse Seller for all "excess royalty payments" which Seller shall be required to pay to the State of Alaska, United States of America or other royalty owners

with respect to gas sold and delivered to Buyer hereunder. Such payments shall be made by Buyer to Seller within ten (10) days following receipt of statements from Seller therefor. The term "excess royalty payments" as used herein is defined as the amount by which actual royalty payments by Seller to the State of Alaska, United States of America, or other royalty owners under the respective oil and gas leases subject to this Agreement exceeds the amount such payment would have been if the royalty value thereunder had been calculated upon the sums received by Seller pursuant to this Agreement.

VIII
TERM

8.1 This Gas Purchase Contract shall from the effective date hereof continue and remain in full force and effect for:

(a) a Natural Term ending December 31, 1992; provided, however, in the event Seller has after January 1, 1972 and prior to December 31, 1992, sold and delivered to Buyer hereunder a maximum total quantity of gas equal to Seller's Gas Reserve as defined in Section 2.1 hereof, then this Agreement shall thereupon terminate or,

(b) at Seller's sole option, as provided for in Section 2.7 hereof, an Extended Term of not more than two (2) calendar years beyond the Natural Term hereof.

None of the covenants or agreements made in this Agreement shall survive the expiration of the term as set forth in Sections 8.1 (a) and 8.1 (b).

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IX
ADDRESSES

9.1 Until Buyer is otherwise notified in writing by Union, the address of Union is and shall remain as follows:

Union Oil Company of California
909 West Ninth Street
Anchorage, Alaska 99501

and, unless Buyer is otherwise notified in writing by Marathon, the address of Marathon is and shall remain as follows:

Marathon Oil Company
P. O. Box 2380
Anchorage, Alaska 99510

and, unless Seller is otherwise notified in writing by Buyer, the address of Buyer is and shall remain as follows:

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

All notices required to be given in writing hereunder shall be given to the respective parties at such addresses or such other addresses as the parties respectively shall designate by written notice, and all notices required herein to be given to Seller shall be give to both Union and Marathon.

X
MISCELLANEOUS

10.1 No waiver by either party hereto of any one or more defaults by the other in the performance of any provisions of this Agreement shall operate or be construed as a waiver of any future default or defaults, whether of a like or of a different character.

10.2 This Agreement shall be binding upon and inure to the benefit of the successors and assigns of the respective parties hereto, and shall

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constitute a covenant running with the lands and leasehold estates covered hereby. Seller and Buyer both agree that no sale or transfer of said properties of Seller or any part thereof or of all or substantially all of Buyer's said system shall be made unless the purchaser or transferee thereof shall assume and agree to be bound by this Agreement insofar as the same shall effect and relate to the property or interest sold or conveyed. It is agreed, however, that nothing contained in this paragraph shall in any way prevent either party hereto from pledging or mortgaging its rights hereunder for security of its indebtedness.

10.3 Each of the parties hereto agrees to proceed with diligence in a good faith effort to obtain and maintain in good standing such governmental authorization, certificates and franchises as may be necessary to enable it to perform its other obligations under this Agreement.

10.4 Seller grants to Buyer, so far as Seller has the right to do so, right-of-way on the leases and lands covered by this Agreement for Buyer's gathering pipe line and such other equipment as may be necessary, with full right of ingress and egress to and from said premises, and the further right to do thereon acts necessary or convenient for the carrying out of the terms of this Agreement.

XI
"SELLER"

11.1 "Seller" is used collectively herein to refer to Union Oil Company of California and Marathon Oil Company. It is the intent of the parties hereto that each has executed this Agreement and has contracted herein in its individual capacity and to the extent of its respective, separate and distinct undivided interest only. It is

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understood that each seller company presently owns and holds an equal undivided interest in the gas to be sold under this Agreement and that, until further written notice from both of said companies, payment for gas delivered hereunder will be made by Buyer in equal amounts, one-half (1/2) of such payment to Union and one-half (1/2) to Marathon.

It is expressly agreed that the Seller has contracted individually hereunder and that nothing in this Agreement contained, expressed or implied, nor any operations conducted hereunder, shall create or be deemed to have created a partnership or association between the parties hereto or any of them.

IN WITNESS WHEREOF, the parties hereto have caused this Amendment of Gas Purchase Contract to be executed this 18th day of December, 1974.

UNION OIL COMPANY OF CALIFORNIA

By John R Fraser
Its Attorney-in-Fact

MARATHON OIL COMPANY

By B E McMillan
Senior Vice President

SELLER

ATTEST:

F. H. Brew
Assistant Secretary

ALASKA PIPELINE COMPANY

By

BUYER

ATTEST:

Richard J. Bourne
~~Assistant~~ Secretary

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EXHIBIT A

Attached to and incorporated in Amendment of Gas Purchase Contract, dated January 1, 1975, between UNION OIL COMPANY OF CALIFORNIA, hereinafter referred to as "Union", and MARATHON OIL COMPANY (formerly The Ohio Oil Company), hereinafter referred to as "Marathon", both companies hereinafter referred to collectively as "Seller", and ALASKA PIPELINE COMPANY, hereinafter referred to as "Buyer".

GENERAL TERMS AND CONDITIONS

A. MEASURING STATION

1. Buyer shall install, maintain and operate, at Buyer's own expense, at or near the existing point of delivery, a measuring station properly equipped with orifice meters, flange connections, orifice plates and other necessary equipment by which the volume of gas delivered hereunder shall be measured, and Seller, to the extent that Seller has the right to do so, hereby, grants to Buyer the right to install, maintain and operate such equipment. Volumes shall be computed and orifice meters shall be installed, maintained and operated as prescribed by the American Gas Association in Gas Measurement Committee Report Number 3, including the appendix thereto, as published April, 1955, and any subsequent amendments, additions or changes thereto as may be made from time to time by the A.G.A. Gas Measurement Committee. Seller shall have access to such metering equipment at reasonable hours, but the reading, calibrating and adjusting thereof and the changing of charts shall be done only by Buyer.

2. Seller shall install, maintain and operate, at its own expense such pressure regulators and check measuring equipment as it

shall desire, so installed as not to interfere with the operation of Buyer's measuring equipment. Buyer shall have access to such check measuring equipment at reasonable hours, but the reading, calibrating and adjusting thereof and the changing of charts shall be done only by Seller.

3. Each party shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment used in measuring deliveries hereunder. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its record and charts, together with calculations therefrom, for inspection and verification, subject to return within ten (10) days after receipt thereof.

4. In the event a meter is out of service, or registering inaccurately, the volume of gas delivered hereunder shall be estimated;

(a) By using the registration of any check meter or meters if installed and accurately registering, or in the absence of (a):

(b) By correcting the error if the percentage of error is ascertainable by calibration, test, or mathematical calculation or, in the absence of both (a) and (b), then:

(c) By estimating the quantity of delivery by deliveries during periods under similar conditions when the meter was registering accurately.

5. At least once each month Buyer shall verify the accuracy of Buyer's measuring equipment and Seller shall verify the accuracy of its check measuring equipment. If either party shall notify the other that it desires a special test of any measuring equipment, the parties shall cooperate to secure a prompt verification of the accuracy of such equipment. If either party at any time observes a variation between the delivery meter and the check meter, it will promptly notify the other party thereof and both parties will then cooperate to secure an immediate verification of the accuracy of such equipment. Each party shall give to the other notice of the time of all tests of meters reasonably in advance of the holding of such tests in order that the other party may conveniently have its representative present.

6. If, upon test, any measuring equipment is found to be in error not more than two per cent (2%), previous records of such equipment shall be considered accurate in computing deliveries hereunder; but such equipment shall be adjusted at once to record correctly. If, upon test, any measuring equipment shall be found to be inaccurate by an amount exceeding two per cent (2%), at a recording corresponding to the average hourly rate of flow for the period since the last preceding test, then any previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon, but in case the period is not known definitely or agreed upon such correction shall be for a period extending over one-half of the time elapsed since the date of last test, not exceeding a correction period of sixteen (16) days.

7. Each party shall preserve for a period of at least two (2)

years all test data, charts and other similar records.

B. MEASUREMENTS

1. The sales unit of the gas deliverable hereunder shall be one (1) Mcf of gas.

2. The volume of the gas delivered hereunder shall be determined as follows:

(a) The unit of volume for the purpose of measurement shall be one cubic foot of gas at a base temperature of sixty (60) degrees Fahrenheit and at a pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch absolute with correction for deviation from Boyle's Law. Computation of volumes shall be in accordance with applicable rules, regulations and orders promulgated by a recognized regulatory body.

(b) The average absolute atmospheric pressure shall be assumed to be fourteen and seven-tenths (14.7) pounds to the square inch, irrespective of actual elevation or location of the point or points of delivery above sea level or variations in such atmospheric pressure from time to time.

(c) The deviation of gas from Boyle's Law at the pressures, temperatures, and specific gravities under which the gas is delivered hereunder, shall be read from the A.G.A. convenient operating tables of "Supercompressibility Factors for Natural Gas", without adjustment of diluents, which have been developed

from the basic tables contained in the A.G.A. Gas Measurement Committee Report No. 3.

(d) The temperature of the gas passing the meters shall be determined by the continuous use of a recording thermometer so installed by Buyer that it may properly record the temperature of the gas flowing through the meters. The arithmetical average of the hourly temperature readings recorded each twenty-four (24) hour day shall be used in computing gas volumes for that date.

(e) Unless the parties hereto agree to the use of a spot test method, the specific gravity of the gas delivered hereunder shall be determined by the continuous use of an Acme recording gravitometer, or other standard gravitometer agreed upon by the parties hereto, so installed that it may properly record the specific gravity of the gas flowing through the meters. The arithmetical average of the specific gravity recorded during each twenty-four (24) hour day shall be used in computing gas volumes for that date. If the parties hereto agree to the use of a spot test method, such spot test shall be made with an Edwards type of gas balance, or by such other method as shall be agreed upon between the parties. If the spot test method is used, the specific gravity of the gas de-

livered hereunder shall be determined once monthly, or as much oftener as is found necessary in practice. The regular monthly test shall determine the specific gravity to be used in computation for the measurement of natural gas delivered, until the end of such month or until changed by special test; the special test to be applicable from the day made through the remaining days in such month.

C. QUALITY OF GAS

1. Seller agrees that:

(a) The gas delivered hereunder shall have a total heating value of not less than nine hundred and fifty (950) British thermal units per cubic foot. If at any time Seller shall become unable to produce gas possessing at least such total heating value, Buyer shall have the option from time to time to refuse to accept that part of Seller's gas which is so deficient so long as said heating value remains below nine hundred and fifty (950) British thermal units per cubic foot. In the event Buyer accepts delivery of said gas when the heating value thereof is below nine hundred and fifty (950) British thermal units per cubic foot, Buyer may reduce the total amount payable as the purchase price for gas delivered under this contract for each month during which such deficiency obtains by an amount de-

termined by multiplying such total amount by a fraction having as its numerator the average deficiency of British thermal units per cubic foot of gas below nine hundred and fifty (950) and its denominator nine hundred and fifty (950).

(b) Buyer shall have the right to determine, at such time or times as it may desire, the total heating value of the gas in British thermal units per cubic foot by means of some approved method of general use in the industry. Buyer shall give to Seller notice of the time of all tests for determining the British thermal unit content of the gas to be conducted by such party reasonably in advance of making the test in order that the other party may conveniently have its representative present. Should there be any material variance between tests by Buyer and Seller, a joint test will be run and will be controlling, effective from the first day of the calendar month preceding such joint test. The British thermal unit content per cubic foot shall be determined for a cubic foot of gas at a temperature of sixty degrees (60°) Fahrenheit when saturated with water vapor and at an absolute pressure equivalent to thirty inches (30") of mercury at thirty-two degrees (32°) Fahrenheit when the products of combustion are cooled to the initial temperature of gas and air and when the water formed by combustion is condensed to

the liquid state.

2. Seller agrees that the gas delivered hereunder:

(a) Shall not contain more than one (1) grain of hydrogen sulphide per one hundred (100) cubic feet of gas as determined by the Tutwiler test or some other quantitative test, mutually agreeable to the parties hereto, after the presence of hydrogen sulphide has been indicated by qualitative test.

(b) Shall not contain more than twenty (20) grains of total sulphur per one hundred (100) cubic feet of gas.

(c) Shall not contain in excess of:

(i) Three percent (3%) by volume of carbon dioxide;

(ii) One percent (1%) by volume of Oxygen.

(d) Shall have a temperature of not more than one hundred twenty degrees (120°) Fahrenheit.

(e) Shall not contain more than four (4) pounds of water per one million (1,000,000) cubic feet of gas.

3. In addition to meeting the above specifications, the gas delivered hereunder shall be commercially free from dust, gums, gum forming constituents, or other liquid or solid matter which might become separated from the gas in the course of transportation through pipelines.

4. In the event Buyer shall exercise its option to refuse to accept that part of Seller's gas not meeting any of the above quality specifications, Seller shall be free to sell such rejected gas to others.

D. STATEMENTS AND PAYMENTS

1. On or before the fifteenth (15th) day of each calendar month after deliveries of gas are commenced hereunder, Buyer shall render a statement to Seller showing the amount of gas delivered hereunder during the last preceding calendar month. Buyer agrees to make payment to Seller on or before the twenty-fifth (25th) day of each calendar month for all gas delivered or for which any payment is due hereunder for the preceding month.

2. Each party shall have the right at reasonable times to examine the books, records and charts of the other party to the extent necessary to verify the accuracy of any statement, charge or computation made pursuant to the provisions of any Article hereof. If any such examination reveals any inaccuracy in such billing theretofore made, the necessary adjustment in such billing and payments shall be promptly made; provided that no adjustment for any billing or payment shall be made after the lapse of one (1) year from the rendition thereof.

E. FORCE MAJEURE

1. In the event of either party hereto being rendered unable, wholly or in part, by force majeure to carry out its obligations under this Agreement, other than to make payments theretofore accrued hereunder, it is agreed that on such party giving notice and full particulars of such force majeure in writing or by telegraph or Telex to the other party as soon as possible after the occurrence of the cause relied on, then the obligations of the party giving such notice, so far as they are affected by such force majeure, shall be suspended during the continuance

of any inability so caused but for no longer period, and such cause shall as far as possible be remedied with all reasonable dispatch. The term "force majeure" as employed herein means an occurrence not within the control of the party claiming force majeure and which by the exercise of due diligence such party is unable to prevent or overcome, and, subject to the exercise of due diligence to prevent or overcome, such occurrence shall include acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests, and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, the necessity for making repairs to or alterations of machinery or lines of pipe, freezing of wells or lines of pipe, partial or entire failure of wells or sources of supply of gas, any act or omission by parties not controlled by the party having the difficulty, any act or omission (including failure to take gas) of a purchaser of gas from Buyer which is excused by any event or occurrence of the character herein defined as constituting force majeure, and any other causes, whether of the kind herein enumerated or otherwise, not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome; such term shall likewise include (a) in those instances where either party hereto is required to obtain servitudes, rights of way grants, permits or licenses to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in

acquiring, at reasonable cost and after the exercise of reasonable diligence, such servitudes, rights of way grants, permits or licenses, and (b) in those instances where either party hereto is required to furnish materials and supplies for the purpose of constructing or maintaining facilities or is required to secure permits or permission from any governmental agency to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such materials and supplies, permits and permissions. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty, and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of opposing party when such course is inadvisable in the discretion of the party having the difficulty.

F. WARRANTY OF TITLE

Seller hereby warrants the title to all gas delivered by Seller to Buyer under this Agreement, the right to sell the same and that it is free from all liens and adverse claims, and agrees, if notified thereof by Buyer, to indemnify Buyer against all suits, actions, debts, accounts, damages, costs, losses, and expenses arising from or out of any adverse legal claims of any and all persons to or against title to said gas. Seller agrees to pay or cause to be paid all taxes and assessments levied on the gas prior to its delivery to Buyer (subject to reimbursement as

provided in Article VII of this Gas Purchase Contract), and to pay or cause to be paid to the parties entitled thereto all royalties, overriding royalties or like charges against said gas or the value thereof. In the event any adverse claim of any character whatsoever is asserted in respect to title of any of said gas, Buyer may retain the purchase price thereof up to the amount of such claim without interest until such claim has been finally determined, as security for the performance of Seller's obligations with respect to such claim under this Section F, or until Seller shall have furnished bond to Buyer, in an amount and with sureties satisfactory to Buyer, conditioned for the protection of Buyer with respect to such claim.

G. OPERATION OF PROPERTIES

Seller shall have agents or employees available at all times to receive Buyer's dispatchers' requests for changes in rates of delivery of gas hereunder as required by Buyer from time to time.

REM
Bul

EXHIBIT B

Attached to and incorporated in the Amendment of Gas Purchase Contract, dated January 1, 1975, between UNION OIL COMPANY OF CALIFORNIA, hereinafter referred to as "UNION", and MARATHON OIL COMPANY (formerly The Ohio Oil Company), hereinafter referred to as "Marathon", both companies hereinafter referred to collectively as "Seller", and ALASKA PIPELINE COMPANY, hereinafter referred to as "Buyer".

UNSURVEYED LANDS:

PARCEL 1: Beginning at the northeast corner of surveyed Section 1, Township 4 North, Range 12 West, S.M. Alaska; thence South 1.5 miles; thence East 1.0 mile; thence North 1.5 miles; thence West 1.0 mile to the point of beginning; which when surveyed will probably be:

TOWNSHIP 4 NORTH, RANGE 11 WEST, S.M.:

Section 6: All
Section 7: North 1/2 - (960 acres; more or less)

The above described parcel of land being covered by that certain United States Oil and Gas Lease issued effective 10/1/58 and bearing serial register number A-028142, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.

SURVEYED LANDS:

PARCEL 2: TOWNSHIP 4 NORTH, RANGE 12 WEST, S.M.:

Section 1: Lots 1, 2, 4, 5, and E 1/2 E 1/2 - (249.20 acres)
Section 12: North 1/2 - (134.40 acres)

The above described parcel of land being covered by certain United States Oil and Gas Lease issued effective 11/1/58 and bearing serial register number A-028143, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367 dated 5/1/59.

(b) TOWNSHIP 5 NORTH, RANGE 11 WEST, S.M.:

Section 31: Lot 6 - All - (5.19 acres)

The above described parcel of land being covered by fee Oil and Gas Lease by and between Union Oil Company of California, as Lessee, and R. L. Schmidt, as Lessor, dated 3/20/59, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.

and containing in the aggregate, 2,797.54 acres, more or less.

PARCEL 3: (a) TOWNSHIP 5 NORTH, RANGE 11 WEST, S.M.:

Section 29: West 1/2 - (320.00 acres)
Section 30: Lots 5, 6, 7, 8, 9, 11, 12, 13, 14, 15 - and E 1/2 - (372.23 acres)

The above described parcel of land being covered by that certain United States Oil and Gas Lease issued effective 10/1/55 and bearing serial register number A-028056, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.

(b) TOWNSHIP 5 NORTH, RANGE 11 WEST, S.M.:

Section 30: Lots 3 and 10 - (26.71 acres)

The above described parcel of land being covered in fee Oil and Gas Lease by and between Union Oil Company of California, as Lessee, and L. B. Edelman, et ux, as Lessor, dated 2/28/59, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.

(c) TOWNSHIP 5 NORTH, RANGE 11 WEST, S.M.:

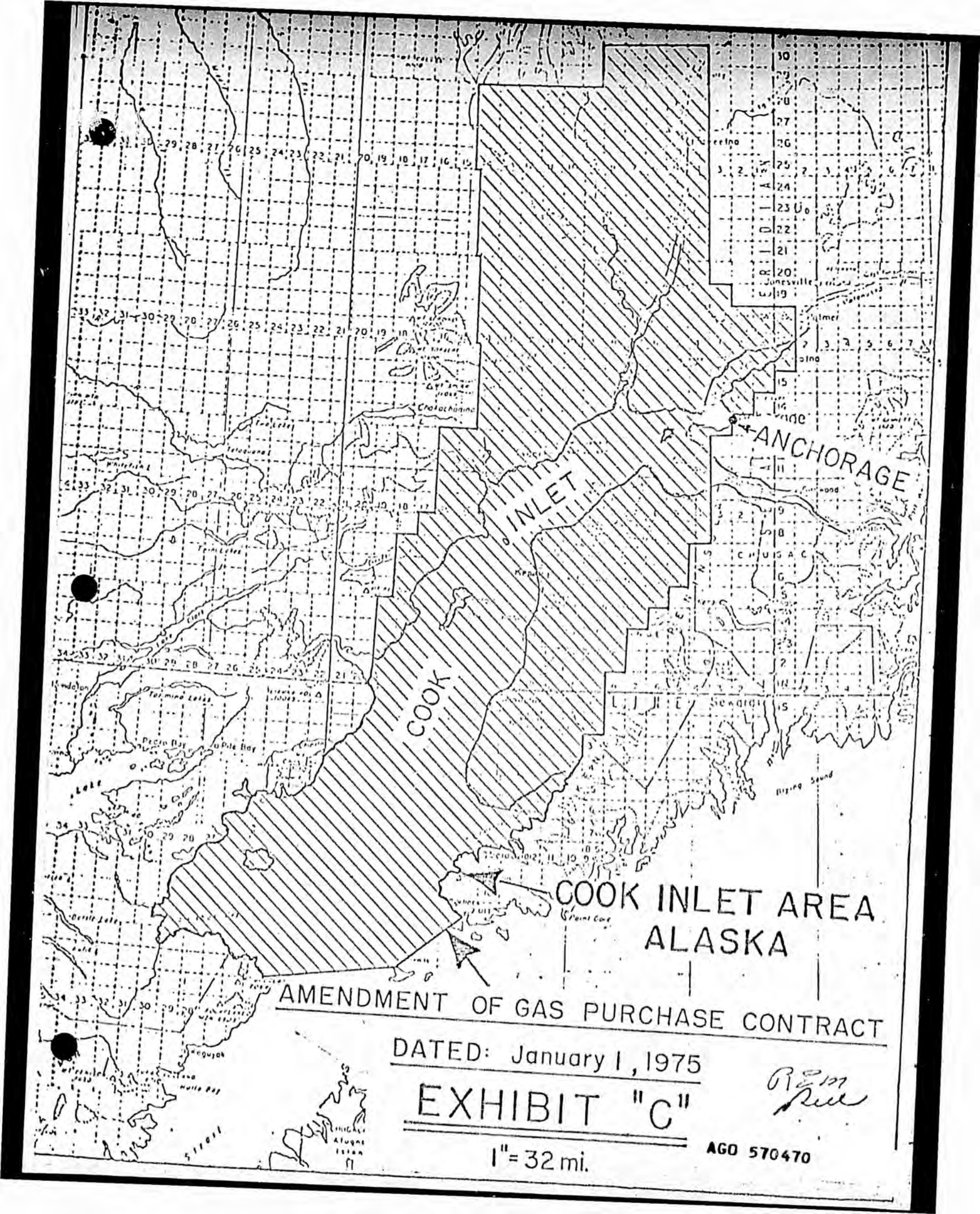
Section 30: Lot 16 - (5.09 acres)

The above described parcel of land being covered by fee Oil and Gas Lease by and between Union Oil Company of California, as Lessee, and C. E. Johnson, as Lessor, dated 3/21/59, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.

PARCEL 4: (a) TOWNSHIP 5 NORTH, RANGE 11 WEST, S.M.:

Section 31: Lots 3, 4, 5, 7, 8, 10 and E 1/2 - (404.72 acres)
Section 32: West 1/2 - (320.00 acres)

The above described parcel of land being covered by that certain United States Oil and Gas Lease issued effective 10/1/55 bearing serial register number A-028055, and which is included in the Kenai Unit area, Third Judicial Division, State of Alaska, No. 14-08-001-6367, dated 5/1/59.


COOK INLET
ANCHORAGE
COOK INLET AREA
ALASKA
AMENDMENT OF GAS PURCHASE CONTRACT
DATED: January 1, 1975
EXHIBIT "C"
1" = 32 mi.
AGO 570470

T12N - R1E	All Sections
T12N - R1W	All Sections
T12N - R2W	All Sections
T12N - R3W	All Sections
T12N - R4W	All Sections
T12N - R5W	Sections 1-28, 35-36
T12N - R6W	Sections 1, 11-14, 23-24
T13N - R1E	All Sections
T13N - R1W	All Sections
T13N - R2W	All Sections
T13N - R3W	All Sections
T13N - R4W	Sections 1, 11-17, 19-36
T13N - R5W	Sections 22-28, 31-36
T14N - R1E	All Sections
T14N - R1W	All Sections
T14N - R2W	All Sections
T14N - R3W	Sections 1-4, 9-17, 20-36
T15N - R1E	All Sections
T15N - R1W	All Sections
T15N - R2W	All Sections
T15N - R3W	Sections 13, 23-27, 33-36
T16N - R1E	Sections 13-36
T16N - R1W	Sections 13-36
T16N - R2W	Sections 23-27, 33-36

The Section Numbers given above are inclusive in denoting those Sections lying within the "Service Area" boundaries.

All Townships and Ranges noted in the above description and notation are those from the Seward Base Meridian, State of Alaska.

May 1, '67 Contract and
3/12/76 Amendment

Alaska Gas and Service Company

GENERAL OFFICES LOCATED AT 3000 SPENARD ROAD
P. O. BOX 6288 ANCHORAGE, ALASKA 99502 / PHONE (907) 277-5551
TELEX 25-187

May 16, 1977

Ms. Elke Kallab
Research Analyst
Legislative Affairs Agency
Pouch Y
Juneau, Alaska 99811

Dear Ms. Kallab:

Enclosed are copies of the various gas supply contracts you requested. You will note the North Road contract expired on May 1, 1977. Since that date we have operated without a contract, but with a letter offer of a two month extension without change of terms from Marathon Oil Company. Upon receipt of a similar offer from Union Oil Corporation we will execute the acceptances. If the royalty contract is not approved we will be required to negotiate for a new longer term contract in the very near future.

I have discussed with the APUC the information you have requested and have been advised they are forwarding a copy of the order relating to the transportation by Union-Marathon from the Kenai Field to the North Road area.

Quite frankly, we believe gas delivered into our system at 75¢/Mcf is an outstanding bargain at present. We are becoming increasingly concerned that the Japanese will continue to enjoy it while our customers are forced to pay a much higher price based on current market conditions.

Should you require additional information please advise me.

Very truly yours,

Bill B. Hickman
Vice President and Treasurer

BBH/pm

AGO 570472

UNION 76

March 12, 1976

Alaska Pipeline Company
P. O. Box 6288
Anchorage, AK 99502

ATTN: Mr. Dale Teel

Gentlemen:

Please refer to that certain "Gas Sales Agreement" dated May 1, 1967, between Union Oil Company of California (Union) and Marathon Oil Company as Seller and Alaska Pipeline Company (Alaska) as Buyer involving certain taps and the delivery of gas off of Seller's Kenai-Nikiski Pipeline until an aggregate quantity of 10,000,000 MCF of gas has been delivered and purchased thereunder, or for a period of ten (10) contract years, whichever first occurs.

You now expect to complete the receipt and purchase of 10,000,000 MCF of gas in the first part of this year but wish to continue receiving gas from us to meet your current obligations through May 1, 1977. To accommodate you we are willing to amend the agreement to provide for this and certain other changes.

Now therefore the aforesaid "Gas Sales Agreement" dated May 1, 1967 as to Union's obligations only thereunder is hereby amended to delete in their entirety Section 5.1, Article VI and VIII in the body of the agreement and Article V in Exhibit "A" attached thereto, and to make substitutions and additions thereto as follows:

In the body of the agreement:

5.1 Subject to the provisions of 5.2 below the price to be paid by Buyer for gas delivered during any month hereunder shall be as follows:

a. Until Union's share of 10,000,000 MCF has been delivered the same price provided for deliveries of gas to Alaska Pipeline Company under that certain "Gas Purchase Contract" dated May 13, 1960, as amended, plus one and one-half (1-1/2) cents per MCF, and

b. For all gas deliveries which exceed Union's share of 10,000,000 MCF the price shall be the same as provided for above in Section 5.1 (a) plus the "Special Deliverability Charge" as set forth in Sections 3.1 and 3.2 of that certain "Amendment of Gas Purchase Contract" dated January 1, 1975 to that certain "Gas Purchase Contract" dated May 13, 1960 by and between Buyer and Seller hereinafter called "Said Contract".

5.3 For all of Union's share of "excess royalty payments" arising from gas sold hereunder Buyer agrees to reimburse Union the same as is provided for in Section 7.3 of Said Contract.

VI QUANTITY OF GAS

6,1 Not withstanding any other provision of this agreement, Union shall not be obligated hereunder to deliver to Buyer nor shall Buyer be required to purchase, more than Union's share of 10,000 MCF during any day. When an aggregate of Union's share of 10,000,000 MCF of gas has been received and delivered hereunder, then Buyer may receive and Union shall deliver during the remaining term hereof Union's share of Buyer's requirements of gas from "Seller's Gas Reserves" as set forth in Section 2.1 of Said Contract. Gas delivered hereunder shall not be used to calculate Buyer's obligation under Section 2.5 of Said Contract. Union shall have the right to terminate this agreement by giving written notice to Buyer in the event either:

a. Buyer fails for thirty (30) days to accept and receive gas hereunder or

b. If at any time Buyer contracts with a third party for gas from a source other than the source of deliveries hereunder.

VIII TERM

8.1 This agreement effective May 1, 1967 shall continue and remain in effect until May 1, 1977.

Section 2.1(d) of Exhibit "A" is changed to read:

contain not more than four (4) pounds of water per million (1,000,000) cubic feet.

Except as hereinabove specifically set forth, all of the terms and conditions of said "Gas Sales Agreement" dated May 1, 1967 between Union and Alaska shall remain in full force and effect.

If you agree to the foregoing, please so indicate by signing and returning one copy of this letter to us.

Very truly yours,

UNION OIL COMPANY OF CALIFORNIA

By _____

Agreed March 18, 1976

ALASKA PIPELINE COMPANY

By _____

AGO 570475

W. A. Sackmann
Attorney

Marathon
Oil Company

Findlay Ohio 45840
Telephone 419/422 2121

March 10, 1976

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

Attention: Mr. Dale Teel, President

Re: Gas Sales Letter Agreement

Dear Mr. Teel:

In the absence of Mr. Emery, I am sending on to you for execution by Alaska Pipeline Company a Gas Sales Letter Agreement which I believe meets the understanding of yourself and Mr. Emery in connection with gas for the "North Kenai Road Market."

If the enclosed meets with your approval, it would be appreciated if you would return a copy of same to me after your execution thereof.

I assume that you will be receiving a somewhat similar letter from Union Oil Company of California so that this matter will be handled in a manner satisfactory to all concerned.

Yours very truly,

W. A. Sackmann

WAS:blc
Enclosures

AGO 570476

R E McMillen
Senior Vice President
Production US & Canada

Marathon
Oil Company

Findlay Ohio 45840
Telephone 419/422 2121

March 8, 1976

Alaska Pipeline Company
P. O. Box 6288
Anchorage, Alaska 99502

Re: Gas Sales Letter Agreement

Gentlemen:

The following shall set forth Marathon Oil Company's (Marathon) and Alaska Pipeline Company's (Alaska Pipeline) agreement with respect to the sale of natural gas to Alaska Pipeline from and after the termination of that certain Gas Sales Agreement dated May 1, 1967, ("1967 Agreement") which shall occur when the aggregate quantity of ten million Mcf shall have been delivered thereunder:

A. Consideration

The price per Mcf to be paid to Marathon by Alaska Pipeline for gas delivered hereunder during any month of the term hereof shall be the price per Mcf provided to be paid by Alaska Pipeline for deliveries of gas to Alaska Pipeline Company during such month under that certain Gas Purchase Contract dated May 13, 1960, as amended by agreement of the parties effective the 1st day of January, 1975 ("Contract"), plus one and one-half (1 1/2) cents per Mcf. In addition, there shall be paid, the "Special Deliverability Charge" under 3.1 of said Contract. The aggregate sum payable, as adjusted, shall initially be 45.7¢ per Mcf. Said sum payable hereunder shall be subject to further adjustment during the term hereof pursuant to the provisions of Sections 3.2, 7.2 and 7.3 of said Contract.

B. Quantity of Gas

Notwithstanding any other provision of said Contract or this Letter Agreement, the maximum quantity Marathon shall be required to deliver hereunder in any one day shall be one-half of 10,000 Mcf. This quantity shall be in addition to the

"Daily Contract Quantity" set forth in Section 2.4 of said Contract. Quantities delivered pursuant to this Gas Sales Letter Agreement shall not be used to calculate Alaska Pipeline's obligations under 2.5 of said Contract.

C. Term

This Letter Agreement shall be effective from the date hereof to May 1, 1977; provided however, deliveries hereunder shall not commence until total deliveries under said 1967 Agreement shall equal ten (10) million Mcf.

D. Other Terms and Conditions

All other terms and conditions of this Letter Agreement shall be governed by said Contract; provided, however, the Points of Delivery hereunder shall be those specified in Section 3.1 of said 1967 Agreement. It is specifically understood and agreed that any quantities delivered under this Gas Sales Letter Agreement shall be applied against the maximum total quantity of five hundred fifty billion (550,000,000,000) cubic feet of gas set forth in Article II of said Contract.

This Letter Agreement, when executed, will supersede all prior letters, documents and understandings between our respective companies relating to this sale.

To evidence your full agreement with the terms and conditions hereof, please return to us one executed copy of this letter.

Yours very truly,

MARATHON OIL COMPANY

wsd

By _____
R. E. McMillen
Senior Vice President

Accepted and agreed to

_____, 1976.

ALASKA PIPELINE COMPANY

DI 3/19/76

By _____

This is effective version HR 3/1/76

GAS SALES AGREEMENT

THIS AGREEMENT, made and entered into as of the first day of May, 1967, by and between UNION OIL COMPANY OF CALIFORNIA and MARATHON OIL COMPANY (both hereinafter referred to collectively as "Seller"); and ALASKA PIPELINE COMPANY (hereinafter referred to as "Buyer").

W I T N E S S E T H :

WHEREAS, Seller has natural gas producing properties located on the Kenai Peninsula of the State of Alaska, and has constructed and will operate a large diameter pipeline (hereinafter referred to as the Kenai-Nikiski Pipeline) to transport gas from said producing properties to the vicinity of Nikiski, Alaska, in furtherance of its own project (hereinafter referred to as the "Nikiski Project") or other projects as may be determined by Seller which are unrelated to sale of gas to Alaska Pipeline Company, and

WHEREAS, Buyer desires to purchase natural gas from Seller for use, including resale, at certain delivery points on Seller's Kenai-Nikiski pipeline, and

WHEREAS, Seller is willing to sell, upon the terms, conditions and volume limitations set forth in this Agreement, certain quantities of natural gas to Buyer; provided, however, that such sale to Buyer shall be subordinate to the principal purpose of Seller in transporting natural gas for its other projects, and shall not impede or interfere with the supply and transportation of Seller's gas for Seller's said projects.

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements herein contained, Seller and Buyer agree as follows:

I. DEFINITIONS

Except where the context otherwise indicates another or different meaning or intent, the following terms as used herein and in Exhibit A attached hereto and incorporated herein by this reference for all purposes shall be construed to have the following meanings:

1.1 The term "day" shall mean a period of twenty-four (24) consecutive hours beginning and ending at eight o'clock a.m., Alaska Standard Time.

1.2 The term "month" shall mean a period beginning at eight o'clock a.m. on the first (1st) day of a calendar month and ending at eight o'clock a.m. on the first (1st) day of the next succeeding calendar month.

1.3 The term "contract year" shall mean a period of twelve (12) months beginning with the effective date hereof and any anniversary of such date.

1.4 The term "calendar year" shall mean that period of time commencing January 1 and ending December 31 of any year.

1.5 The term "gas" shall mean natural gas meeting the standards set forth in Exhibit A annexed to this Agreement.

1.6 The term "Mcf" shall mean one thousand (1,000) cubic feet of gas.

1.7 The term "BTU" shall mean British Thermal Unit.

1.8 The term "Buyer's Requirements" shall mean the quantities of natural gas up to the maximum quantity hereinafter provided, which are required by Buyer for deliveries at one or more of the delivery points also hereinafter provided.

II. SCOPE OF AGREEMENT

2.1 It is expressly agreed that, notwithstanding the agreement of the parties hereto that the sales of gas contemplated herein are subordinate to Seller's operation of the Kenai-Nikiski pipeline for its other projects, this

Agreement shall be binding upon the parties hereto as of the effective date hereof. It is agreed to by and between the parties hereto that Seller shall sell and deliver or cause to be delivered, such portion of Buyer's Requirements as Buyer chooses to receive, subject to the terms, conditions and limitations set forth hereinafter and in Exhibit A hereto.

III. POINTS OF DELIVERY

3.1 A point of delivery shall be the downstream flange of a block valve installed by Buyer and located between Seller's Kenai-Nikiski pipeline and Buyer's gas receiving facilities. Gas sold by Seller to Buyer hereunder shall be delivered to Buyer at one or more points of delivery located as follows:

(i) Near the point of intersection between Seller's Kenai-Nikiski pipeline and the North line of Section 27, Township 7 North, Range 12 West, Seward Base and Meridian, Alaska.

(ii) Near the intersection of North Kenai Road with the south line of Section 23, Township 6 North, Range 12 West, Seward Base and Meridian, Alaska.

(iii) Near the center of the NW 1/4 of the NW 1/4 of Section 27, Township 7 North, Range 12 West, Seward Base and Meridian, being the point of delivery of gas to be delivered to Collier Carbon and Chemical Company's ammonia facilities at or near said point.

3.2 Title to and ownership of the gas shall pass to and absolutely vest in Buyer at said points of delivery.

3.3 Seller shall have exclusive custody and control of the gas to be delivered hereunder prior to delivery to Buyer. Upon delivery to Buyer, Buyer

AGO 570481

shall be in exclusive custody, control and possession thereof and shall indemnify Seller and hold it harmless from any injury or damage occurring at or after point or points of delivery.

IV. PRESSURE

4.1 The gas delivered hereunder shall be delivered by Seller into Buyer's gas receiving facilities at the pressure existing in Seller's line from time to time at said point or points of delivery, provided that such pressure shall not be greater than 1300 psig nor less than 200 psig. Buyer shall, at the point or points of delivery, install and exclusively operate all necessary pressure reduction equipment and other facilities necessary to receive the gas delivered hereunder.

V. PRICE - TAXES

5.1 The price per Mcf to be paid to Seller for gas delivered hereunder during any month shall be the price per Mcf provided to be paid by Alaska Pipeline Company for deliveries of gas to Alaska Pipeline Company during such month under that certain contract dated May 13, 1960, as amended, plus one and one-half (1-1/2) cents per Mcf. If, during the term hereof, said contract dated May 13, 1960, as amended, terminates or deliveries thereunder are suspended for a period of at least 30 consecutive days, then, and in either of said events, the price to be paid by Buyer to Seller for gas delivered hereunder after such termination or during such suspension, as the case may be, shall be (a) 25-1/2 cents per Mcf during suspensions occurring prior to May 1, 1972, or during that portion of the term hereof which is subsequent to such termination and prior to May 1, 1972, and (b) 26-1/2 cents per Mcf during suspensions occurring after May 1, 1972, or during

that portion of the term hereof which is subsequent to the date of such termination or May 1, 1972, whichever is the later date.

5.2 Any sales, transactions, occupations, service, production, severance, gathering, export or excise tax, assessment or fee levied, assessed or fixed by the United States, State of Alaska or other governmental authority and taxes of similar nature or equivalent in effect (not including income, excess profits, capital stock, franchise, or general property taxes) in addition to or greater than those, if any, being levied, assessed or fixed on the date of execution hereof, in respect of or applicable to the natural gas to be delivered by Seller to Buyer hereunder and for which Seller may be liable during any month either directly or indirectly through any obligation to reimburse others, are hereinafter collectively referred to as "additional tax". It is expressly understood and agreed that so long as the additional tax shall be in effect:

(a) Buyer shall reimburse Seller for all additional tax. In the event all or any part of additional tax liability of Seller is not determined or not determinable by the end of the month, then such additional amount required in respect of such liability not determined or not determinable shall be set forth for all such months in any calendar year in a statement to be rendered by Seller to Buyer by April 1 of the following year and Buyer shall pay the amount due pursuant to such statement on or before May 1 of such following year.

(b) Seller shall have the right, at its expense, to pay under protest or contest the validity of any additional tax imposed upon or payable by it, but shall have no obligation so to do. If any additional tax is finally determined by a court of competent jurisdiction to be invalid as to gas delivered hereunder, and

Seller obtains a refund thereof from the taxing authority, Seller will pay to Buyer such refunded amounts (plus the interest, if any, received by Seller on amounts so refunded) less Seller's reasonable and necessary expenses incurred in connection with obtaining any such refund.

VI. QUANTITY OF GAS

6.1 It is agreed that since Buyer's ultimate requirements for natural gas are not now subject to reasonable estimation, the following procedure shall govern the determination of the quantities of gas available for purchase by Buyer from Seller:

Upon execution of this contract and thereafter at least six months prior to the beginning of each contract year Buyer shall notify Seller in writing of the Daily Maximum Quantity of gas to be purchased by Buyer from Seller during the ensuing contract year. Buyer may from time to time increase such Daily Maximum Quantity by giving Seller written notice of such increase at least thirty (30) days prior to such increase. The Annual Contract Quantity shall be fifty percent (50%) of each such Daily Maximum Quantity so designated by Buyer multiplied by the number of days in the contract year applicable to each such Daily Maximum Quantity.

6.2 Seller agrees to have available for delivery and sale to Buyer the applicable Daily Maximum Quantity on each day of the ensuing contract year. Buyer agrees to receive and pay for, or to pay for if available and not received, the Annual Contract Quantity.

6.3 Should Buyer, at the end of any contract year, fail to have taken during such year the applicable Annual Contract Quantity of gas Buyer is obligated to purchase hereunder, Buyer shall, nevertheless, pay Seller for the quantity of

gas Buyer failed to take during such contract year. Buyer shall make such payment within sixty (60) days after the end of such contract year. The price per one thousand (1,000) cubic feet shall be the same as the volume weighted average price per one thousand (1,000) cubic feet paid by Buyer for gas actually received from Seller hereunder during the same contract year.

6.4 If for any contract year Buyer pays for any quantity of gas not actually received by it, Buyer shall thereafter be entitled to receive such quantity of gas during the term of this contract without further payment; except, Buyer shall pay the differential in prices, if any, between that existing when such payments were made and that applicable at the time of taking. Such quantity of gas so taken shall be in addition to the Annual Contract Quantity which Buyer is otherwise obligated to purchase and receive during any such contract year.

6.5 Notwithstanding any other provision of this Agreement, Seller shall not be obligated hereunder to deliver to Buyer, nor shall Buyer be required to purchase, more than 10,000 Mcf during any day, nor an Aggregate Contract Quantity of gas in excess of 10,000,000 Mcf during the entire term of this contract. Provided that if at any time while the Annual Contract Quantity is less than 1,000,000 Mcf Buyer purchases gas from a third party and such gas is used to serve a market theretofore served by gas purchased hereunder, with the result that such use results in a reduction in the annual volumes of gas taken by Buyer under this Agreement, the gas so used shall be deemed "extraneous gas". From and after Buyer's utilization of extraneous gas, the quantities of gas deliverable under this contract during the contract year beginning after initiation of extraneous purchases by Buyer and during each contract year thereafter, for the remainder of the term of this contract, shall be:

"(a) Annual Contract Quantity shall be a quantity of gas

equal to the actual deliveries hereunder during the twelve months immediately preceding the month in which extraneous purchases by Buyer are initiated.

"(b) Daily Maximum Quantity shall be a quantity of gas equal to 2/365 of the Annual Contract Quantity.

"(c) Aggregate Contract Quantity shall be a quantity of gas equal to the sum of (1) the volume of gas theretofore delivered to Buyer hereunder, (2) the volume thereafter to be delivered hereunder (Annual Contract Quantity multiplied by the number of years remaining in the term hereof), and (3) the volume of gas Buyer has theretofore paid for but not received."

VII. PAYMENT

7.1 On or before the fifteenth (15th) day of each calendar month after deliveries of gas are commenced hereunder, Buyer shall render statement to Seller showing the amount of gas delivered hereunder during the last preceding month. All payments due to be made hereunder shall be made on or before the twenty-fifth (25th) day of each month for amounts accruing during the preceding calendar month, and shall be paid to Seller at the address hereinafter set forth in Article IX.

7.2 Should Buyer fail to pay the full amount due Seller when same is due, as herein provided, interest thereon shall accrue at the rate of eight per cent (8%) per annum from the date when such payment is due until the same is paid. If such failure to pay continues for sixty (60) days, Seller may at any time thereafter while Buyer is in default cancel this Agreement or suspend deliveries of gas hereunder, but the exercise of such rights shall be in addition to any and all

other remedies available to Seller.

7.3 Each party shall have the right at reasonable times to examine the books, records and charts of the other party to the extent necessary to verify the accuracy of any statement, charge or computation made pursuant to the provisions of any Article hereof. If any such examination reveals any inaccuracy in such billing theretofore made, the necessary adjustment in such billing and payments shall be promptly made; provided that no adjustment for any billing or payment shall be made after the lapse of one (1) year from the rendition thereof.

VIII. TERM

8.1 This Agreement shall be effective from the date hereof and shall continue and remain in effect (1) until an aggregate quantity of 10,000,000 Mcf of gas has been delivered and purchased hereunder, or (2) for a period of ten (10) contract years, whichever occurs first.

IX. ADDRESSES

9.1 Until the other parties are otherwise notified in writing by Union, the address of Union is and shall remain as follows:

Union Oil Company of California
2805 Denali Street
Anchorage, Alaska 99503

and, unless the other parties are otherwise notified in writing by Marathon, the address of Marathon is and shall remain as follows:

Marathon Oil Company
550 South Flower Street
Los Angeles, California 90017

and, unless Seller is otherwise notified in writing by Alaska, the address of

AGO 570487

Buyer is and shall remain as follows:

Alaska Pipeline Company
P. O. Box 6554
Houston, Texas 77005

All notices required to be given in writing hereunder shall be sent by air mail, postage prepaid, to the respective parties at such addresses or such other addresses as the parties respectively shall have previously designated by written notice, and all notices required herein to be given by Buyer shall be given to both Union and Marathon.

X. MISCELLANEOUS

10.1 No waiver by either party hereto of any one or more defaults by the other in the performance of any provisions of this Agreement shall operate or be construed as a waiver of any future default or defaults, whether of like or different character.

10.2 This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective and legal representatives, successors and assigns. Without limitation upon Seller's obligation to perform hereunder, it is expressly agreed that this Agreement does not constitute any charge or burden upon Seller's properties.

XI. USE OF TERM "SELLER"

11.1 The term "Seller" is used collectively herein to refer to Union Oil Company of California and Marathon Oil Company solely for the purposes of convenience, and it is the specific intent of the parties hereto that each has executed this Agreement and has contracted herein independently and to the extent of its separate interest only. It is understood that each Seller company presently

owns and holds an undivided interest in the gas to be sold under this contract and that, until further written notice from both of said companies, payment for gas delivered hereunder will be made by Buyer in equal amounts, one half of such amount to Union, and one half to Marathon.

11.2 It is expressly agreed that the relation of the parties hereto is that of independent contractors and nothing in this Agreement contained, expressed or implied, nor any operations conducted hereunder, shall create or be deemed to have created a partnership or association between the parties hereto, or any of them.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the day and date first above mentioned.

UNION OIL COMPANY OF CALIFORNIA

By_____
Attorney-in-Fact

ATTEST:

MARATHON OIL COMPANY

_____

By_____
Vice President

"SELLER"

ATTEST:

ALASKA PIPELINE COMPANY

_____

By_____

"BUYER"

AGO 570489

EXHIBIT "A"

Attached to and incorporated in Gas Sales Agreement dated as of May 1, 1967, between UNION OIL COMPANY OF CALIFORNIA and MARATHON OIL COMPANY (both hereinafter referred to as "Seller"), and the ALASKA PIPELINE COMPANY (hereinafter referred to as "Buyer").

GENERAL TERMS AND CONDITIONS

I. MEASUREMENT

1.1 Except for the determination of heating value, the unit of volume for measurement of gas delivered hereunder shall be one (1) cubic foot of gas at a base temperature of sixty degrees (60°) Fahrenheit and at a pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch absolute. All fundamental constants, observations, records, and procedures involved in the determination of the quantity of gas delivered hereunder shall, unless otherwise specified herein, be in accordance with the American Gas Association's Gas Measurement Committee Report No. 3 dated April 1, 1955, as now and from time to time amended and supplemented, except that the combined Reynolds number and expansion factor and manometer factor shall be assumed to be one (1). The deviation of the gas from Boyle's Law at the pressures, temperatures, and specific gravities under which the gas is measured hereunder, shall be read from the A.G.A. convenient operating tables of "Supercompressibility Factors for Natural Gas", without adjustment for diluents, which have been developed from the basic tables contained in the A.G.A. Gas Measurement Committee Report No. 3. All quantities given herein and in the contract to which this Exhibit is attached, unless otherwise expressly stated, are in terms of such unit.

1.2 Buyer shall install, operate and maintain at its sole cost and expense a measuring station or stations located at the point or points of delivery. Each

such measuring station shall be equipped with an orifice meter, or other type of standard make and design commonly acceptable in the industry, so as to accomplish the accurate measurement of gas delivered hereunder. Seller shall have access to such measuring equipment at reasonable hours, but the calibrating, adjustment thereof and the changing of charts shall be done by Buyer. Reading of charts shall be performed by an independent chart reading firm acceptable to both Buyer and Seller at Buyer's expense.

1.3 Seller may, at its option, install, maintain and operate, at its own cost and expense, such check measuring equipment as it shall desire, so installed as not to interfere with the operation of Buyer's measuring equipment. Buyer shall have access to such check measuring equipment at reasonable hours, but the reading, calibrating and adjusting thereof and the changing of charts shall be done by Seller. Buyer, so far as it has the right to do so, shall provide Seller, free of charge, with an adequate site or sites for Seller's check metering equipment and shall grant to Seller the rights of ingress and egress.

1.4 The temperature of the gas flowing through each meter shall be determined by the continuous use of a recording thermometer so installed by Buyer that it may properly record the temperature of the gas flowing through said meter. The arithmetical average of the hourly temperature readings recorded while gas is flowing during each day shall be used in computing gas volumes for that day.

1.5 Unless the parties hereto agree to the use of a spot test method, the specific gravity of the gas delivered hereunder shall be determined by the continuous use of an Acme recording gravitometer, or other standard gravitometer agreed upon by the parties hereto, furnished and installed by Buyer so that it may properly

record the specific gravity of the gas flowing through each meter. The arithmetical average of the specific gravity recorded while gas is flowing during each day shall be used in computing gas volumes for that day. If the parties hereto agree to the use of a spot test method, such spot test shall be made with an Edwards type of gas balance, or by such other method as shall be agreed upon between the parties. If the spot test method is used, the specific gravity of the gas delivered hereunder shall be determined once every three (3) months, or as often as is found necessary in practice. The regular periodic test shall determine the specific gravity to be used in computation for the measurement of natural gas delivered, until the end of such test period or until changed by special test; the special test to be applicable from the day made through the remaining days in such test period.

1.6 Buyer shall test and make any necessary adjustments to its gas measuring equipment at least once every month and additionally as the situation may require. Seller may, at its option, be present for such tests and adjustments. Buyer shall give Seller notice of the time of all such tests sufficiently in advance of holding same. For the purpose of measurement and meter calibration, the average absolute atmospheric pressure shall be assumed to be fourteen and seven-tenths (14.7) pounds to the square inch, irrespective of actual elevation or location of the point of delivery from sea level or variations in such atmospheric pressure from time to time.

1.7 If, upon any test, any measuring equipment is found to be inaccurate by no more than two per cent (2%), previous readings of such equipment shall be considered correct in computing the volumes of gas delivered hereunder, but such equipment shall be adjusted at once to read accurately. If, for any reason, any measuring

AGO 570492

equipment shall be found to be inaccurate by an amount exceeding two per cent (2%) at a reading corresponding to the average rate of flow for the period since the last preceding test, then any previous readings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon; in case the period is not know definitely or agreed upon, such correction shall be for a period extending over one-half of the time elapsed since the date of the last test, not exceeding a correction period of sixteen (16) days.

1.8 If, for any reason, the measuring equipment is out of service or out of repair so that the quantity of gas cannot be ascertained or computed from the reading thereof, the quantity of gas delivered hereunder during the period such equipment is out of service or repair shall be estimated and agreed upon by the parties hereto upon the basis of the best available data, using the first of the following methods which is feasible:

(a) By using the registration of any check measuring equipment if installed and accurately registering.

(b) By correcting the error if the percentage of error is ascertainable by calibration, test or mathematical calculation.

(c) By estimating the quantity delivered by using deliveries during a period under similar conditions when the measuring equipment was registering accurately.

1.9 Buyer shall have the right to determine, at such time or times as it may desire, the total heating value of the gas in BTUs per cubic foot by means of some approved method of general use in the industry. Buyer shall give to Seller notice of the time of all tests for determining the BTU content of the gas reasonably in advance of making the test in order that Seller may conveniently have representatives present.

AGO 570493

Should there be any material variance between tests by Buyer and Seller, a joint test will be run and shall be controlling, effective from the first day of the month preceding such joint test. BTU content per cubic foot shall be determined for a cubic foot of gas at a temperature of sixty degrees (60°) Fahrenheit when saturated with water vapor and at an absolute pressure equivalent to thirty inches (30") of mercury at thirty-two degrees (32°) Fahrenheit when the products of combustion are cooled to the initial temperature of gas and air and when the water formed by combustion is condensed to the liquid state.

1.10 Each party shall preserve all original test data, charts and similar records in such party's possession and same shall be kept on file for a period of three (3) years for the mutual use of the parties hereto. Upon request of Seller, Buyer shall submit to Seller records and charts from such equipment, subject to return by Seller within thirty (30) days after receipt thereof.

II. QUALITY OF GAS

2.1 Seller agrees that the gas delivered hereunder shall:

(a) Be commercially free from dust, gums, gum forming constituents, or other liquid or solid matter which might become separated from the gas in the course of transportation through Buyer's system;

(b) Contain not more than one (1) grain of hydrogen sulphide per one hundred (100) cubic feet of gas as determined by the Tutwiler test or some other quantitative test, mutually agreeable to the parties hereto after the presence of hydrogen sulphide has been indicated by qualitative test;

(c) Contain not more than twenty (20) grains of total sulphur per one hundred (100) cubic feet of gas;

(d) Contain not more than two (2) pounds of water per one million (1,000,000) cubic feet;

(e) Contain not more than three per cent (3%) by volume of carbon dioxide;

(f) Contain not more than one per cent (1%) by volume of oxygen; and

(g) Have a total heating value of not less than nine hundred fifty (950) BTUs per cubic foot. If at any time Seller shall become unable to deliver gas possessing at least such total heating value, Buyer shall have the option from time to time to refuse to accept that part of Seller's gas which is so deficient. In the event Buyer accepts delivery of said gas when the heating value thereof is below nine hundred fifty (950) BTUs per cubic foot, Buyer may reduce the purchase price for gas delivered during any month such BTU deficiency occurs by an amount determined by multiplying the stated price by the fraction, $\frac{950 - A}{950}$ where A is the volume weighted average BTU content per cubic foot of gas actually delivered during such month.

III. FORCE MAJEURE

3.1 In addition to the rights otherwise reserved herein, it is agreed that if performance by either party of any of its obligations hereunder (other than obligations to make payments of money hereunder) is prevented or delayed by force majeure, such obligations shall be suspended during the continuance of the prevention or delay so caused, and the party affected shall not be liable to the other party in damages or otherwise by reason thereof. Upon the occurrence of an event constituting force majeure, the party having the difficulty shall give notice of force majeure by telegraph to the other party as soon as reasonably possible after the occurrence of the cause relied upon, and such cause of force majeure shall, so far as possible, be remedied with all reasonable dispatch. The term "force majeure" as employed herein

means an occurrence not within the reasonable control of the party claiming force majeure and which by the exercise of due diligence such party is unable to prevent or overcome, and, subject to the exercise of due diligence to prevent or overcome, such occurrence shall include, without limiting the foregoing, acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests, and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, the necessity for making repairs to or alterations of machinery or lines of pipe, freezing of wells or lines of pipe, partial or entire failure of wells or sources of supply of gas, any act or omission by parties not controlled by the party having the difficulty. Such terms shall likewise include (a) in those instances where either party hereto is required to obtain servitudes, rights of way grants, permits or licenses to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such servitudes, rights of way grants, permits or licenses, and (b) in those instances where either party hereto is required to furnish materials and supplies for the purpose of constructing or maintaining facilities or is required to secure permits or permission from any governmental agency to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such materials and supplies, permits and permissions. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty, and that the above requirement that any force majeure shall be remedied with all reasonable

dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of opposing party when such course is inadvisable in the discretion of the party having the difficulty.

IV. WARRANTY

4.1 Seller hereby warrants that it has the right to sell all gas delivered by Seller to Buyer under the Agreement to which this exhibit is attached, and that it is free from liens and adverse claims. Subject to Article V of said Agreement, Seller agrees to pay or cause to be paid all taxes and assessments levied on the gas prior to its delivery to Buyer, and to pay or cause to be paid to the parties entitled thereto all royalties, overriding royalties and like charges against said gas or the value thereof.

V. REGULATORY BODIES

5.1 This Agreement is subject to all valid orders, rules, and regulations of any regulatory body having jurisdiction. In the event any provision of this Agreement shall violate any applicable Federal or State law or valid applicable rule or regulation of Federal or State regulatory bodies having jurisdiction, then such provision shall be of no force and effect so long, and only so long, as it is in violation thereof, but the remainder of the Agreement shall be valid and effective as though such provision or provisions had not been included herein, provided, however, that if the deletion of the provision which is no longer to be of force and effect renders the remaining provisions meaningless or impossible of performance by either party, this agreement shall be of no force or effect for so long as the foregoing provision is in violation of such law, rule or regulation.

VI. RECEIPT OF GAS

6.1 Seller shall not be required to dispatch specific quantities of gas for delivery to Buyer, but Buyer shall receive gas it requires within the quantity limitations set forth in Article VI of the Agreement to which this Exhibit is annexed. Nonetheless, Buyer shall from time to time advise Seller of its anticipated requirements in order to permit Seller to properly regulate the flow of gas through its Kenai-Nikiski pipeline to meet the deliveries hereunder as well as Seller's other requirements for gas through said pipeline.

AGO 570498

Contract and all amendments to APC and ANG/AGAS Sales agreements



ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

August 27, 1973

Alaska Gas and Service Company
Post Office Box 6288
Anchorage, Alaska 99502

Gentlemen:

This letter pertains to the Gas Sale Contract dated December 9, 1960, as heretofore amended October 16, 1962, October 15, 1963, April 1, 1970, and October 3, 1972 together with letters of understanding of interpretation dated September 30, 1968, November 4, 1968, and April 27, 1970, between Alaska Pipeline Company, as Seller, and Alaska Gas and Service Company (formerly Anchorage Natural Gas Corporation) as Buyer.

missing

Both Buyer and Seller now agree to further amend said contract by specifying that to the price otherwise payable for gas delivered by Seller to Buyer, the amount of 2¢ per MCF shall be added on all deliveries commencing January 1, 1974, to reimburse "additional costs of gas" resulting from renegotiation of Seller's Gas Purchase Contract with Seller's suppliers (producers), such increase having been anticipated in the Gas Sale Contract of December 9, 1960, in paragraph 2 of Article V.

Please execute six copies of this amendment and return five copies, to indicate your agreement with this amendment.

Very truly yours,

Raymond J. Reeves
General, USAF (Ret.)
President

RECEIVED AS
Accepted this 31st day of August, 1973
For: Alaska Gas and Service Company
31 JAN 74

By: _____
Dale Tool, President

AGO 570499

ALASKA PIPELINE COMPANY

P. O. BOX 6288
ANCHORAGE, ALASKA 99502

3000 SPENARD ROAD
PHONE (907) 277-5551

October 3, 1972

Alaska Gas and Service Company
Post Office Box 6288
Anchorage, Alaska 99502

Gentlemen:

This letter pertains to the Gas Sale Contract dated December 9, 1960, as heretofore amended October 16, 1962, October 15, 1963 and April 1, 1970, together with letters of understanding of interpretation dated September 30, 1968, November 4, 1968 and April 27, 1970, between Alaska Pipeline Company, as Seller, and Alaska Gas and Service Company (formerly Anchorage Natural Gas Corporation) as Buyer.

Both Buyer and Seller now agree to further amend said contract and substitute in lieu thereof the following:

Article IV - Term of Agreement

To substitute the words "Buyers' Certificate of Convenience and Necessity as issued by the Alaska Public Utilities Commission" in place of the words "Buyers' franchise to distribute gas in the City of Anchorage".

Article V - Price

To delete entirely from this Article Paragraph 1, the Demand Charge: $4.50 per MCF of monthly billing demand

Article VI - Determination of Billing Demand

This entire article, as previously amended, is to be deleted in its entirety.

Exhibit "A"

E. Statements and Payments

All reference to the "demand charge" shall be deleted, and substitute for the minimum billing following: "The minimum billing shall be the amount as calculated hereunder for all gas delivered hereunder for the preceding month".

AGO 570500

All other terms and provisions of said contract shall continue in full force and effect. The effective date of such amendment shall be January 1, 1971.

If the foregoing is agreeable to you, please execute all six copies of this amendment and return five copies thereof to the undersigned.

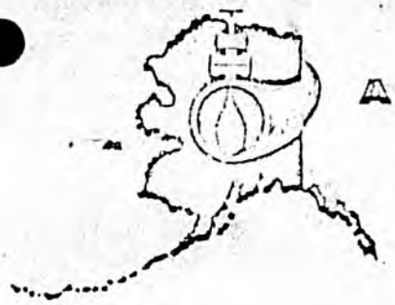
Very truly yours,

R. J. Reeves
General USAF (Ret.)
President

Accepted this 3rd day of October 1972

For: ALASKA GAS AND SERVICE COMPANY

By: _____
Dale Tool, President



ALASKA PIPELINE COMPANY

P. O. BOX 6554 • HOUSTON, TEXAS 77005

April 1, 1970

Anchorage Natural Gas Corporation
P. O. Box 6288
Anchorage, Alaska 99502

Gentlemen:

This letter pertains to the Gas Sales Contract dated December 9, 1960, as amended, between Alaska Pipeline Company, as Seller, and Anchorage Natural Gas Corporation, as Buyer.

It is in the interest of Seller to encourage sales of natural gas by Buyer during summer off-peak months and to encourage Buyer to enter into contracts for resale of gas purchased from Seller providing for interruption of deliveries during periods of peak demand. It is understood that Buyer has filed with the Alaska Public Service Commission Rate Schedules PI and PPI providing reduced rates for sales of natural gas for power generation during summer months subject to the purchaser of such gas for power generation providing and maintaining available at all times alternate fuel which will permit interruption of deliveries of natural gas to the purchaser by Buyer during peak periods with concomitant reductions in Buyer's requirements from Seller.

In consideration of the foregoing, Seller agrees to further amend the Gas Sales Contract as it pertains only to gas delivered to Buyer for resale to power generation customers on an interruptible basis by adding the following proviso under Subparagraph (c) of Paragraph 1 of Article V:

> "Provided that charges as otherwise computed under the above rate for power generation customers during the months of April through September shall be reduced by multiplying by 5 cents per Mcf the volume of gas delivered hereunder for resale by Buyer to public utilities which have agreed to purchase gas under Buyer's Rate Schedules PI or PPI and which have installed and maintained, ready for use, standby fuel and equipment to permit interruption of gas supply to such customer by Buyer on not less than 2 hours notice given by Seller to Buyer for not more than 10 days in any calendar month during October through March. Provided further that Buyer shall furnish Seller copies of Buyer's interruptible power plant service rate schedule as well as copies of any executed agreements for service between Buyer and its power customers who are purchasing gas from Buyer under its applicable interruptible power plant service rate schedule (s)."

AGO 570502

ALASKA PIPELINE COMPANY

P. O. BOX 6554 • HOUSTON, TEXAS 77005

If after the above rate offered herein by Seller to Buyer is accepted by Buyer the regulatory body under whose authority and jurisdiction Buyer's rates are controlled subsequently determines that Buyer's interruptible power plant service should not have gone into effect, then this amendment to the Gas Sales Contract shall be null and void.

All other terms and provisions of said Gas Sale Contract shall continue in full force and effect.

If the foregoing is agreeable to you, please execute all six copies of this letter agreement and return five executed copies thereof to the undersigned.

Very truly yours,

ALASKA PIPELINE COMPANY

Herman H. Bockstege, Jr.
Vice President

HHB:hf

ACCEPTED THIS 5 DAY OF June, 1970

BY _____
ANCHORAGE NATURAL GAS CORPORATION

AGO 570503

Feb Gas Purchases Contracts
ARGC



ALASKA PIPELINE COMPANY

P. O. BOX 1865 • ANCHORAGE, ALASKA

ARGC

October 15, 1963

Anchorage Natural Gas Corporation
P. O. Box 6288
Anchorage, Alaska

Gentlemen:

This letter pertains to the Gas Sale Contract dated December 9, 1960, as amended October 16, 1962, between Alaska Pipeline Company, as Seller, and Anchorage Natural Gas Corporation, as Buyer.

In view of the anticipated substantial growth in your gas sales for power generation, Seller agrees to further amend the rate in the Gas Sale Contract as it pertains to the gas delivered to Buyer for power generation customers only (Paragraph 1 of Article V, item (c), as amended), effective upon the filing by Buyer with Seller of a copy of Buyer's approved and filed revised Power Plant Service Rate Schedule, applicable to the anticipated increased power sales volumes, and upon the filing by Buyer with Seller of a copy of any executed Agreement for Service between Buyer and its power customers, upon which the substantial growth was predicated.

Subject to the above conditions, and as of the effective time thereof, the price to be paid by buyer to Seller for all gas delivered to Buyer for power generation sales only shall be changed by deleting from said Gas Sale Contract as amended Paragraph 1 of Article V and substituting in lieu thereof the following:

"1. Subject to the provisions of Paragraph 2 below, the price to be paid by Buyer to Seller for gas delivered to Buyer hereunder from October 15, 1963, shall be as follows:

Demand Charge: $4.50 per MCF of monthly billing demand

Commodity Charge: Gas delivered for:

(a) Firm customers - $.55 per MCF

(b) Interruptible customers - $.55 per MCF

(c) Power generation customers:

From 1 MCF to 100,000 MCF/year - all MCF @ $.52 per MCF
From 100,001 MCF to 295,000 MCF/year - all MCF @ $.48 per MCF
From 295,001 MCF to 650,000 MCF/year - all MCF @ $.44 per MCF
From 650,001 MCF to 950,000 MCF/year - all MCF @ $.40 per MCF
From 950,001 MCF to 1,550,000 MCF/year - all MCF @ $.35 per MCF
Excess of 1,550,000 MCF/year - all MCF @ $.34 per MCF

AGO 570504

ALASKA PIPELINE COMPANY

ANCHORAGE, ALASKA

Buyer shall notify Seller in writing by December 1 of each year the estimated volume of gas to be delivered by Seller to Buyer for power generation customers for the following year. The volume so estimated will determine the appropriate rate as listed above at which Seller will charge Buyer for gas delivered to Buyer for power generation customers for the ensuing year. Buyer may not reduce the estimated volume during a year or reduce the volume by more than two (2) consecutive blocks of the rate below that estimated for the preceding year, except at the option of Seller."

All other terms and provisions of said Gas Sale Contract shall continue in full force and effect.

If the foregoing is agreeable to you, please execute all six copies of this letter agreement and return five executed copies thereof to the undersigned.

Very truly yours,

ALASKA PIPELINE COMPANY

Robert B. Baldwin
President

Accepted and agreed to this 23 day of October, 1963:

ANCHORAGE NATURAL GAS CORPORATION

By _____
Vice President

AGO 570505

Mrs. Jo Sale Contr



ALASKA PIPELINE COMPANY

P. O. BOX 6554 • HOUSTON 5, TEXAS

October 16, 1962

Anchorage Natural Gas Corporation
P. O. Box 6288
Anchorage, Alaska

Gentlemen:

This letter pertains to the Gas Sales Contract dated December 9, 1960 between Alaska Pipeline Company, as Seller, and Anchorage Natural Gas Corporation, as Buyer.

Both Buyer and Seller now agree to delete from said Contract Paragraph 1 of Article V and substitute in lieu thereof the following:

"1. Subject to the provisions of Paragraph 2 below, the price to be paid by Buyer to Seller for gas delivered to Buyer hereunder from September 1, 1962 shall be as follows:

Demand Charge: $4.50 per Mcf of monthly billing demand

Commodity Charge:
gas delivered for:
(a) Firm customers $.55 per Mcf
(b) Interruptible customers $.55 per Mcf"
(c) Power generation customers $.44 per Mcf"

Both Buyer and Seller now agree to delete from said Contract Paragraph 1 and 2 of Article VI and substitute in lieu thereof the following:

"1. Buyer shall from time to time by notice in writing to Seller furnish to Seller the names of all customers to whom Buyer is then selling interruptible gas, and the names of all customers to whom Buyer is selling gas for the purpose of electric utility power generation. Buyer shall meter daily the consumption of such gas by each such customer or estimate the daily consumption of such gas by each customer in determining the total thereof to be deducted from the total quantity of gas delivered by Seller to Buyer hereunder on such day. The remaining quantity (herein called "Demand Gas") shall be used for the purpose of determining the billing demand. The Seller may require the daily metering of all interruptible and electric utility power generation customers at any time by the giving of reasonable advance notice to Buyer in writing.

2. During the development period prior to August 1, 1962, the billing demand for any month, and for each day in such month,

AGO 570506

shall be the greatest quantity of Demand Gas theretofore delivered by Seller to Buyer on any day during such development period; however in no event shall the average price paid for all gas delivered hereunder during this period fall below 65¢/Mcf per month. After such date, the billing demand for any month, and for each day in such month, shall be the greater of:

(a) The greatest quantity of Demand Gas delivered by Seller to Buyer hereunder on any day during the 12 months ending with such month

or

(b) Ninety per cent (90%) of the greatest previous billing demand."

Both Buyer and Seller now agree to delete from said Contract Article VII and substitute in lieu thereof the following:

"ARTICLE VII - Addresses

Until Buyer is otherwise notified in writing by Seller, the address of Seller is and shall remain as follows:

Alaska Pipeline Company
P. O. Box 1855
Anchorage, Alaska

and unless Seller is otherwise notified in writing by Buyer, the address of Buyer is and shall remain as follows:

Anchorage Natural Gas Corporation
P. O. Box 6288
Anchorage, Alaska

All notices required to be given in writing hereunder shall be given to the respective parties at such addresses or such other addresses as the parties shall designate by written notice to the other."

All other terms and provisions of said Contract shall continue in full force and effect.

If the foregoing is agreeable to you, please execute all six copies of this letter agreement and return five executed copies thereof to the undersigned.

Very truly yours,

ALASKA PIPELINE COMPANY

By: _____
President

Accepted and agreed to
this 31st day of October, 1962

ANCHORAGE NATURAL GAS CORPORATION

By: _____
Vice President

AGO 570507

signed

GAS SALE CONTRACT

THIS AGREEMENT, entered into this 9th day of December, A.D., 1960, by and between ALASKA PIPELINE COMPANY, a corporation organized under the laws of the State of Alaska (herein called "Seller"), and ANCHORAGE NATURAL GAS CORPORATION, a corporation organized under the laws of the State of Alaska (herein called "Buyer"),

WITNESSETH:

In consideration of the premises and of the mutual covenants and agreements herein contained, Seller and Buyer do covenant and agree as follows:

ARTICLE I - Definitions

Except where the context otherwise indicates another or different meaning or intent, the following terms are intended and used and shall be construed to have meanings as follows:

1. The term "day" shall mean a period of twenty-four (24) consecutive hours beginning and ending at 8:00 o'clock A.M. Alaska Standard Time.

2. The term "month" shall mean the period beginning at 8:00 o'clock A M. Alaska Standard Time on the first day of a calendar month and ending at 8:00 o'clock A.M. Alaska Standard Time on the first day of the succeeding calendar month.

3. The term "year" shall mean a period of 365 days commencing with the day of first delivery of gas hereunder and each 365 days thereafter, except that in a year having a date of February 29th, such year shall consist of 366 days.

4. The term "cubic foot of gas" shall mean the amount of gas required to fill a cubic foot of space when the gas is at an absolute pressure of fourteen and sixty-five hundredths (14.65)

pounds per square inch and at a temperature of sixty (60) degrees Fahrenheit.

5. The term "MCF" shall mean one thousand (1,000) cubic feet of gas.

6. The term "British thermal unit" (BTU) is defined as the amount of heat required to raise the temperature of one (1) pound of water from fifty-nine (59) degrees Fahrenheit to sixty (60) degrees Fahrenheit at a pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch absolute.

7. The term "Buyer's Maximum Daily Firm Load Requirements" shall mean the maximum quantity of gas that Buyer is required to deliver during any day in a twelve (12) month period commencing the first day of August to all purchasers to whom Buyer is obligated to deliver gas without any right to interrupt such deliveries at any time, herein called "firm gas."

8. The term "Buyer's Demand Obligation" shall mean all of Buyer's Maximum Daily Firm Load Requirements other than the quantity of gas required to be delivered to a purchaser for use in the generation of electricity to be sold as a utility.

9. The term "Buyer's Maximum Daily Interruptible Load Requirements" shall mean the maximum quantity of gas that Buyer is required to deliver during any one day in a twelve (12) month period commencing the first day of August to all purchasers to whom Buyer is obligated to deliver gas, subject only to the right of Buyer to interrupt such deliveries during any period that Buyer does not have any gas for delivery due to its firm load requirements, herein called "interruptible gas."

ARTICLE II - Quantities

AGO 570509

1. Subject to the provisions of this Agreement, and the general terms and conditions set forth in Exhibit "A" attached hereto and made a part hereof, Buyer agrees to purchase and receive from Seller, and Seller agrees to sell and deliver to Buyer, Buyer's requirements during the term of this Agreement, as determined in the manner provided for herein, of natural

gas for resale and use in Buyer's gas distribution business in the City of Anchorage, Alaska, and other areas to be supplied by Buyer. Prior to November 1, 1960, Seller and Buyer will mutually agree upon Buyer's estimated gas requirements during the term of this Agreement; and periodically thereafter, at such times as deemed appropriate by the parties, a redetermination of Buyer's gas requirements shall be made by mutual agreement of the parties. In the event that any such redetermination increases Buyer's gas requirements over the then existing determination thereof, Seller agrees to commit to Buyer under this Agreement Buyer's additional gas requirements in excess of the quantity of gas previously committed to Buyer hereunder to the extent that Seller has available such additional quantities of gas uncommitted to other uses or contracts and has sufficient capacity in its pipeline facilities to make delivery thereof to Buyer. In the event that any such redetermination establishes that Buyer's gas requirements during the remainder of the term of this Agreement shall be less than the then existing determination thereof, Buyer agrees to release Seller from its previous commitment to deliver such quantity of gas in excess of Buyer's gas requirements as established by such redetermination. If Seller does not have sufficient uncommitted quantities of gas available to deliver Buyer's entire gas requirements established by any such redetermination of Buyer's gas requirements, Buyer shall have the right to contract with others for the purchase of such quantities of gas required to satisfy its requirements in excess of the quantities which Seller has then committed to this Agreement.

2. On or before August 1, 1960, with respect to the period prior to the first day of August, 1961, and thereafter, on or before the first day of July of each year during the term hereof, Buyer shall notify Seller of Buyer's Maximum Daily Firm Load Requirements, Buyer's Demand Obligation, and Buyer's Maximum Interruptible Load Requirements during the twelve (12) month period beginning the first day of August of the following year,

furnishing Seller with evidence satisfactory to Seller of such requirements. Seller shall then notify Buyer on or before the first day of November following receipt of such notice of one of the following

(i) Seller has a sufficient quantity of natural gas and capacity in its transmission system and obligates itself to deliver hereunder Buyer's Maximum Daily Firm Load Requirements; or

(ii) Seller does not have a sufficient supply of natural gas or does not have capacity in its transmission system to deliver the entire Buyer's Maximum Daily Firm Load Requirements, and specifying the maximum firm load requirements that Seller can deliver; or

(iii) Seller does not have sufficient quantity of natural gas or does not have capacity in its transmission system to deliver the entire Buyer's Maximum Daily Firm Load Requirements, specifying the maximum firm load requirements that Seller can provide and stating that Seller will attempt to provide such required quantity and capacity on or before the first day of October next succeeding the date of such notice.

In the event Seller gives Buyer the notice called for in subparagraph (ii) or subparagraph (iii), then Buyer shall be free from the date of receipt of such notice from Seller that subparagraph (ii) applies, or from the first day of April in the event subparagraph (iii) applies and Seller has not notified Buyer by such date that it will deliver the entire Buyer's Maximum Daily Firm Load Requirements, to contract with others for the purchase of gas in excess of the maximum firm load requirements which Seller specifies that it is able to furnish hereunder.

3. Seller shall, to the best of its ability, operate its pipeline system in such manner that it shall be capable of delivering to Buyer aggregate quantities of gas equal on each day to Buyer's requirements on such day. Seller shall not, however, be obligated to deliver to Buyer gas in excess of Buyer's Maximum Daily Firm Load Requirements then in effect except to the extent that Seller elects to make such gas available; provided, however, that insofar as it is able to do so, Seller shall furnish Buyer one (1) day's notice whenever

and to the extent that curtailment or interruption of delivery of interruptible gas is necessary. Seller shall not be obligated hereunder to deliver in any one (1) hour more than seven per cent (7%) of Buyer's Maximum Daily Firm Load Requirement then in effect; but to the extent that in Seller's sole judgment it can do so, Seller will make hourly deliveries to Buyer without regard to such limitation.

ARTICLE III - Point of Delivery

1. The point of delivery of all gas delivered hereunder shall be at a point to be mutually agreed upon by the parties hereto and which shall be called the city gate of the City of Anchorage, Alaska, and at such other points as may be mutually agreed upon.

2. Seller shall be in control and possession of the gas deliverable hereunder and shall indemnify and hold Buyer harmless from any damage or injury caused thereby until the same shall have been delivered to Buyer, after which delivery Buyer shall be deemed to be in exclusive control and possession thereof and shall indemnify and hold Seller harmless from any injury or damage caused thereby.

ARTICLE IV - Term of Agreement

This Agreement shall be effective as of the date hereof and shall continue in effect for twenty (20) years from the date of the first delivery of gas hereunder, or for the full term of Buyer's franchise to distribute gas in the City of Anchorage, whichever is the longer period, and thereafter from year to year unless and until terminated either by Buyer or by Seller upon twelve (12) months' prior written notice to the other specifying a termination date.

ARTICLE V - Price

1. Subject to the provisions of Paragraph 2 below, the price to be paid by Buyer to Seller for gas delivered to Buyer hereunder shall be as follows:

Commodity Charge for All Gas Delivered: - $ .55 per MCF

Demand Charge: - $4.50 per MCF of monthly billing demand

} changed 10/18/62

2. Any increase in the cost of gas to Seller under its contracts with the producers thereof due to periodic price escalations, or otherwise, in addition to or greater than those in effect on the date of initial delivery of gas hereunder are hereinafter referred to as "additional costs of gas". Any sales, transactions, occupation, service, production, severance, gathering, transmission, export or excise tax, assessment or fee levied, assessed or fixed by the United States or any state or other governmental authority and taxes of a similar nature or equivalent in effect (not including income, excess profits, capital stock, franchise or general property taxes), in addition to or greater than those, if any, being levied, assessed or fixed on the date of execution hereof, in respect of or applicable to the natural gas to be delivered by Seller to Buyer hereunder and which Seller may be liable for, or is otherwise obligated to bear during any month, either directly or indirectly through any obligation to reimburse others, are hereinafter collectively referred to as "additional tax." It is expressly understood and agreed between the parties that so long as the additional cost of gas or additional tax shall be in effect, Buyer shall reimburse Seller for Buyer's proportionate share of such additional cost of gas and additional tax. In the event all or any part of such liability of seller is not determined or not determinable by the end of any month, then such additional amount required in respect of such liability not determined or determinable shall be set forth for all such months in any calendar year in a statement to be rendered by Seller to Buyer by April 1 of the following year, and Buyer shall pay the amount due pursuant to such statement on or before May 1 of such following year.

ARTICLE VI – Determination of Billing Demand

1. Buyer shall from time to time by notice in writing to Seller furnish to Seller the names of all customers to whom Buyer is then selling interruptible gas, and the names of all customers to whom Buyer is selling gas for the purpose of electric utility power generation. Buyer shall meter daily the consumption of such gas by each such named customer, and the total thereof shall be deducted from the total quantity of gas delivered by Seller to Buyer hereunder on such day. The remaining quantity (herein called "Demand Gas") shall be used for the purpose of determining the billing demand. Amended 10/16/62

2. During the development period prior to August 1, 1962, the billing demand for any month, and for each day in such month, shall be the greatest quantity of Demand Gas theretofore delivered by Seller to Buyer on any day during such development period. After such date, the billing demand for any month, and for each day in such month, shall be the greater of: Amended 10/16/62

(a) The greatest quantity of Demand Gas delivered by Seller to Buyer hereunder on any day during the 12 months ending with such month, or Buyer's Demand Obligation established as provided in Paragraph 3 of Article II hereof, whichever is the greater,

OR

(b) Ninety per cent (90%) of the greatest previous billing demand.

3. If on any day Buyer takes interruptible gas from Seller in violation of any notice of curtailment or interruption of interruptible gas given by Seller to Buyer, the quantity of gas so taken shall be added to the firm gas delivered on such day for the purpose of deter-

mining the billing demand.

4. If on one or more days in a month Seller is unable to deliver to Buyer a quantity of natural gas equal to the then billing demand, then, in respect of each such day, the demand charge for such month shall be reduced by the number of MCF which Seller was so unable to deliver multiplied by one thirtieth (1/30th) of $4.50; provided that nothing in this paragraph shall in any way diminish the obligation of Seller to deliver on such day or days natural gas up to Buyer's Maximum Daily Firm Load Requirements then in effect. If on one or more days in a billing month Buyer is unable, by reason of force majeure as hereinafter defined, to take delivery of any natural gas whatsoever from Seller, then, in respect of each such day, the demand charge for such month shall be reduced by the then billing demand in MCF multiplied by one thirtieth (1/30th) of $4.50.

ARTICLE VII - Addresses

Until Buyer is otherwise notified in writing by Seller, the address of Seller is and shall remain as follows:

Alaska Pipeline Company
P. O. Box 7011
Anchorage, Alaska

and unless Seller is otherwise notifed in writing by Buyer, the address of buyer is and shall remain as follows:

Anchorage Natural Gas Corporation
3000 Spenard Road
Spenard, Alaska

All notices required to be given in writing hereunder shall be given to the respective parties at such addresses or such other addresses as the parties shall designate by written notice to the other.

ARTICLE VIII - Miscellaneous

1. No waiver by either party hereto of any one or more defaults by the other in the performance of any provisions of this Agreement shall operate or be construed as a waiver of any future default or defaults, whether of like or different character.

2. This Agreement shall be binding upon and inure to the benefit of the successors and assigns of the respective parties hereto.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement by their duly authorized officers on the date first above set forth.

ATTEST:

H. Earl Lamb Jr.
Secretary

ALASKA PIPELINE COMPANY

By: _____
SELLER

ATTEST:

William C. Smith Jr.
Asst Secretary

ANCHORAGE NATURAL GAS CORPORATION

By: Horace B Webb
BUYER

AGO 570516

EXHIBIT "A"

(Attached to and incorporated in Gas Sale Contract between Alaska Pipeline Company, hereinafter referred to as "Seller", and Anchorage Natural Gas Corporation, hereinafter referred to as "Buyer.")

GENERAL TERMS AND CONDITIONS

A. - Measuring Station

1. Seller shall install, maintain and operate, at Seller's own expense, at or near the point of delivery, a measuring station properly equipped with orifice meters, flange connections, orifice plates and other necessary equipment by which the volume of gas delivered hereunder shall be measured. Volumes shall be computed and orifice meters shall be installed, maintained and operated as prescribed by the American Gas Association in Gas Measurement Committee Report Number 3, including the appendix thereto, as published April, 1955, and any subsequent amendments, additions or changes thereto as may be made from time to time by the A.G.A. Gas Measurement Committee. Buyer shall have access to such metering equipment at reasonable hours, but the reading, calibrating and adjusting thereof and the changing of charts shall be done only by Seller.

2. Buyer may install, maintain and operate, at its own expense such pressure regulators and check measuring equipment as it shall desire, so installed as not to interfere with the operation of Seller's measuring equipment. Seller shall have access to such check measuring equipment at reasonable hours, but the reading, calibrating and adjusting thereof and the changing of charts shall be done only by Buyer.

3. Each party shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating or adjusting done in

connection with the other's measuring equipment used in measuring deliveries hereunder. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its record and charts, together with calculations therefrom, for inspection and verification, subject to return within ten (10) days after receipt thereof.

4. In the event a meter is out of service, or registering inaccurately, the volume of gas delivered hereunder shall be estimated:

(a) By using the registration of any check meter or meters if installed and accurately registering, or in the absence of (a);

(b) By correcting the error if the percentage of error is ascertainable by calibration, test or mathematical calculation or, in the absence of both (a) and (b), then;

(c) By estimating the quantity of delivery by deliveries during periods under similar conditions when the meter was registering accurately.

5. At least once each month Seller shall verify the accuracy of Seller's measuring equipment and Buyer shall verify the accuracy of its check measuring equipment. If either party shall notify the other that it desires a special test of any measuring equipment, the parties shall cooperate to secure a prompt verification of the accuracy of such equipment. If either party at any time observes a variation between the delivery meter and the check meter, it will promptly notify the other party thereof and both parties will then cooperate to secure an immediate verification of the accuracy of such equipment. Each party shall give to the other notice of the time of all tests of meters reasonably in advance of the holding of such tests in order that the other party may conveniently have its representative present.

6. If, upon test, any measuring equipment is found to be in error not more than two per cent (2%), previous records of such equipment shall be considered accurate in computing deliveries hereunder; but such equipment shall be adjusted at once to record correctly. If, upon

test, any measuring equipment shall be found to be inaccurate by an amount exceeding two per cent (2%), at a recording corresponding to the average hourly rate of flow for the period since the last preceding test, then any previous recordings of such equipment shall be corrected for any period which is known definitely or agreed upon, but in case the period is not known definitely or agreed upon such correction shall be for a period extending over one half of the time elapsed since the date of last test, not exceeding a correction period of sixteen (16) days.

7. Each party shall preserve for a period of at least two (2) years all test data, charts and other similar records.

B. - Measurements

1. The sales unit of the gas deliverable hereunder shall be one (1) MCF of gas.

2. The volume of the gas delivered hereunder shall be determined as follows:

(a) The unit of volume for the purpose of measurement shall be one cubic foot of gas at a base temperature of sixty (60) degrees Fahrenheit and at a pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch absolute with correction for deviation from Boyle's Law. Computation of volumes shall be in accordance with applicable rules, regulations and orders promulgated by a recognized regulatory body.

(b) The average absolute atmospheric pressure shall be assumed to be fourteen and seven-tenths (14.7) pounds to the square inch, irrespective of actual elevation or location of the point of delivery above sea level or variations in such atmospheric pressure from time to time.

(c) The deviation of the gas from Boyle's Law at the pressures, temperatures and specific gravities under which the gas is delivered hereunder, shall be read from the A.G.A. convenient operating tables of "Supercompressibility Factors for Natural Gas," without adjustment

of diluents, which have been developed from the basic tables contained in the A.G.A. Gas Measurement Committee Report Number 3.

(d) The temperature of the gas passing the meters shall be determined by the continuous use of a recording thermometer so installed by Seller that it may properly record the temperature of the gas flowing through the meters. The arithmetical average of the hourly temperature readings recorded each twenty-four (24) hour day shall be used in computing gas volumes for that date.

(e) Unless the parties hereto agree to the use of a spot test method, the specific gravity of the gas delivered hereunder shall be determined by the continuous use of an Acme recording gravitometer, or other standard gravitometer agreed upon by the parties hereto, so installed that it may properly record the specific gravity of the gas flowing through the meters. The arithmetical average of the specific gravity recorded during each twenty-four (24) hour day shall be used in computing gas volumes for that date. If the parties hereto agree to the use of a spot test method, such spot test shall be made with an Edwards type of gas balance, or by such other method as shall be agreed upon between the parties. If the spot test method is used, the specific gravity of the gas delivered hereunder shall be determined once monthly, or as much oftener as is found necessary in practice. The regular monthly test shall determine the specific gravity to be used in computation for the measurement of natural gas delivered, until the end of such month or until changed by special test, the special test to be applicable from the day made through the remaining days in such month.

C. - Delivery Pressure

The gas delivered to Buyer at the point of delivery shall be delivered within such range required for accurate metering as shall, from time to time, exist under operating conditions of the pipeline system of Seller, but in any event at a pressure not less than one

hundred twenty-five (125) pounds per square inch guage. Buyer shall install, maintain and operate at its own expense such pressure regulating equipment as may be necessary to regulate the pressure of gas after it is delivered to Buyer.

D. - Quality of Gas

1. Seller agrees that:

(a) The gas delivered hereunder shall have a total heating value of not less than nine hundred and fifty (950) British thermal units per cubic foot. If at any time Seller shall become unable to deliver gas possessing at least such total heating value, Buyer shall have the option from time to time to refuse to accept that part of Seller's gas which is so deficient so long as said heating value remains below nine hundred and fifty (950) British thermal units per cubic foot. In the event Buyer accepts delivery of said gas when the heating value thereof is below nine hundred and fifty (950) British thermal units per cubic foot, Buyer may reduce the total amount payable as the purchase price for gas delivered under this contract for each month during which such deficiency obtains by an amount determined by multiplying such total amount by a fraction having as its numerator the average deficiency of British thermal units per cubic foot of gas below nine hundred and fifty (950) and its denominator nine hundred and fifty (950).

(b) Buyer shall have the right to determine, at such time or times as it may desire, the total heating value of the gas in British thermal units per cubic foot by means of some approved method of general use in the industry. Buyer shall give to Seller notice of the time of all tests for determining the British thermal unit content of the gas to be conducted by such party reasonably in advance of making the test in order that the other party may conveniently have its representative present. Should there be any material variance between tests by Buyer and Seller, a joint test will be run and will be controlling, effective from the first day of the calen-

dar month preceding such joint test. The British thermal unit content per cubic foot shall be determined for a cubic foot of gas at a temperature of sixty (60) degrees Fahrenheit when saturated with water vapor and at an absolute pressure equivalent to thirty inches (30") of mercury at thirty-two degrees (32°) Fahrenheit when the products of combustion are cooled to the initial temperature of gas and air and when the water formed by combustion is condensed to the liquid state.

2. Seller agrees that the gas delivered hereunder:

(a) Shall not contain more than one (1) grain of hydrogen sulphide per one hundred (100) cubic feet of gas as determined by the Tutwiler test or some other quantitative test, mutually agreeable to the parties hereto, after the presence of hydrogen sulphide has been indicated by qualitative test.

(b) Shall not contain more than twenty (20) grains of total sulphur per one hundred (100) cubic feet of gas.

(c) Shall not contain in excess of:

(i) Three per cent (3%) by volume of carbon dioxide;

(ii) One per cent (1%) by volume of oxygen;

(iii) Five (5) pounds of water vapor per one million (1,000,000) cubic feet of gas when measured at a pressure of fourteen and sixty-five hundredths (14.65) pounds per square inch absolute and a temperature of sixty (60) degrees Fahrenheit.

(d) Shall have a temperature of not more than one hundred twenty degrees (120°) Fahrenheit.

3. In addition to meeting the above specifications, the gas delivered hereunder shall be commercially free from dust, gums, gum forming constituents or other liquid or solid matter which might become separated from the gas in the course

of transportation through pipelines.

E. - Statements and Payments

1. On or before the tenth (10th) day of each calendar month after deliveries of gas are commenced hereunder, Seller shall render a statement to Buyer showing the amount of gas delivered hereunder during the last preceding calendar month and the demand charge applicable to such month. Buyer agrees to make payment to Seller on or before the twentieth (20th) day of each calendar month for all gas delivered, and for the demand charge, due hereunder for the preceding month. The minimum billing shall consist of the Demand Charge.

2. Each party shall have the right at reasonable times to examine the books, records and charts of the other party to the extent necessary to verify the accuracy of any statement, charge or computation made pursuant to the provisions of any Article hereof. If any such examination reveals any inaccuracy in such billing theretofore made, the necessary adjustment in such billing and payments shall be promptly made; provided that no adjustment for any billing or payment shall be made after the lapse of one (1) year from the rendition thereof.

F. - Force Majeure

1. In the event of either party hereto being rendered unable, wholly or in part, by force majeure to carry out its obligations under this Agreement, other than to make payments theretofore accrued hereunder, it is agreed that on such party giving notice and full particulars of such force majeure in writing or by telegraph to the other party as soon as possible after the occurrence of the cause relied on, then the obligations of the party giving such notice, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused but for no longer period, and such cause shall as far as possible be remedied with all reasonable dispatch. The term "force majeure"

as employed herein means an occurrence not within the control of the party claiming force majeure and which by the exercise of due diligence such party is unable to prevent or overcome, and, subject to the exercise of due diligence to prevent or overcome, such occurrence shall include acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, the necessity for making repairs to or alterations of machinery or lines of pipe, freezing of wells or lines of pipe, partial or entire failure of wells or sources of supply of gas, any act or omission by parties not controlled by the party having the difficulty, any act or omission (including failure to take gas) of a purchaser of gas from Buyer which is excused by any event or occurrence of the character herein defined as constituting force majeure, and any other causes, whether of the kind herein enumerated or otherwise, not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome; such term shall likewise include (a) in those instances where either party hereto is required to obtain servitudes, rights of way grants, permits, franchises or licenses to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such servitudes, rights of way grants, permits, franchises or licenses, and (b) in those instances where either party hereto is required to furnish materials and supplies for the purpose of constructing or maintaining facilities or is required to secure permits or permission from any governmental agency to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable

diligence, such materials and supplies, permits and permissions. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty, and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of opposing party when such course is inadvisable in the discretion of the party having the difficulty.

G. - Warranty of Title

Seller hereby warrants the title to all gas delivered by Seller to Buyer under this Agreement, the right to sell the same and that it is free from all liens and adverse claims, and agrees, if notified thereof by Buyer, to indemnify Buyer against all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of any adverse legal claims of any and all persons to or against said gas. In the event any adverse claim of any character whatsoever is asserted in respect to any of said gas, Buyer may retain the purchase price thereof up to the amount of such claim without interest until such claim has been finally determined, as security for the performance of Seller's obligations with respect to such claim under this Section G, or until Seller shall have furnished bond to Buyer, in an amount and with sureties satisfactory to Buyer, conditioned for the protection of Buyer with respect to such claim.

AGO 570525

H. - Regulatory Bodies

This Agreement is subject to all present and future valid and applicable orders, rules and regulations of any municipal, Federal or State regulatory body having jurisdiction. In the event any provision of this Agreement shall violate any applicable Federal or State law or valid applicable rule or regulation of municipal, Federal or State regulatory bodies having jurisdiction, then such provision shall be of no force and effect so long, and only so long, as it is in violation thereof, but the remainder of the Agreement

shall be valid and effective as though such provision or provisions had not been included herein.

I. - Operation of Properties

Seller shall have agents or employees available at all times to receive Buyer's dispatchers' requests for changes in rates of delivery of gas hereunder as required by Buyer from time to time.

J. - Termination

If either party shall fail to perform any of the covenants or obligations imposed upon it under and by virtue of this Agreement, the other party may at its option terminate this Agreement by proceeding as follows: The other party shall cause a written notice to be served on the party in default stating specifically the cause for terminating this Agreement and declaring it to be the intention of the party giving the notice to terminate the same; thereupon the party in default shall have thirty (30) days after the service of the said notice in which to remedy or remove the cause or causes stated in the said notice, and if within said period of thirty (30) days the party in default does so remedy and remove said cause or causes and fully indemnifies the other party for any and all consequences of such breach, then such notice shall be withdrawn and this Agreement shall continue in full force and effect. In case the party in default does not so remedy and remove the cause or causes or does not indemnify the party giving the notice for any and all consequences of such breach within said period of thirty (30) days, then this Agreement shall become null and void from and after the expiration of such period. Any cancellation of this Agreement pursuant to the provisions of this section shall not exclude the right of either party to collect any amount then due it by the other party or exclude any rights or remedies either party may have against the other by reason of any default occurring before such termination.

STATE of ALASKA

MEMORANDUM

TO: Elke Kallab
Legislative Affairs Agency
Pouch Y
Juneau, Alaska 99811

DATE: May 17, 1977

FILE NO:

TELEPHONE NO:

FROM: APUC
J. Lowell Jensen

SUBJECT: Copies of Contract for the Military concerning Alaska Pipeline

Enclosed are copies of the contract for Ft. Richardson and Elmendorf AFB with Alaska Pipeline Company.

These contracts do not directly reference Union/Marathon but may be indicative of the gas costs to Alaska Pipeline Company.

Utility Service Contract 10/1/71

Utility Service Contract 4/14/7/?

ALASKA PUBLIC UTILITIES COMMISSION

J. Lowell Jensen
Executive Director

Quite useless
5/23/77

AGO 570527

UTILITY SERVICE CONTRACT

Department of the Army
Various Delivery Points at
Fort Richardson — Anchorage — — Alaska
Premises to be served — City — County — State

Contract Number DAFA03-72C0035

Alaska Pipeline Company — P.O. Box 6288, Anchorage, Alaska 99502
Contractor — Contractor's Address

Premises are: (X) Government owned
( ) Government leased
Name of lessor _____
Symbol number of lease _____

Estimated annual cost $25,000.00

Bills will be rendered to Finance & Accounting Officer

at P. O. Box 499, Ft Richardson, Alaska 99505

Connection charge $ None

Payments will be made by Finance & Accounting Officer

at P. O. Box 499, Ft Richardson, Alaska 99505

Appropriation Chargeable: 2122020 93-6600 P20-2330 S95-523 (20CJ41)

This contract is negotiated pursuant to 10 U.S.C. 2304(a)(10).

THIS CONTRACT is entered into as of 1971 (Year) October (Month) 1st (Day) by and between the UNITED STATES OF AMERICA, hereinafter called the Government, represented by the Contracting Officer executing this contract, and Alaska Pipeline Company

whose address is Post Office Box 6288, Anchorage, Alaska 99502,

hereinafter called the Contractor.

I. SCOPE. Subject to the terms and conditions hereinafter set forth, the Contractor shall furnish, and the Government shall purchase and receive, natural gas service (hereinafter called service) requested by the Government from the Contractor at the premises to be served hereunder (hereinafter called the service location), in accordance with the General and Technical Provisions and the natural gas service specifications attached hereto and made a part hereof.

(Basic contract continued on next page)

II. TERM. This contract shall continue in effect until terminated at the option of the Government by the giving of written notice not less than 90 days in advance of the effective date of termination.

IN WITNESS WHEREOF, the parties hereto have executed this contract as of the day and year first above written.

UNITED STATES OF AMERICA

ALASKA PIPELINE COMPANY
Name of Contractor

BY _____
Signature

BY _____
Signature of Contracting Officer and Date

DALE TEEL
Typed Name

SVEN E. ERIKSSON
Typed Name of Contracting Officer

Title Vice President & General Manager

APPROVED:

APPROVED:
EDMUND J. RYAN, DAC
POWER PROCUREMENT OFFICER'S REPRESENTATIVE
HEADQUARTERS, US ARMY, ALASKA

RECEIVED
JUL 24 1974
State of Alaska
Public Utilities Commission

SARAL Form 109
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AGO 570529

TECHNICAL AND GENERAL PROVISIONS FOR UTILITY SERVICE

I. TECHNICAL PROVISIONS

1. MEASUREMENT OF SERVICE.

(a) All service furnished by the Contractor shall be measured by metering equipment of standard manufacture, furnished, installed, maintained, calibrated, and ready by the contractor at his expense. When more than a single meter is installed at the service location, the readings thereof shall be billed conjunctively. In the event that any meter fails to register or registers incorrectly, the quantity of service delivered through it during that period shall be determined and an equitable adjustment based thereon shall be made in the Government's bills (for this purpose any meter which registers not more than two (2) percent slow or fast shall be deemed correct). Failure to agree on any adjustment shall be a dispute concerning a question of fact within the meaning of the "Disputes" clause of this contract.

(b) The Contractor shall read all meters at periodic intervals of approximately thirty (30) days. All billings based on meter readings of less than twenty-seven (27) days or more than thirty-two (32) days shall be prorated accordingly.

2. METER TEST.

The Contractor, at his expense, shall periodically inspect and test the meters installed by him, at intervals of no longer than one (1) year. At the written request of the Contracting Officer, the Contractor, in the presence of Government representatives, shall make additional tests of any or all meters. The cost of such additional tests shall be borne by the Government if the percentage of error is found to be not more than two (2) percent slow or fast. No meter shall be placed in service which on test registers in excess of one hundred (100) percent under normal operating conditions.

II. GENERAL PROVISIONS

1. PAYMENT.

(a) The Contractor shall be paid by the designated disbursing officer for service furnished hereunder at the rates specified; provided, that the Government shall be liable for the minimum monthly charge specified in this contract commencing with the billing period in which service is initially furnished and continuing until this contract is terminated, except that the minimum monthly charge shall be equitably prorated for the billing period in which commencement and termination of this contract shall become effective.

(b) Payments hereunder shall be contingent upon the availability of appropriations therefor, and shall not be made in advance of the service rendered.

(Provisions continued on next page)

(c) All bills for service shall be paid without penalty or interest and the Government shall be entitled to any discounts customarily applicable to payment of bills by all customers of the Contractor.

(d) Invoices for service rendered hereunder shall contain statements of the meter readings at the beginning of the billing period, meter constants, consumption during the billing period, and such other pertinent data as shall be required by the Government.

(e) The Contractor hereby declares that rates are not in excess of the lowest rates now available to any existing or prospective customer under like conditions of service, and agrees that during the life of this contract the Government shall continue to be billed at the lowest available rate for similar conditions of service.

2. RATES AND CHARGES.

For service furnished under this contract the Government shall pay the Contractor on the following schedule: Until otherwise selected by the Government at its option, Schedule 1-1(of Alaska Public Service Corporation, which is Contractor's wholly-owned gas distribution utility subsidiary) shall be applied to such service which can be interrupted by Contractor by giving of four hours' notice. For service which is not so interruptible, Schedule B or Schedule C shall be applied at the option of the Government to be exercised annually each year. If the Government at its option wishes to have deliveries at two or more delivery points combined for billing purposes (otherwise called "conjunctive billing"), said conjunctive billing shall be done by multiplying the minimum bill, for the Rate selected, by the number of such conjunctive billing delivery points. The designation of the Rate desired, or of conjunctive billing and the Rate therefor, may be made by the Government at any time provided that such designation shall continue in effect for one year without change and may thereupon be redesignated, each year.

3. PUBLIC REGULATION AND CHANGE OF RATES.

(a) Public Regulation. Service furnished under this contract shall be subject to regulation--in the manner and to the extent prescribed by law--by any Federal, state or local regulatory commission having jurisdiction. A copy of the Contractor's current existing rates (including changes) shall be furnished promptly to the Contracting Officer upon request.

(b) Change of Rates.

(i) If, during the term of this contract, the public regulatory commission having jurisdiction receives for filing in authorized manner any change in the rate schedule stipulated herein directly or by reference which result in higher or lower charges for service, the Contractor shall continue to furnish service as stipulated in this contract and the Government shall pay for service at the higher or lower charges from the effective date thereof, subject to judicial appeal.

(ii) In the event the Contractor, during the term of this contract, shall make effective any new or amended rate schedule, not incorporated herein directly or indirectly, applicable to any like condition of service furnished under this contract, which contains a lower rate or conditions

(Provisions continued on next page)

more favorable to the Government, the Contractor shall forward to the Contracting Officer a copy of the new or amended rate schedule within fifteen (15) days after the effective date thereof, and upon receipt of written request from the Government shall substitute the new or amended rate schedule for the rate schedule then in effect under this contract, commencing with the billing period in which the written request is received.

(iii) In the event of a permanent change in the class of service furnished the Government under this contract, service shall, effective sixty (60) days after written request is made by either party or at such other time as may be agreed upon, be furnished at the lowest available rate schedule of the contractor which is applicable to the class of service furnished following the permanent change.

(iv) The Contractor shall give the Contracting Officer written notice of the filing of an application for rate changes concurrently with the filing of an application. The notice shall fully describe the proposed rate change.

(v) In the event that the regulatory body promulgates any regulation not concerning rates which materially affects this contract, the Contractor shall immediately notify the Contracting Officer.

4. CHANGE IN VOLUME OR CHARACTER OF SERVICE.

The Contracting Officer shall give reasonable notice to the Contractor respecting any material changes anticipated in the volume or characteristics of the utility service required at each location.

5. CONTINUITY OF SERVICE AND CONSUMPTION.

(a) The Contractor shall use reasonable diligence to provide a regular and uninterrupted supply of service at the service location, but shall not be liable to the Government for damages, breach of contract, or otherwise, for failure, suspension, diminution, or other variations of service occasioned by any cause beyond the control and without the fault or negligence of the Contractor. Such causes may include, but are not restricted to, acts of God or of the public enemy, acts of the Government in either its sovereign or contractual capacity, fires, floods, epidemics, quarantine restrictions, strikes, or failure or breakdown of transmission or other facilities; provided, that when any failure, suspension, diminution, or variation of service shall aggregate more than one (1) hour during any billing period hereunder, an equitable adjustment shall be made in the monthly rates specified in this contract (including the minimum monthly charge).

(Provisions continued on next page)

(b) In the event the Government is unable to operate the service location in whole or in part for any cause beyond its control and without its fault or negligence, including but not limited to acts of God or of the public enemy, fires, floods, epidemics, quarantine restrictions, or strikes, an equitable adjustment shall be made in the monthly rates specified in this contract (including the minimum monthly charge) if the period during which the Government is unable to operate the service location in whole or in part shall exceed fifteen (15) days during any billing period hereunder.

6. CONTRACTOR'S FACILITIES.

(a) The Contractor, at his expense, shall furnish, install, operate, and maintain all facilities required to furnish service hereunder to, and to measure the service at, the point of delivery specified in the Utility Service Specifications. Title to all of these facilities shall remain in the Contractor and he shall be responsible for all loss of or damage to those facilities except that arising out of the fault or negligence of the Government, its agents or its employees. All taxes and other charges in connection therewith, together with all liability arising out of the negligence of the Contractor in the construction, operation, or maintenance of these facilities, shall be assumed by the Contractor.

(b) The Government hereby grants to the Contractor, free of any rental or similar charge, but subject to the limitations specified in this contract, a revocable permit to enter the service location for any proper purpose under this contract, including use of the site or sites agreed upon by the parties hereto for the installation, operation, and maintenance of the facilities of the Contractor required to be located upon Government premises. Authorized representatives of the Contractor will be allowed access to the facilities of the Contractor at suitable times to perform the obligations of the Contractor with respect to these facilities. It is expressly understood that the Government may limit or restrict the right of access herein granted in any manner considered to be necessary for the national security.

(c) The facilities shall be removed and Government premises restored to their original condition, ordinary wear and tear excepted, by the Contractor at his expense within a reasonable time after the Government shall revoke the permit herein granted and in any event within a reasonable time after termination of this contract, provided, that in the event of termination due to fault of the Contractor these facilities may be retained in place at the option of the Government until service comparable to that provided for hereunder is obtained elsewhere.

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7. CONFLICTS.

To the extent of any inconsistency between the provisions of this contract, and the provisions of any schedule, rider, or exhibit incorporated in this contract by reference or otherwise, the provisions of this contract shall control.

8. DEFINITIONS.

As used throughout this contract, the following terms shall have the meaning set forth below:

(a) The term "head of the agency" or "Secretary" means the Secretary, the Under Secretary, any Assistant Secretary, or any other head or assistant head of the executive or military department or other Federal agency; and the term "his duly authorized representative" means any person or persons or board (other than the Contracting Officer) authorized to act for the head of the agency or the Secretary.

(b) The term "Contracting Officer" means the person executing this contract on behalf of the Government, and any other officer or civilian employee who is a properly designated Contracting Officer; and the term includes, except as otherwise provided in this contract, the authorized representative of a Contracting Officer acting within the limits of his authority.

(c) Except as otherwise provided in this contract, the term "subcontracts" includes purchase orders under this contract.

9. ASSIGNMENT OF CLAIMS.

(a) Pursuant to the provisions of the Assignment of Claims Act of 1940, as amended (31 U.S.C. 203, 41 U.S.C. 15), if this contract provides for payments aggregating $1,000 or more, claims for moneys due or to become due the Contractor from the Government under this contract may be assigned to a bank, trust company, or other financing institution, including any Federal lending agency, and may thereafter be further assigned and reassigned to any such institution. Any such assignment or reassignment shall cover all amounts payable under this contract and not already paid, and shall not be made to more than one party, except that any such assignment or reassignment may be made to one party as agent or trustee for two or more parties participating in such financing. Unless otherwise provided in this contract, payments to an assignee of any moneys due or to become due under this contract shall not, to the extent provided in said Act, as amended, be subject to reduction or setoff. (The preceding sentence applies only if this contract is made in time of war or national emergency as defined in said Act and is with the Department of Defense, the General Services Administration, the

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Atomic Energy Commission, the National Aeronautics and Space Administration, the Federal Aviation Agency, or any other department or agency of the United States designated by the President pursuant to Clause 4 of the proviso of section 1 of the Assignment of Claims Act of 1940, as amended by the Act of May 15, 1951, 65 Stat. 41.)

(b) In no event shall copies of this contract or of any plans, specifications, or other similar documents relating to work under this contract, if marked "Top Secret," "Secret," or "Confidential," be furnished to any assignee of any claim arising under this contract or to any other person not entitled to receive the same. However, a copy of any part or all of this contract so marked may be furnished, or any information contained therein may be disclosed, to such assignee upon the prior written authorization of the Contracting Officer.

10. DISPUTES.

(a) Except as otherwise provided in this contract, any dispute concerning a question of fact arising under this conract which is not disposed of by agreement shall be decided by the Contracting Officer, who shall reduce his decision to writing and mail or otherwise furnish a copy thereof to the Contractor. The decision of the Contracting Officer shall be final and conclusive unless, within 30 days from the date of receipt of such copy, the Contractor mails or otherwise furnishes to the Contracting Officer a written appeal addressed to the Secretary. The decision of the Secretary or his duly authorized representative for the determination of such appeals shall be final and conclusive unless determined by a court of competent jurisdiction to have been fraudulent, or capricious, or arbitrary, or so grossly erroneous as necessarily to imply bad faith, or not supported by substantial evidence. In connection with any appeal proceeding under this clause, the Contractor shall be afforded an opportunity to be heard and to offer evidence in support of its appeal. Pending final decision of a dispute hereunder, the Contractor shall proceed diligently with the performance of the contract and in accordance with the Contracting Officer's decision.

(b) This "Disputes" clause does not preclude consideration of law questions in connection with decisions provided for in paragraph (a) above; provided, that nothing in this contract shall be construed as making final the decision of any administrative official, representative, or board on a question of law.

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Dale Seal
S.E. Eriksson

11. OFFICIALS NOT TO BENEFIT.

No member of or delegate to Congress, or resident Commissioner, shall be admitted to any share or part of this contract, or to any benefit that may arise therefrom; but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

12. COVENANT AGAINST CONTINGENT FEES.

The Contractor warrants that no person or selling agency has been employed or retained to solicit or secure this contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee, excepting bona fide employees or bona fide established commercial or selling agencies maintained by the Contractor for the purpose of securing business. For breach or violation of this warranty the Government shall have the right to annul this contract without liability or in its discretion to deduct from the contract price or consideration, or otherwise recover, the full amount of such commission, percentage, brokerage, or contingent fee.

13. EXAMINATION OF RECORDS.

(The following clause is applicable if the amount of this contract exceeds $2,500 and was entered into by means of negotiation, but is not applicable if this contract was entered into by means of formal advertising.)

(a) The Contractor agrees that the Comptroller General of the United States or any of his duly authorized representatives shall, until the expiration of three years after final payment under this contract, have access to and the right to examine any directly pertinent books, documents, papers, and records of the Contractor involving transactions related to this contract.

(b) The Contractor further agrees to include in all his subcontracts hereunder a provision to the effect that the subcontractor agrees that the Comptroller General of the United States or any of his duly authorized representatives shall, until the expiration of three years after final payment under the subcontract, have access to and the right to examine any directly pertinent books, documents, papers, and records of such subcontractor, involving transactions related to the subcontract. The term "subcontract" as used in this clause excludes (i) purchase orders not exceeding $2,500 and (ii) subcontracts or purchase orders for public utility services at rates established for uniform applicability to the general public.

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14. GRATUITIES.

(a) The Government may, by written notice to the Contractor, terminate the right of the Contractor to proceed under this contract if it is found, after notice and hearing, by the Secretary or his duly authorized representative, that gratuities (in the form of entertainment, gifts, or otherwise) were offered or given by the Contractor, or any agent or representative of the Contractor, to any officer or employee of the Government with a view toward securing a contract or securing favorable treatment with respect to the awarding or amending, or the making of any determinations with respect to the performing of such contract; provided, that the existence of the facts upon which the Secretary or his duly authorized representative makes such findings shall be in issue and may be reviewed in any competent court.

(b) In the event this contract is terminated as provided in paragraph (a) hereof, the Government shall be entitled (i) to pursue the same remedies against the Contractor as it could pursue in the event of a breach of the contract by the Contractor, and (ii) as a penalty in addition to any other damages to which it may be entitled by law, to exemplary damages in an amount (as determined by the Secretary or his duly authorized representative) which shall be not less than three nor more than ten times the costs incurred by the Contractor in providing any such gratuities to any such officer or employee.

(c) The rights and remedies of the Government provided in this clause shall not be exclusive and are in addition to any other rights and remedies provided by law or under this contract.

15. BUY AMERICAN ACT.

(a) In acquiring end products, the Buy American Act (41 U.S. Code 10 a-d) provides that the Government give preference to domestic source end products. For the purpose of this clause:

(i) "components" means those articles, materials, and supplies, which are directly incorporated in the end products;

(ii) "end products" means those articles, materials, and supplies, which are to be acquired under this contract for public use; and

(iii) a "domestic source end product" means (A) an unmanufactured end product which has been mined or produced in the United States and (B) an end product manufactured in the United States if the cost of the components thereof which are mined, produced, or manufactured in the United States exceeds 50 percent of the cost of all its components. For the purposes of this (a) (iii) (B), components of foreign origin of the same type or kind as the products referred to in (b) (ii) or (iii) of

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manufactured in the U. ed States.

(b) The Contractor agrees that there will be delivered under this contract only domestic source end products, except end products:

(i) which are for use outside the United States;

(ii) which the Government determines are not mined, produced, or manufactured in the United States in sufficient and reasonably available commercial quantities and of a satisfactory quality;

(iii) as to which the Secretary determines the domestic preference to be inconsistent with the public interest; or

(iv) as to which the Secretary determines the cost to the Government to be unreasonable.

(The foregoing requirements are administered in accordance with Executive Order No. 10582, dated December 17, 1954.)

16. CONVICT LABOR.

In connection with the performance of work under this contract, the Contractor agrees not to employ any person undergoing sentence of imprisonment at hard labor.

17. CONTRACT WORK HOURS STANDARDS ACT--OVERTIME COMPENSATION.

This contract, to the extent that it is of a character specified in the Contract Work Hours Standards Act (40 U.S.C. 327-330), is subject to the following provisions and to all other applicable provisions and exceptions of such Act and the regulations of the Secretary of Labor thereunder.

(a) Overtime requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics shall require or permit any laborer or mechanic in any workweek in which he is employed on such work to work in excess of eight hours in any calendar day or in excess of forty hours in such workweek on work subject to the provisions of the Contract Work Hours Standards Act unless such laborer or mechanic receives compensation at a rate not less than one and one-half times his basic rate of pay for all such hours worked in excess of eight hours in any calendar day or in excess of forty hours in such workweek, whichever is the greater number of overtime hours.

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(b) Violation; liability for unpaid wages; liquidated damages. In the event of any violation of the provisions of paragraph (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for his unpaid wages. In addition, such Contractor and subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of paragraph (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed on such work in excess of eight hours or in excess of his standard workweek of forty hours without payment of the overtime wages required by paragraph (a).

(c) Withholding for unpaid wages and liquidated damages. The Contracting Officer may withhold from the Government Prime Contractor, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in the provisions of paragraph (b).

(d) Subcontracts. The Contractor shall insert paragraphs (a) through (d) of this clause in all subcontracts, and shall require their inclusion in all subcontracts of any tier.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for three years from the completion of the contract.

18. EQUAL OPPORTUNITY (APR. 1964).

(The following clause is applicable unless this contract is exempt under the rules and regulations of the President's Committee on Equal Employment Opportunity (41 C.F.R. Chapter 60). Exemptions include contracts and subcontracts (i) not exceeding $10,000, (ii) not exceeding $100,000 for standard commercial supplies or raw materials, and (iii) under which work is performed outside the United States and no recruitment of workers within the United States is involved.

During the performance of this contract, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, creed, color, or national origin. The Contractor will take affirmative action to ensure that applicants are employed and that employees are treated during employment without regard to their race, creed, color, or national origin.

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Such action shall include but not be limited to, the following: employment, upgrading, demotion, or transfer; recruitment or recruitment advertising; lay-off or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the Contracting Officer setting forth the provisions of this nondiscrimination clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, creed, color, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the Agency Contracting Officer, advising the said labor union or workers' representative of the Contractor's commitments under this nondiscrimination clause, and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 10925 of March 6, 1961, as amended, and of the rules, regulations, and relevant orders of the President's Committee on Equal Employment Opportunity created thereby.

(e) The Contractor will furnish all information and reports required by Executive Order No. 10925 of March 6, 1961, as amended, and by the rules, regulations and orders of the said Committee, or pursuant thereto, and will permit access to his books, records, and accounts by the contracting agency and the Committee for purposes of investigation to ascertain compliance with such rules, regulations and orders.

(f) In the event of the Contractor's noncompliance with the nondiscrimination clause of this contract or with any of the said rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 10925 of March 6, 1961, as amended, and such other sanctions may be imposed and remedies invoked as provided in the said Executive Order or by rule, regulation, or order of the President's Committee on Equal Employment Opportunity, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (g) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the President's Committee on Equal Employment Opportunity issued pursuant to section 303 of Executive Order No. 10925 of March 6, 1961, as amended, so that such provisions

(Provisions continued on next page)

will be binding upon each subcontractor or vendor.* The Contractor will take such action with respect to any subcontract or purchase order as the contracting agency may direct as a means of enforcing such provisions, including sanctions for noncompliance; provided, however, that in the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by the contracting agency, the Contractor may request the United States to enter into such litigation to protect the interest of the United States.

19. APPROVAL.

This contract shall be subject to the written approval of Army Power Procurement Officer or his duly authorized representative and shall not be binding until approved.

*Unless otherwise provided, the "Equal Opportunity" clause is not required to be inserted in subcontracts below the second tier, except for subcontracts involving the performance of "construction work" at the "site of construction" (as those terms are defined in the Committee's rules and regulations) in which case the clause must be inserted in all such subcontracts. Subcontracts may incorporate by reference the "Equal Opportunity" clause.

GAS SERVICE SPECIFICATIONS Various Delivery Points

1. SPECIFIC PREMISES TO BE SERVED on Fort Richardson
2. ESTIMATED SERVICE:
   Estimated maximum demand: 10 MCF per hour. per Delivery Point
   200 MCF per day. " " "
   Estimated annual consumption 50,000 MCF. " " "
   (The Government is in no way obligated to use nor is it restricted to above estimate.)
3. POINT OF DELIVERY. The point of delivery of gas shall be Various.
4. QUALITY:
   (a) The gas delivered hereunder shall be natural gas. The gas so delivered shall contain no less than 950 Btu per cubic foot. The unit of volume to determine total heating value shall be one (1) cubic foot of gas saturated with water vapor at a temperature of sixty degrees (60°) Fahrenheit and an absolute pressure equivalent to thirty (30) inches of mercury at thirty-two degrees (32°) Fahrenheit.
   (b) The gas delivered:
      (i) shall be commercially free from dust or other solid or liquid matter which might interfere with its merchantability or cause injury to or interference with proper operation of the lines, regulators, meters, and other equipment of the Government.
      (ii) shall not contain more than a trace of hydrogen sulphide per one hundred (100) cubic feet of gas, as determined by methods prescribed in Standards for Gas Service, Circular of the National Bureau of Standards, No. 405, page 134 (1934 edition), and shall be considered free from hydrogen sulphide if a strip of white filter paper, moistened with a solution containing five percent (5%) by weight of lead acetate, is not distinctly darker than a second paper freshly moistened with the same solution, after the first paper has been exposed to the gas for one (1) minute in an apparatus of approved form, through which the gas is flowing at the rate of approximately five (5) cubic feet per hour, the gas not impinging directly from a jet upon the test paper;
      (iii) shall not contain more than twenty (20) grains of total sulphur per one hundred (100) cubic feet.

In the event the gas contains more than a trace of hydrogen sulphide per one hundred (100) cubic feet or more than twenty (20) grains of total sulphur per one hundred (100) cubic feet, by test prescribed by the Bureau of Standards or other recognized method, then upon the request of the Government, the Contractor shall reduce the hydrogen sulphide content to not more than a trace per one hundred (100) cubic feet and the total sulphur content to twenty (20) grains or less per one hundred (100) cubic feet.

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5. MEASUREMENT

(a) *Unit of measurement and metering base.* The volumetric measurement base shall be one (1) cubic foot of gas at a pressure base of thirty (30) inches of mercury (14.73 pounds per square inch absolute), and without adjustment for water vapor content. To determine the volume of gas delivered, factors for pressure, temperature, specific gravity, and deviation from Boyle's Law shall be applied.

(b) *Atmospheric pressure.* The average absolute atmospheric (barometric) pressure shall be assumed to be fourteen and four-tenths (14.4) pounds per square inch, irrespective of actual elevation or location of the delivery point above sea level or variations in actual barometric pressure from time to time.

(c) *Temperature.* The temperature of the natural gas flowing through the meter or meters shall be the arithmetic average of the hourly temperature record, or shall be read from established tables of monthly averages for the service location.

(d) *Specific gravity.* The specific gravity of the natural gas shall be determined by joint test using an Edwards type Balance, or other approved instrument, at the commencement of deliveries hereunder and as often thereafter as deemed necessary; or if mutually agreed upon, by the use of a recorder, periodically checked with an Edwards type Balance or by other accepted methods.

(e) *Deviation from Boyle's Law.* The deviation from Boyle's Law shall be determined by tests or computed by approved methods based on the composition of the gas and conditions at point of measurement, with such reasonable frequency as is found necessary.

(f) *Measuring equipment.*

(i) The Contractor shall maintain and operate, at the delivery points, measuring stations properly equipped with displacement or orifice meters and other necessary measuring equipment by which the volumes of gas delivered hereunder shall be measured. Orifice meters shall be installed and operated, and gas volumes computed, in accordance with specifications recommended in Gas Measurement Committee Report No. 3, dated April 1955, of the Natural Gas Department of the American Gas Association, as the same may be amended from time to time applied in a practical manner; displacement meter dial readings to be adjusted for varying pressure and temperature conditions. The Government may install such check measuring equipment as it shall desire, *provided* that the equipment shall be so installed as not to interfere with the operations of the Contractor. The Contractor shall have access to check measuring equipment at all reasonable hours, but the reading, calibrating and adjusting thereof and the changing of charts shall be done only by the Government unless otherwise agreed.

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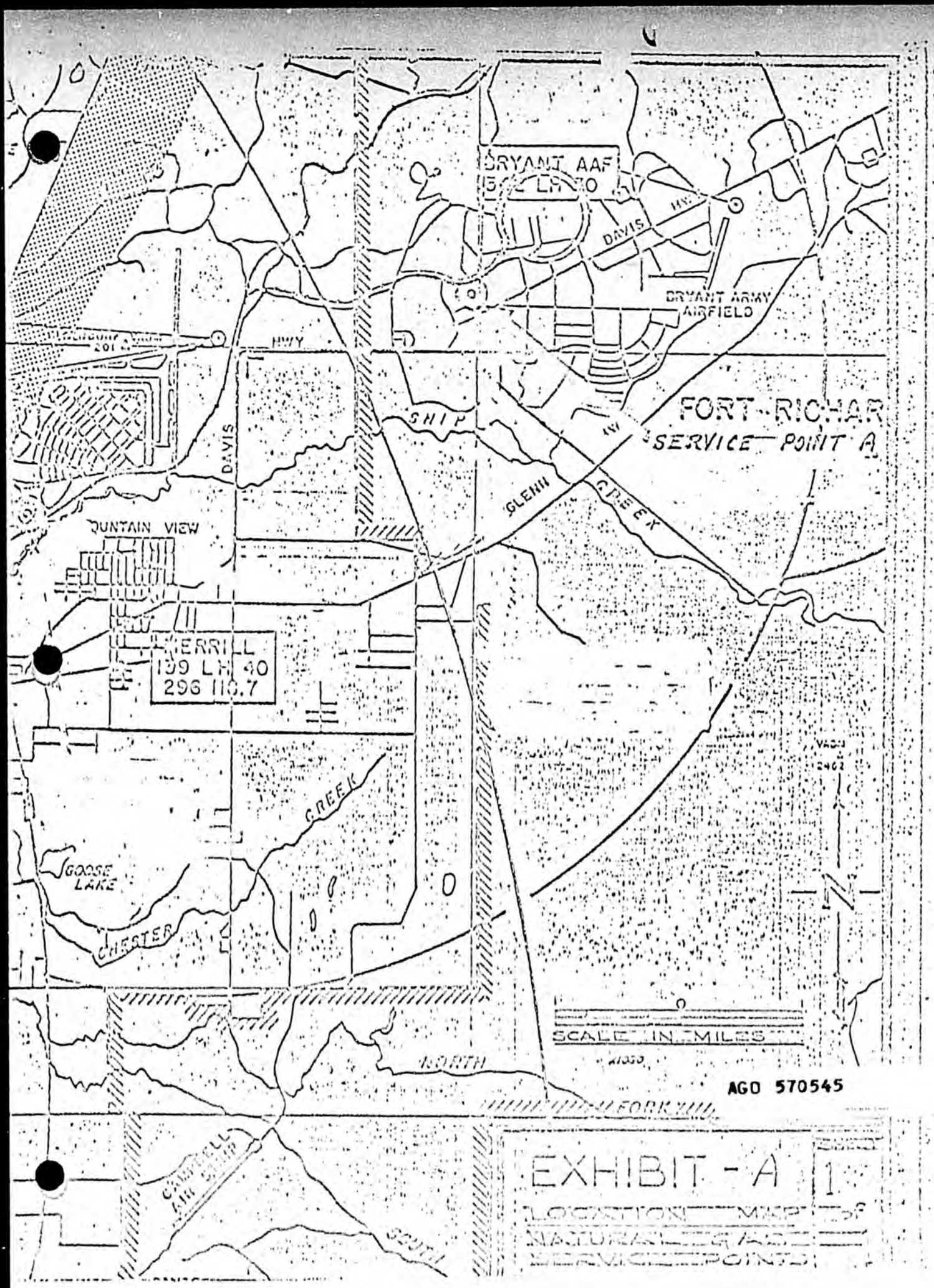
(ii) Both the Contractor and the Government shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment used in measuring deliveries. The records from such measuring equipment shall remain the property of the owner but, upon request, each shall submit to the other its records and charts, or true copies thereof, together with calculations therefrom, for inspection and verification, subject to return within thirty (30) days after receipt thereof, after which return the Contractor's charts and records shall be kept on file by the Contractor for the mutual use of both parties for such period and to the extent required by law.

(iii) Reasonable care shall be exercised in the installation, maintenance, and operation of any pressure regulating equipment to avoid any inaccuracy in the determination of the volume of gas delivered.

6. General

Natural gas shall be delivered at various points along Contractor's transmission line through Fort Richardson as may be requested by the government from time to time. Contractor shall maintain at the point of delivery a regulated pressure within ten percent of the pressure requested by the Contracting Officer, but shall not be required to deliver more than sixty (60) psig. Metering shall be done by instruments of standard manufacture.

7. Additions: Exhibits A & B attached hereto and made a part hereof.
Exhibit C, attached hereto and made a part hereof.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AGO 570545
EXHIBIT - A
LOCATION MAP
NATURAL GAS
SERVICE POINTS
1

SUPPLEMENTAL SPECIFICATIONS FOR SERVICE POINT A.

1. METERING: Gas shall be measured by one positive displacement type meter.

2. PRESSURE: The Contractor shall maintain at the point of delivery a regulated pressure within ten percent of the pressure requested by the Contracting Officer but shall not be required to maintain more than 60 pounds or less than 10 pounds per square inch gauge.

3. SIZE OF PIPELINE TO POINT OF DELIVERY 6 INCHES DIAMETER; OPERATING PRESSURE 200 psig.

4. APPLICABLE RATE SCHEDULE: I

Contract Number DAFA 03-72C0035
EXHIBIT B.

"STABILIZATION OF PRICES, RENTS, WAGES, AND SALARIES (1971 August)
A. By Executive Order 11615, dated August 15, 1971, the President stabilized prices, rents, wages, and salaries. The Contractor represents that to the best of his knowledge and belief he is in complete compliance with Executive Order 11615. Further, the Contractor warrants that the amounts invoiced under this contract will not exceed the lower of (1) the contract price, or (2) the maximum levels established in accordance with the Order.
B. The Contractor agrees to insert the substance of this clause including this paragraph (B), in all subcontracts for supplies or services issued under this Contract.

DEPARTMENT OF THE ARMY
HEADQUARTERS, U. S. ARMY GARRISON, FORT RICHARDSON
Fort Richardson, Alaska 99505

DETERMINATION AND FINDINGS
DAFA03 72 C 0035

Authority to Negotiate an Individual Contract

Upon the basis of the following findings and determination, the proposed contract described below may be negotiated without formal advertising pursuant to the authority of 10 U.S.C. 2304 (a) (2), as implemented by paragraph 3-202.2 (vi) of the Armed Services Procurement Regulation.

FINDINGS

1. I hereby certify there is no GSA contract available to provide natural gas in the Anchorage Area.

DETERMINATION

1. Therefore I determine that it is necessary to contract for utility services with available commercial operators per ASPR 5-800 et

DATE 3/30/71 S. E. Eriksson
S. E. ERIKSSON
Contracting Officer

FINDINGS

2. Contractor is the sole source for natural gas utility service in the Anchorage Area.

DETERMINATION

2. I therefore determine that it is necessary to contract for utility service per 10 USC - 2304 A (10)

DATE 3/30/71 S. E. Eriksson
S. E. ERIKSSON
Contracting Officer

FINDINGS

3. Contractor will not agree for a termination period of less than 90 days.

DETERMINATION

3. I therefore determine that it is proper to provide for 90 days' termination per ASPER S5-106.2.

DATE 3/30/71 S. E. Eriksson
S. E. ERIKSSON
Contracting Officer

AGO 570548

Signed 3:00 pm this 14th day of January

UTILITY SERVICE CONTRACT

Contract No. DAFA03 67 C 0084

DEPARTMENT OF THE ARMY

NEGOTIATED NATURAL GAS SERVICE CONTRACT

Elmendorf AFB and Fort Richardson, Alaska

Alaska Pipeline Company (Contractor) P.O. Box 1855, Anchorage, Alaska, 99501 (Contractor's Address)

Premises are Government Owned

Estimated annual cost hereunder $1,839,000.00

Invoices will be rendered to Purchasing and Contracting Officer at Fort Richardson, Box 471, APO Seattle 98749

Payments will be made by Finance Officer at Fort Richardson, Alaska

This negotiated contract is made pursuant to the provisions of 10 U. S. C. 2304 (a) (10), and delegation of authority dated 11 October 1954 from the Administrator, General Services Administration, to the Secretary of Defense, under the provisions of the Federal Property and Administrative Services Act of 1949 (63 Stat. 377), as amended.

Appropriation chargeable: Applicable funds will be cited on Delivery Orders issued against this contract.

RECEIVED

24 JAN 74 12: 1

Contract No. DAFA03 67 C 0084

DEPARTMENT OF THE ARMY

NEGOTIATED NATURAL GAS SERVICE CONTRACT

This CONTRACT, entered into as of _____, by and between the UNITED STATES OF AMERICA, hereinafter called the "Government", represented by the Contracting Officer executing this contract, and Alaska Pipeline Company whose address is P.O. Box 1855, Anchorage, Alaska, 99501 hereinafter called the "Contractor",

WITNESSETH That the parties hereto do mutually agree as follows:

1. SCOPE AND TERM OF CONTRACT. (a) Subject to the terms and conditions hereinafter set forth, the Contractor shall sell and deliver to the Government and the Government shall purchase and receive from the Contractor, Natural Gas Service (hereinafter called "Service") requested by the Government from the Contractor at the premises to be served hereunder (hereinafter called the "Service Location"), all in accordance with Natural Gas Service Specifications, Exhibits "A-1" and "A-2"; "Rate Schedule", Exhibit B; "Transmission and Service Data", Exhibit C; and "Location Map", Exhibit D; all attached hereto and made a part hereof.

(b) This contract shall continue in effect for ten (10) years from the date service is commenced hereunder; and thereafter until terminated at the option of either party by the giving of not less than ninety (90) days advance written notice, in which event no termination charge shall apply; except that in the event this contract is terminated by the Government by reason of the Government's decision to discontinue operation of the premises served by the central heat and power plants at the Service Locations or by reason of force majeure, and in consideration of the furnishing and installing at Contractor's expense of the Gas Delivery Facilities required hereunder as described in Exhibit "C" attached hereto and made a part of this contract, the Government shall pay to Contractor as a termination charge $1,200,000 (one million two hundred thousand dollars) less $10,000 (ten thousand dollars) multiplied by the number of months (not to exceed 120) service has been received and paid for prior to the date of such termination.

(i) Funds are presently not available to accomplish construction of facilities necessary for conversion of Plant fuel burning equipment. No obligation of any kind on the part of the Government would arise under this contract unless, and until, funds are appropriated for the conversion of the Plants to natural gas, and the Contracting Officer so advises the Contractor in writing. If the Contractor is not so notified by 1 April 1968, any obligations of both parties under the contract will cease, and the contract will automatically be cancelled.

(ii) Funds are not presently available for this procurement. The Government's obligation hereunder is contingent upon the availability of appropriated funds from which payment for the contract purposes can be made. No legal liability on the part of the Government for payment of any money shall arise unless and until funds are made available to the Contracting Officer for this procurement and notice of such availability, to be confirmed in writing by the Contracting Officer, is given to the Contractor.

(c) (i) For and in consideration of the faithful performance of the stipulations of this contract, the Contractor shall be paid by the designated disbursing office or officer for service herein contracted for, at the rates

AGO 570550

and under the terms and conditions herein set forth; provided, that the Government shall be liable for the minimum monthly charge specified in this contract commencing with the billing period in which service is initially furnished thereto and continuing until this contract is terminated, except that the minimum monthly charge specified in this contract shall be equitably prorated for the billing period in which commencement and termination of this contract shall become effective.

(ii.) The Contractor hereby declares that said rates are not in excess of the lowest rates now available to any prospective customer under like conditions of service, and agrees that during the life of this contract the Government shall continue to be billed at the lowest available rate for similar conditions of service.

(iii.) Recognition is given to the fact that the Government fiscal year ends on 30 June. Payments hereunder shall be contingent upon the availability of appropriations therefor, and shall not be made in advance of service rendered.

(iv) All bills for service shall be paid without penalty or interest and the Government shall be entitled to any discounts customarily applicable to payment of bills by all customers of the Contractor.

(v) Invoices for service rendered hereunder shall contain statements of the meter readings at the beginning of the billing period, meter constants, consumption during the billing period, and such other pertinent data as shall be required by the Government.

2. TECHNICAL PROVISIONS. (a) Measurement of service. (i) All service furnished by the Contractor shall be measured by suitable metering equipment of standard manufacture, to be furnished, installed, maintained, calibrated, and read by the Contractor at its expense. When more than a single meter is installed at the service location, the readings thereof shall be billed conjunctively. In the event any meter fails to register or registers incorrectly the service furnished therethrough, the parties shall agree upon the length of period during which such meter failed to register or registered incorrectly and the quantity of service delivered therethrough during such period and, upon agreement, an appropriate adjustment based thereon shall be made in the Government's bills. For the purpose of the preceding sentence, any meter which registers not more than two (2) per cent slow or fast shall be deemed correct.

(ii) The Contractor, so far as possible, shall read all meters at periodic intervals of approximately thirty (30) days. All billings based on meter readings of less than twenty-seven (27) days or more than thirty-two (32) days shall be prorated accordingly.

(b) Meter test. The Contractor, at its expense, shall periodically inspect and test the meters installed by it at intervals not exceeding one (1) year. At the written request of the Contracting Officer the Contractor shall make additional tests of any or all of such meters in the presence of Government representatives. The cost of such additional tests shall be borne by the Government if the percentage of error is found to be not more than two (2) per cent slow or fast. No meter shall be placed in service or allowed to remain in service which has an error in registration in excess of two (2) per cent under normal operating conditions.

(c) Change in volume or character. Reasonable notice shall, so far as possible, be given by the Contracting Officer to the Contractor respecting any material changes proposed in the volume or characteristics of the utility service required at each location.

(d) Continuity of service and consumption. (i) The Contractor shall use reasonable diligence to provide a regular and uninterrupted supply of service at the service location, but shall not be liable for damages, breach of contract or otherwise to the Government for failure, suspension, diminution or other variations of service occasioned by or in consequence of any cause beyond the control of the Contractor, including but not limited to acts of God or of the public enemy, fires, floods, earthquakes or other catastrophes, strikes or failure or breakdown of transmission or other facilities; provided, that when any such failure, suspension, diminution, or variation of service shall aggregate more than ten (10) hours during any billing period hereunder, an equitable adjustment shall be made in the monthly rates specified in this contract (including the minimum monthly charge).

(ii) In the event the Government is unable to operate the service location in whole or in part for any cause beyond its control, including but not limited to acts of God or of the public enemy, fires, floods, earthquakes, or other catastrophes, or strikes, an equitable adjustment shall be made in the monthly rates specified in this contract (including the minimum monthly charge) if the period during which the Government is unable to operate such service location in whole or in part shall exceed fifteen (15) days during any billing period hereunder.

3. RATES AND CHARGES. (a) For all service furnished under this contract to the service location the Government shall pay the Contractor at the rate set forth in the attached rate schedule.

(b) For purposes of charges under paragraph (a) of this clause, any demands due to faulty operation of, or excessive or fluctuating pressure on, the Contractor's system shall not be included as part of the Government's demand.

4. CONTRACTOR'S FACILITIES. (a) The Contractor, at its expense, shall furnish, install, operate, and maintain all facilities required to furnish service hereunder to and measure such service as of the point of delivery specified in the Service Specifications. Title to all such facilities shall be and remain in the Contractor and the Contractor shall be responsible for all loss of or damage to such facilities.

(b) The Government hereby grants to the Contractor, free of any rental or similar charge, but subject to the limitations specified in this contract, a revocable permit to enter the service location for any proper purpose under this contract, including use of the site or sites agreed upon by the parties hereto for the installation, operation, and maintenance of the facilities of the Contractor required to be located upon Government premises, all of which facilities shall be and remain the sole property of the Contractor and shall, at all times during the life of this contract, be operated and maintained by the Contractor at its expense; and all taxes and other charges in connection therewith, together with all liability arising out of the negligence of the Contractor in the construction, operation, or maintenance of such facilities shall be assumed by the Contractor. Authorized representatives of the Contractor will be allowed access to the facilities of the Contractor at suitable times to perform the obligations of the Contractor with respect to such facilities. Such facilities shall be removed and Government premises restored to their original condition by the Contractor at its expense within a reasonable time after the Government shall revoke the permit herein granted and in any event within a reasonable time after termination of this contract, provided that in event of termination due to the fault of the Contractor, such facilities may be retained in place at the option of the Government until service comparable to that provided for hereunder is obtained elsewhere. It is expressly understood, however, that proper military or Governmental authority may limit or restrict the right of access herein granted in any manner considered by such authority to be necessary for the national security.

5. CHANGE OF RATES. At the request of either party to this contract, said party having reasonable cause therefor, the rates set forth herein shall be renegotiated, and any adjustment so negotiated by mutual agreement shall become effective as of the date of such agreement, provided, however, that any rates so negotiated shall not be in excess of rates to any customer of the contractor having similar conditions of service.

6. OFFICIALS NOT TO BENEFIT. No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this contract, or to any benefit that may arise therefrom; but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

7. COVENANT AGAINST CONTINGENT FEES. The Contractor warrants that no person or selling agency has been employed or retained to solicit or secure this contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee, excepting bona fide employees or bona fide established commercial or selling agencies maintained by the Contractor for the purpose of securing business. For breach or violation of this warranty the Government shall have the right to annul this contract without liability or in its discretion to deduct from the contract price or consideration, or otherwise recover, the full amount of such commission, percentage, brokerage, or contingent fee.

8. ASSIGNMENT OF CLAIMS. No claim under this contract shall be assigned.

9. CONVICT LABOR. In connection with the performance of work under this contract, the Contractor agrees not to employ any person undergoing sentence of imprisonment at hard labor.

10. EQUAL OPPORTUNITY. (The following clause is applicable unless this contract is exempt under the rules and regulations of the Secretary of Labor (41 C.F.R. Chapter 60). Exemptions include contracts and subcontracts (i) not exceeding $10,000, (ii) not exceeding $100,000 for standard commercial supplies or raw materials, and (iii) under which work is performed outside the United States and no recruitment of workers within the United States is involved.

During the performance of this contract, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, creed, color, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, creed, color, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion, or transfer; recruitment or recruitment advertising; lay-off or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notice to be provided by the Contracting Officer setting forth the provisions of this nondiscrimination clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, creed, color, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the Agency Contracting Officer, advising said labor union or worker's representative of the Contractor's commitments under this nondiscrimination clause, and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of Sept 24, 1965, as amended, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of Sept 24, 1965, as amended, and by the rules, regulations, and orders of the said Secretary of Labor, or pursuant thereto, and will permit access to his books, records, and accounts by the contracting agency and the Secretary of Labor for purposes of investigation to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the non-discrimination clause of this contract or with any of the said rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of Sept 24, 1965, as amended, and such other sanctions may be imposed and remedies invoked as provided in the said Executive Order or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraph (a) through (g) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to section 204 of Executive Order No. 11246 of Sept 24, 1965, as amended, so that such provisions will be binding upon each subcontractor or vendor*. The Contractor will take such action with respect to any subcontract or purchase order as the contracting agency may direct as a means of enforcing such provisions, including sanctions for non-compliance: provided, however, that in the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by the contracting agency, the Contractor may request the United States to enter into such litigation to protect the interest of the United States.

*Unless otherwise provided, the "Equal Opportunity" clause is not required to be inserted in subcontracts below the second tier, except for subcontracts involving the performance of "construction work" at the "site of construction" (as those terms are defined in the Secretary of Labor's rules and regulations) in which case the clause must be inserted in all such subcontracts. Subcontracts may incorporate by reference the "Equal Opportunity" clause.

11. DISPUTES. (a) Except as otherwise provided in this contract, any dispute concerning a question of fact arising under this contract which is not disposed of by agreement shall be decided by the Contracting Officer, who shall reduce his decision to writing and mail or otherwise furnish a copy thereof to the Contractor. The decision of the Contracting Officer shall be final and conclusive unless, within 30 days from the date of receipt of such copy, the Contractor mails or otherwise furnishes to the Contracting Officer a written appeal addressed to the Secretary. The decision of the Secretary or his duly authorized representative for the determination of such appeals shall be final and conclusive unless determined by a court of competent jurisdiction to have been fraudulent, or capricious, or arbitrary, or so grossly erroneous as necessarily to imply bad faith, or not supported by substantial evidence. In connection with any appeal proceeding under this clause, the Contractor shall be afforded an opportunity to be heard and to offer evidence in support of his appeal. Pending final decision of a dispute hereunder, the Contractor shall proceed diligently with the performance of the contract and in accordance with the Contracting Officer's decision.

(b) This "Disputes" clause does not preclude consideration of law questions in connection with decisions provided for in paragraph (a) above; provided, that nothing in this contract shall be construed as making final the decision of any administrative official, representative, or board on a question of law.

12. GRATUITIES. (a) The Government may, by written notice to the Contractor, terminate the right of the Contractor to proceed under this contract if it is found, after notice and hearing, by the Secretary or his duly authorized representative, that gratuities (in the form of entertainment, gifts, or otherwise) were offered or given by the Contractor, or any agent or representative of the Contractor, to any officer or employee of the Government with a view toward securing a contract or securing favorable treatment with respect to the awarding or amending, or the making of any determinations with respect to the performing of such contract; provided, that the existence of the facts upon which the Secretary or his duly authorized representative makes such findings shall be in issue and may be reviewed in any competent court.

(b) In the event this contract is terminated as provided in paragraph (a) hereof, the Government shall be entitled (i) to pursue the same remedies against the Contractor as it could pursue in the event of a breach of the contract by the Contractor, and (ii) as a penalty in addition to any other damages to which it may be entitled by law, to exemplary damages in an amount (as determined by the Secretary or his duly authorized representative) which shall be not less than three nor more than ten times the costs incurred by the Contractor in providing any such gratuities to any such officer or employee.

(vii) The term "British Thermal Unit" means the amount of heat required to raise the temperature of one pound of water from 59° Fahrenheit to 60° Fahrenheit at a pressure of 14.65 pounds per square inch absolute.

(viii) The term "Billing Period" means a month as defined herein.

(ix) The term "Total Heating Value" means the heating value of the gas as determined by a mutually acceptable recognized independent testing laboratory, all cost for which shall be borne by the Contractor. The Contractor shall furnish the Government a certified copy of all test results so obtained, and the Government may at any time request the Contractor to provide additional tests to supplement periodic testing which may from time to time be scheduled hereunder. Test results shall be reported in Btu per cubic foot of gas, as herein defined.

(x) The term "Therm" means the sale measuring unit consisting of one hundred thousand (100,000) British Thermal Units. The number of therms delivered shall be determined by multiplying the number of cubic feet of gas delivered (as defined herein) by the Total Heating Value of such gas in British Thermal Units per cubic foot and dividing the product by one hundred thousand (100,000).

14. CONFLICTS. To the extent of any inconsistency between the provisions of this contract, and any schedule, rider, or exhibit incorporated in this contract by reference or otherwise, or any of the Contractor's rules and regulations, the provisions of this contract shall control.

15. APPROVAL. This contract is subject to the manual approval of the Department of Army Power Procurement Officer or his duly authorized representative and shall not be binding until so approved.

IN WITNESS WHEREOF, The parties hereto have executed this contract as of the day and year first above written.

THE UNITED STATES OF AMERICA

By Walter C. Williams

WALTER C. WILLIAMS
Contracting Officer

Alaska Pipeline Company
(Contractor)

By [signature]

Title Vice President & General Manager

RECEIVED
JAN 24 1974
State of Alaska
Public Utilities Commission

CERTIFICATE

I, Robert D Heath, certify that I am the Asst Secretary of the corporation named as Contractor in the foregoing contract; that Dale Teel who signed said contract on behalf of the Contractor was then Vice President of said corporation; that said contract was duly signed for and on behalf of said corporation by authority of its governing body and is within the scope of its corporate powers.

(Corporate Seal) Robert D. Heath

Sheet 11 of 11

AGO 570558

EXHIBIT "A-1"

(Attached to and made a part of Contract No. DAFA03 67 C 0084)

GAS SERVICE SPECIFICATIONS

1. PREMISES TO BE SERVED.

✓ Fort Richardson, Anchorage, Alaska

2. ESTIMATED SERVICE REQUIREMENTS.

Estimated maximum demand:	600 MCF per hour
	15,000 MCF per day
Estimated annual consumption:	2,750,000 MCF

The Government is in no way obligated to use nor is it restricted to the above estimated requirements.

3. POINT OF DELIVERY.

The point of delivery of gas shall be at the outlet side of Contractor's gas meter and regulator station located at a mutually agreed upon point at the site of the power plant.

4. QUALITY.

(a) The gas delivered hereunder shall be Natural Gas. The gas so delivered shall contain not less than 950 Btu per cubic foot. The unit of volume for the purpose of determining total heating value shall be one (1) cubic foot of gas saturated with water vapor at a temperature of sixty degrees (60°) Fahrenheit and an absolute pressure equivalent to thirty (30) inches of Mercury at thirty-two degrees (32°) Fahrenheit.

(b) The gas delivered:

(1) Shall be commercially free from dust or other solid or liquid matter which might interfere with its merchantability or cause injury to or interference with proper operation of the lines, regulators, meters or any equipment of Government;

(2) Shall not contain more than a trace of Hydrogen Sulphide per one hundred (100) cubic feet of gas, as determined by methods prescribed in Standards for Gas Service, circular of the National Bureau of Standards, No. 405, page 134 (1934 Edition), and shall be considered free from hydrogen sulphide if a strip of white filter paper, moistened with a solution containing five per cent (5%) by weight of lead acetate, is not distinctly darker than a second paper freshly moistened with the same solution, after the first paper has been exposed to the gas for one (1) minute in an apparatus of approved form, through which the gas is flowing at the rate of approximately five (5) cubic feet per hour, the gas not impinging directly from a jet upon the test paper;

(3) Shall not contain more than twenty (20) grains of total sulphur per one hundred (100) cubic feet;

(4) In the event the gas contains more than a trace of hydrogen sulphide per one hundred (100) cubic feet or more than twenty (20) grains of total sulphur per one hundred (100) cubic feet, by test prescribed by the Bureau of Standards or other recognized method, then upon the request of Government, Contractor shall reduce the hydrogen sulphide content to not more than a trace per one hundred (100) cubic feet and the total sulphur content to twenty (20) grains or less per one hundred (100) cubic feet.

5. MEASUREMENT.

(a) Unit of measurement and metering base. The volumetric measurement base shall be one (1) cubic foot of gas at thirty (30) inches of Mercury (14.73 pounds per square inch absolute), and without adjustment for water vapor content. To determine the volume of gas delivered, factors for pressure, temperature, specific gravity, and deviation from Boyle's law shall be applied.

(b) Atmospheric pressure. The average absolute atmospheric (Barometric) pressure shall be assumed to be 14.4 pounds to the square inch, irrespective of actual elevation or location of the delivery point above sea level or variations in actual barometric pressure from time to time.

(c) Temperature. The temperature of the natural gas flowing through the meter or meters shall be the arithmetic average of the hourly temperature record; or read from established tables of monthly averages for the service location.

(d) Specific gravity. The specific gravity of the natural gas shall be determined by joint test using an Edwards type Balance, or other approved instrument, at the commencement of deliveries hereunder and as often thereafter as deemed necessary; or if mutually agreed upon, by the use of a recorder, periodically checked with an Edwards type Balance or by other accepted methods.

(e) The deviation from Boyle's Law shall be determined by tests or computed by approved methods based on the composition of the gas and conditions at point of measurement, with such reasonable frequency as found necessary.

(f) Measuring equipment. Contractor will maintain and operate, at the delivery point, measuring stations properly equipped with displacement or orifice meters and other necessary measuring equipment by which the volumes of gas delivered hereunder shall be measured. Orifice meters shall be installed and operated, and gas volumes computed, in accordance with specifications recommended in Gas Measurement Committee Report No. 3, (April, 1955) of the American Gas Association, as the same may be amended from time to time, applied in a practical manner; displacement meter dial readings to be adjusted for varying pressure and temperature conditions. Government may install such check measuring equipment as it shall desire, provided that such equipment shall be so installed as not to interfere with the operations of Contractor. Contractor shall have access to such check measuring equipment at all reasonable hours, but the reading, calibrating, and adjusting thereof and the changing of charts shall be done only by Government unless otherwise agreed upon.

Both Contractor and Government shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment used in measuring deliveries. The records from such measuring equipment shall remain the property of their own, but upon request, each will submit to the other its records and charts, or true copies thereof, together with calculations therefrom, for inspection and verification, subject to return within thirty (30) days after receipt thereof, after which return the Contractor's charts and records shall be kept on file by the Contractor for the mutual use of both parties for such period and to such extent as may be required by law.

Reasonable care shall be exercised in the installation, maintenance, and operation of any pressure regulating equipment to avoid any inaccuracy in the determination of the volume of gas delivered.

6. METERING AND BILLING.

Gas shall be measured by See Exhibit C meter(s).
Number installed

7. PRESSURE.

Contractor will maintain at the point of delivery a regulated pressure within ten per cent (10%) of the pressure requested by the Contracting Officer but shall not be required to maintain more than fifty (50) pounds per square inch gauge.

8. SIZE OF PIPELINE TO POINT OF DELIVERY.

See Exhibit C

EXHIBIT "A-2"

(Attached to and made a part of Contract No. DAFA03 67 C 0084)

GAS SERVICE SPECIFICATIONS

1. PREMISES TO BE SERVED.

Elmendorf Air Force Base, Anchorage, Alaska

2. ESTIMATED SERVICE REQUIREMENTS.

Estimated maximum demand:	675,000 MCF per hour
	17,000 MCF per day
Estimated annual consumption:	3,400 MCF

The Government is in no way obligated to use nor is it restricted to the above estimated requirements.

3. POINT OF DELIVERY.

The point of delivery of gas shall be at the outlet side of Contractor's gas meter and regulator station located at a mutually agreed upon point at the site of the power plant.

4. QUALITY.

(a) The gas delivered hereunder shall be Natural Gas. The gas so delivered shall contain not less than 950 Btu per cubic foot. The unit of volume for the purpose of determining total heating value shall be one (1) cubic foot of gas saturated with water vapor at a temperature of sixty degrees (60°) Fahrenheit and an absolute pressure equivalent to thirty (30) inches of Mercury at thirty-two degrees (32°) Fahrenheit.

(b) The gas delivered:

(1) Shall be commercially free from dust or other solid or liquid matter which might interfere with its merchantability or cause injury to or interference with proper operation of the lines, regulators, meters or any equipment of Government;

(2) Shall not contain more than a trace of Hydrogen Sulphide per one hundred (100) cubic feet of gas, as determined by methods prescribed in Standards for Gas Service, circular of the National Bureau of Standards, No. 405, page 134 (1934 Edition), and shall be considered free from hydrogen sulphide if a strip of white filter paper, moistened with a solution containing five per cent (5%) by weight of lead acetate, is not distinctly darker than a second paper freshly moistened with the same solution, after the first paper has been exposed to the gas for one (1) minute in an apparatus of approved form, through which the gas is flowing at the rate of approximately five (5) cubic feet per hour, the gas not impinging directly from a jet upon the test paper;

(3) Shall not contain more than twenty (20) grains of total sulphur per one hundred (100) cubic feet;

(4) In the event the gas contains more than a trace of hydrogen sulphide per one hundred (100) cubic feet or more than twenty (20) grains of total sulphur per one hundred (100) cubic feet, by test prescribed by the Bureau of Standards or other recognized method, then upon the request of Government, Contractor shall reduce the hydrogen sulphide content to not more than a trace per one hundred (100) cubic feet and the total sulphur content to twenty (20) grains or less per one hundred (100) cubic feet.

5. MEASUREMENT.

(a) Unit of measurement and metering base. The volumetric measurement base shall be one (1) cubic foot of gas at thirty (30) inches of Mercury (14.73 pounds per square inch absolute), and without adjustment for water vapor content. To determine the volume of gas delivered, factors for pressure, temperature, specific gravity, and deviation from Boyle's law shall be applied.

(b) Atmospheric pressure. The average absolute atmospheric (Barometric) pressure shall be assumed to be 14.4 pounds to the square inch, irrespective of actual elevation or location of the delivery point above sea level or variations in actual barometric pressure from time to time.

(c) Temperature. The temperature of the natural gas flowing through the meter or meters shall be the arithmetic average of the hourly temperature record; or read from established tables of monthly averages for the service location.

(d) Specific gravity. The specific gravity of the natural gas shall be determined by joint test using an Edwards type Balance, or other approved instrument, at the commencement of deliveries hereunder and as often thereafter as deemed necessary; or if mutually agreed upon, by the use of a recorder, periodically checked with an Edwards type Balance or by other accepted methods.

(e) The deviation from Boyle's Law shall be determined by tests or computed by approved methods based on the composition of the gas and conditions at point of measurement, with such reasonable frequency as found necessary.

(f) Measuring equipment. Contractor will maintain and operate, at the delivery point, measuring stations properly equipped with displacement or orifice meters and other necessary measuring equipment by which the volumes of gas delivered hereunder shall be measured. Orifice meters shall be installed and operated, and gas volumes computed, in accordance with specifications recommended in Gas Measurement Committee Report No. 3, (April, 1955) of the American Gas Association, as the same may be amended from time to time, applied in a practical manner; displacement meter dial readings to be adjusted for varying pressure and temperature conditions. Government may install such check measuring equipment as it shall desire, provided that such equipment shall be so installed as not to interfere with th operations of Contractor. Contractor shall have access to such check measuring equipment at all reasonable hours, but the reading, calibrating, and adjusting thereof and the changing of charts shall be done only by Government unless otherwise agreed upon.

Both Contractor and Government shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment used in measuring deliveries. The records from such measuring equipment shall remain the property of their own, but upon request, each will submit to the other its records and charts, or true copies thereof, together with calculations therefrom, for inspection and verification, subject to return within thirty (30) days after receipt thereof, after which return the Contractor's charts and records shall be kept on file by the Contractor for the mutual use of both parties for such period and to such extent as may be required by law.

Reasonable care shall be exercised in the installation, maintenance, and operation of any pressure regulating equipment to avoid any inaccuracy in the determination of the volume of gas delivered.

6. METERING AND BILLING.

Gas shall be measured by See Exhibit C meter(s).
Number installed

7. PRESSURE.

Contractor will maintain at the point of delivery a regulated pressure within ten per cent (10%) of the pressure requested by the Contracting Officer but shall not be required to maintain more than fifty (50) pounds per square inch gauge.

8. SIZE OF PIPELINE TO POINT OF DELIVERY.

See Exhibit C

EXHIBIT "B"
RATE SCHEDULE

For and in consideration of the faithful performance of the stipulations of this contract, the Contractor shall be paid by the designated disbursing office or officer for Service herein contracted for, at the rate of $0.034 (3.4¢) per therm; provided, that the Government shall be liable for portions of the minimum monthly charge of $70,000 specified in this contract, commencing with the billing period in which Service is initially made available at either of the Service Locations, as follows:

Billing Period Following Date Service is Initially Made Available	Amount of Minimum Monthly Charge
First	Zero
Second	$10,000 per month
Third	20,000 per month
Fourth	30,000 per month
Fifth	40,000 per month
Sixth	50,000 per month

The minimum monthly charge during the sixth billing period as shown above shall be $50,000 per month; and thereafter the minimum monthly charge shall be $70,000 per month except that the minimum monthly charge shall be equitably prorated for the billing period in which termination of this contract shall become effective; provided, however, that during the second 12 billing periods following the date service is initially made available, the Government shall be entitled to receive gas, paid for but not taken by the Government during the first 12 billing periods hereunder, without further charge in any such month in which the Government's requirements exceed the amount of the minimum monthly charge as herein provided.

The Contractor agrees that service will be initially made available on 1 July 1968 provided that written notice to proceed is received in accordance with Article 1(b) (i) of the contract not less than one hundred and twenty (120) "construction days" prior. It is agreed, for the purposes of this section, that "construction days" are defined as only those working days falling within the period of 1 May through 30 September.

To the price payable by the Government to the Contractor for natural gas, the Contractor shall have the right, in the absence of exemptions under state or local laws for service to the United States, to add and the Government will pay to the Contractor, with respect to gas delivered hereunder, the amount of any sales, transactions, service, occupation, production, severance, transportation, gathering, export or excise pipeline tax or charge of similar or equivalent nature or effect hereafter imposed by any governmental authority of the state or federal government, or any subdivision thereof, upon or in respect to the production, severance, transportation and/or sale of natural gas by the Contractor if the Contractor becomes liable therefor, whether under direct or indirect imposition or pursuant to contract obligations from consumers pursuant to regulations of a public utility commission, if any, or in the absence of such a commission, the taxes are made uniformly applicable to charges made the general public.

EXHIBIT "C"
TRANSMISSION AND SERVICE DATA

GENERAL

The Contractor shall construct natural gas transmission lines from its gas system to the Government's power plants at Fort Richardson and Elmendorf Air Force Base, and shall construct metering and regulating stations at mutually agreed upon points at the sites or vicinities of these power plants. A sketch of the routing of these transmission lines is attached hereto. The Contractor shall defer installation of these facilities until the Government's Contracting Officer gives written notification to proceed.

TRANSMISSION LINES

Nominal Diameter	Approx. Length	Location Start	Location End	Pipe Grade	Wall Thickness	Amount
12"	31,000 ft	City Gate Station	"Y" at Base Hospital	5LX 46	0.250	$725,000
10"	13,000 ft	"Y" at Base Hospital	"Y" Mt. View	5LX 42	0.219	200,000
10"	3,000 ft	"Y" Mt. View	Outer Bolt Line Mt. View	5LX 42	0.219	50,000
8"	10,500 ft	"Y" at Base Hospital	Fort Richardson Power Plant	5LX 42	0.188	125,000
8"	4,500 ft	"Y" Mt. View	Elmendorf Power Plant	5LX 42	0.188	50,000

METERING

Metering stations at the power plant sites or vicinities shall be installed for orifice measurement, each with two meter tube assemblies (one 6" and one 4") to provide full range accuracy required under this contract. These stations shall be enclosed in suitable structures to provide protection from tampering and weather. 50,000

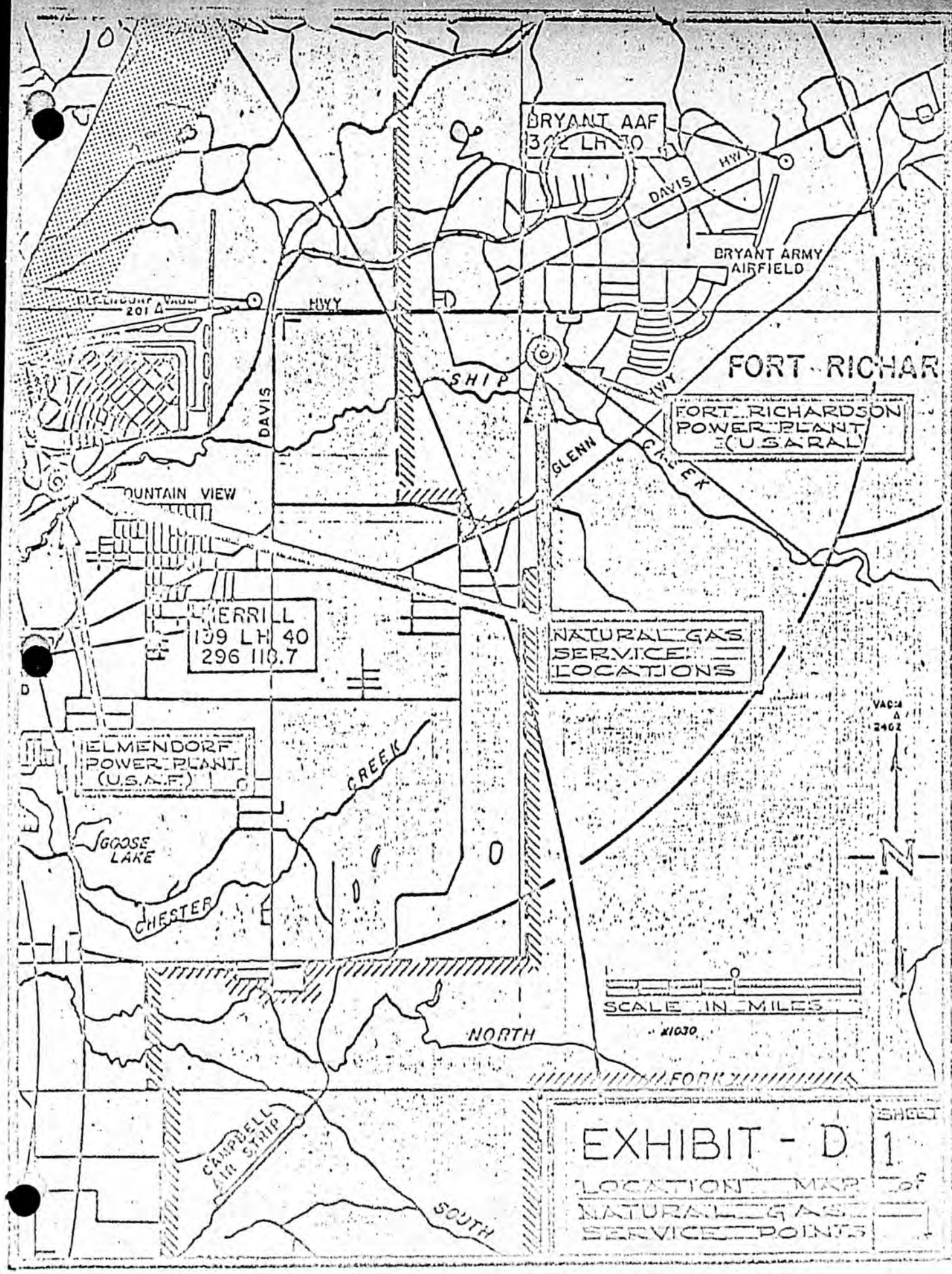
TOTAL AMOUNT $1,200,000

PRESSURE REGULATION

Inlet pressures of the metering stations shall be controlled by regulators and relief valves of standard manufacture, and installed to provide the range of flexibility required for satisfactory operation.

VALVES

Block valves shall be installed to allow independent operation of each of the Service Locations, Fort Richardson and Elmendorf Air Force Base. Block Valves shall also be installed to allow service to be supplied independently from an extension of Contractor's existing 12" transmission line along Mt. View Drive, inter-connecting with the transmission lines on Government premises at or near the power plant at Elmendorf Air Force Base.


BRYANT AAF
DAVIS
HWY
BRYANT ARMY AIRFIELD
HWY
DAVIS
SHIP
FORT RICHAR
FORT RICHARDSON POWER PLANT (U.S.A.R.A.L.)
GLENN
CREEK
NATURAL GAS SERVICE LOCATIONS
ELMENDORF POWER PLANT (U.S.A.F.)
CREEK
GOOSE LAKE
CHESTER
SCALE IN MILES
NORTH
FORK
CAMPBELL AIR STRIP
SOUTH
EXHIBIT - D
SHEET 1
LOCATION MAP
NATURAL GAS SERVICE POINTS

AGO 570570

UNIT AGREEMENTS

UNIT AGREEMENT FOR THE DEVELOPMENT AND OPERATION

OF THE

NORTH COOK INLET UNIT AREA

AND

KENAI UNIT AREA (with Revisions)

AGO 570572

UNIT AGREEMENT

FOR THE DEVELOPMENT AND OPERATION OF THE

NORTH COOK INLET UNIT AREA

STATE OF ALASKA

THIRD JUDICIAL DISTRICT

DATED NOVEMBER 1, 1966

AGO 570573

UNIT AGREEMENT

FOR THE DEVELOPMENT AND OPERATION OF THE

NORTH COOK INLET UNIT AREA

STATE OF ALASKA

THIRD JUDICIAL DISTRICT

THIS AGREEMENT, entered into as of the 1st day of November, 1966, by and between the parties subscribing, ratifying, or consenting hereto, and herein referred to as the "parties hereto",

WITNESSETH:

WHEREAS, the parties hereto are the owners of working, royalty or other oil and gas interests in the unit area subject to this agreement; and,

WHEREAS, the Commissioner of the Department of Natural Resources, State of Alaska, hereinafter referred to as the "Commissioner", is authorized by Alaska Statute 38.05 and appropriate State Regulations to consent to or approve this agreement on behalf of the State of Alaska, insofar as it covers and includes lands and mineral interests of the State of Alaska; and,

WHEREAS, the parties hereto hold sufficient interests in the North Cook Inlet Unit Area covering the land hereinafter described to give reasonably effective control of operations therein; and,

WHEREAS, it is the purpose of the parties hereto to conserve natural resources, prevent waste, and secure other benefits obtainable through development and operation of the area subject to this agreement under the terms, conditions and limitations herein set forth; and,

WHEREAS, State Lands, as that term is used in this agreement, means those lands title to which is vested or that become vested in the State of

Alaska and lands which have been tentatively approved after state selection and are not covered by an existing Federal oil and gas lease at such time as any right or authority is exercised;

NOW, THEREFORE, in consideration of the premises and the promises herein contained, the parties hereto commit to this agreement their respective interests in the below-defined unit area, and agree severally among themselves as follows:

1. ENABLING ACT AND REGULATIONS. The Alaska Land Act (A.S. 38.05.005-370) and all valid and pertinent oil and gas statutes and regulations including the oil and gas operating statutes and regulations in effect as of the effective date hereof or hereafter issued thereunder governing drilling and producing operations, not inconsistent with the terms hereof or the laws of the State of Alaska are hereby accepted and made a part of this agreement.

2. UNIT AREA. The area specified on the map attached hereto marked Exhibit "A" is hereby designated and recognized as constituting the the unit area, containing 53,397 acres, more or less. Exhibit "A" shows, in addition to the boundary of the unit area, the boundaries and identity of of tracts and leases in said area to the extent known to the Unit Operator.

Exhibit "B" attached hereto is a schedule showing, to the extent known to the Unit Operator, the acreage, percentage, and kind of ownership of oil and gas interests in all land in the unit area. However, nothing herein or in said schedule or map shall be construed as a representation by any party hereto as to the ownership of any interest other than such interest or interests as are shown in said map or schedule as owned by such party.

Exhibits "A" and "B" shall be revised by the Unit Operator whenever changes in the unit area render such revision necessary, or when requested by the Director, Division of Lands of the Department of Natural Resources,

hereinafter referred to as the "Director", and four (4) copies thereof shall be filed with the Director.

The above-described unit area shall, when practicable, be expanded to include therein any additional tract or tracts regarded as reasonably necessary or advisable for the purposes of this agreement, or shall be contracted to exclude lands not within any participating area whenever such expansion or contraction is necessary or advisable to conform with the purposes of this agreement. Such expansion or contraction shall be effected in the following manner:

(a) Unit Operator, on its own motion, or on demand of the Director, shall prepare a notice of proposed expansion or contraction describing the contemplated changes in the boundaries of the unit area, the reasons therefor, and the proposed effective date thereof, preferably the first day of a month subsequent to the date of notice.

(b) Said notice shall be delivered to the Director and copies thereof mailed to the last known address of each working interest owner, lessee, and lessor whose interests are affected, advising that 30 days will be allowed for submission to the Unit Operator of any objections.

(c) Upon expiration of the 30-day period provided in the preceding item (b) hereof, Unit Operator shall file with the Director, evidence of mailing of the notice of expansion or contraction, and a copy of any objections thereto which have been filed with the Unit Operator, together with an application in sufficient number, for approval of such expansion or contraction and with appropriate joinders.

(d) After due consideration of all pertinent information, the expansion or contraction shall, upon approval by the Director become effective as of the date prescribed in the notice thereof.

(e) All legal subdivisions of unitized lands (i.e., 40 acres by

Government survey or its nearest lot or tract equivalent in instances of of irregular surveys, however, unusually large lots or tracts shall be considered in multiples of 40 acres, or the nearest aliquot equivalent thereof, for the purpose of elimination under this subsection), no parts of which are entitled to be in a participating area within five years after the first day of the month following the effective date of the first initial participating area established under this unit agreement, shall be eliminated automatically from this agreement, effective as of the first day thereafter, and such lands shall no longer be a part of the unit area and shall no longer be subject to this agreement except as provided in Paragraph 18 (g), unless at the expiration of said five-year period diligent drilling operations are in progress on unitized lands not entitled to participation, in which event all such lands shall remain subject hereto for so long as such drilling operations are continued diligently, with not more than ninety (90) days time elapsing between the completion of one such well and the commencement of the next such well, except that the time allowed between such wells shall not expire earlier than 30 days after the expiration of any period of time during which drilling operations are prevented by a matter beyond the reasonable control of Unit Operator, as set forth in the section hereof entitled "Unavoidable Delay"; provided that all legal subdivisions of lands not in a participating area and not entitled to become participating under the applicable provisions of this agreement within 10 years after the first day of the month following the effective date of said first initial participating area shall be eliminated as above specified. Determination of creditable "unavoidable delay" time shall be made by Unit Operator and subject to approval of the Director. The Unit Operator shall, within 90 days after the effective date of any elimination hereunder, describe the area so eliminated to the satisfaction of the Director and promptly notify all parties in interest.

If conditions warrant extension of the ten-year period specified in this subsection 2 (e), a single extension of not to exceed two years may be accomplished by consent of the owners of ninety percent of the current unitized working interests and sixty percent of the current unitized basic royalty interests (exclusive of the basic royalty interests of the State) on a total nonparticipating-acreage basis, respectively, with approval of the Commissioner provided such extension application is submitted to the Director not later than 60 days prior to the expiration of said ten-year period.

Any expansion of the unit area pursuant to this section which embraces lands theretofore eliminated pursuant to this subsection 2(e) shall not be considered automatic commitment or recommitment of such lands.

3. UNITIZED LAND AND UNITIZED SUBSTANCES. All land committed to this agreement shall constitute land referred to herein as "unitized land" or "land subject to this agreement". All oil and gas in any and all formations of the unitized land are unitized under the terms of this agreement and herein are called "unitized substances".

4. UNIT OPERATOR. PAN AMERICAN PETROLEUM CORPORATION, with offices at Anchorage, Alaska, is hereby designated as Unit Operator and by signature hereto as Unit Operator and as working interest owner commits to this agreement all interests in unitized substances vested in it and agrees and consents to accept the duties and obligations of Unit Operator for discovery, development and production of unitized substances as herein provided. Whenever reference is made herein to the Unit Operator, such reference means the Unit Operator acting in that capacity and not as an owner of interest in unitized substances, and the term "working interest owner" when used herein shall include or refer to Unit Operator as the owner of a working interest when such an interest is owned by it.

5. RESIGNATION OR REMOVAL OF UNIT OPERATOR. Unit Operator

shall have the right to resign at any time prior to the establishment of a participating area or areas hereunder, but such resignation shall not become effective so as to release Unit Operator from the duties and obligations of Unit Operator and terminate Unit Operator's rights as such for a period of six months after notice of intention to resign has been served by Unit Operator on all working interest owners and the Director, and until all wells then drilled hereunder are placed in a satisfactory condition for suspension or abandonment, whichever is required by the Director as to State and privately owned lands, unless a new Unit Operator shall have been selected and approved and shall have taken over and assumed the duties and obligations of Unit Operator prior to the expiration of said period.

Unit Operator shall have the right to resign in like manner and subject to like limitations, as above provided, at any time a participating area established hereunder is in existence but, in all instances of resignation or removal, until a successor Unit Operator is selected and approved as hereinafter provided, the working interest owners shall be jointly responsible for performance of the duties of Unit Operator, and shall not later than 30 days before such resignation or removal becomes effective appoint a common agent to represent them in any action to be taken hereunder.

The resignation of Unit Operator shall not release Unit Operator from any liability for any default by it hereunder occurring prior to the effective date of its resignation.

The Unit Operator may, upon default or failure in the performance of its duties or obligations hereunder be subject to removal by the same percentage vote of the owners of working interests determined in like manner as herein provided for the selection of a new Unit Operator. Such removal shall be effective upon notice thereof to the Director.

The resignation or removal of Unit Operator under this agreement

shall not terminate its right, title, or interest as the owner of a working interest or other interest in unitized substances, but upon the resignation or removal of Unit Operator becoming effective, such Unit Operator shall deliver possession of all equipment, materials, and appurtenances used in conducting the unit operations and owned by the working interest owners to the new duly qualified successor Unit Operator or to the owners thereof if no such new Unit Operator is elected, to be used for the purpose of conducting unit operations hereunder. Nothing herein shall be construed as authorizing removal of any material, equipment and appurtenances needed for the preservation of any wells.

6. SUCCESSOR UNIT OPERATOR. Whenever the Unit Operator shall tender his or its resignation as Unit Operator, or shall be removed as hereinabove provided, or a change of Unit Operator is negotiated by working interest owners, the owners of the working interests in the participating area or areas according to their respective acreage interests in such participating area or areas, or until a participating area shall have been established, the owners of the working interests according to their respective acreage interests in all unitized land, shall by majority vote select a successor Unit Operator; provided that, if a majority but less than 75 percent of the working interests qualified to vote are owned by one party to this agreement, a concurring vote of one or more additional working interest owners shall be required to select a new operator. Such selection shall not become effective until:

(a) a Unit Operator so selected shall accept in writing the duties and responsibilities of Unit Operator, and

(b) the selection shall have been filed with and approved by the Director. If no successor Unit Operator is selected and qualified as herein provided, the Commissioner at his election may declare this Unit Agreement

terminated.

7. ACCOUNTING PROVISIONS AND UNIT OPERATING AGREEMENT. If the Unit Operator is not the sole owner of working interests, costs and expenses incurred by Unit Operator in conducting unit operations hereunder shall be paid and apportioned among and borne by the owners of working interests, all in accordance with the agreement or agreements entered into by and between the Unit Operator and the owners of working interests, whether one or more, separately or collectively. Any agreement or agreements entered into between the working interest owners and the Unit Operator as provided in this section, whether one or more, are herein referred to as the "Unit Operating Agreement". Such unit operating agreement shall also provide the manner in which the working interest owners shall be entitled to receive their respective proportionate and allocated share of the benefits accruing hereto in conformity with their underlying operating agreements, leases, or other independent contracts, and such other rights and obligations as between Unit Operator and the working interest owners as may be agreed upon by Unit Operator and the working interest owners; however, no such unit operating agreement shall be deemed either to modify any of the terms and conditions of this unit agreement or to relieve the Unit Operator of any right or obligation established under this unit agreement, and in case of any inconsistency or conflict between the unit agreement and the unit operating agreement, this unit agreement shall prevail. Three (3) true copies of any unit operating agreement executed pursuant to this section should be filed with the Director prior to approval of this unit agreement by the Commissioner.

8. RIGHTS AND OBLIGATIONS OF UNIT OPERATOR. Except as otherwise specifically provided herein, the exclusive right, privilege, and duty of exercising any and all rights of the parties hereto which are necessary or convenient for prospecting for, producing, storing, allocating, and

distributing the unitized substances are hereby delegated to and shall be exercised by the Unit Operator as herein provided. Acceptable evidence of title to said rights shall be deposited with said Unit Operator and, together with this agreement, shall constitute and define the rights, privileges and obligations of Unit Operator. Nothing herein, however, shall be construed to transfer title to any land or to any lease or operating agreement, it being understood that under this agreement the Unit Operator, in its capacity as Unit Operator, shall exercise the rights of possession and use vested in the parties hereto only for the purposes herein specified.

9. DISCOVERY. Inasmuch as wells capable of producing unitized substances in paying quantities (to-wit: quantities sufficient to repay the cost of drilling and producing operations, with a reasonable profit) from the Tertiary system have already been drilled and tested within the unit area, no initial test well shall be required under the terms of this agreement and it shall be considered that production is had in paying quantities under this agreement on the effective date hereof.

10. PLAN OF FURTHER DEVELOPMENT AND OPERATION. Within six months after the effective date of this unit agreement, the Unit Operator shall submit for the approval of the Director an acceptable plan of development and operation for the unitized land which, when approved by the Director, shall constitute the further drilling and operating obligations of the Unit Operator under this agreement for the period specified therein. Thereafter, from time to time before the expiration of any existing plan, the Unit Operator shall submit for the approval of the Director a plan for an additional specified period for the development and operation of the unitized land.

Any plan submitted pursuant to this section shall provide for the

exploration of the unitized area and for the diligent drilling necessary for determination of the area or areas thereof capable of producing unitized substances in paying quantities in each and every productive formation and shall be as complete and adequate as the Director may determine to be necessary for timely development and proper conservation of the oil and gas resources of the unitized area, and shall:

(a) specify the number and location of any wells to be drilled and the proposed order and time for such drilling; and,

(b) to the extent practicable, specify the operating practices regarded as necessary and advisable for the proper conservation of natural resources.

Separate plans may be submitted for separate productive zones, subject to the approval of the Director.

Said plan or plans shall be modified or supplemented when necessary to meet changed conditions, or to protect the interests of all parties to this agreement. Reasonable diligence shall be exercised in complying with the obligations of the approved plan of development. The Director is authorized to grant a reasonable extension of the six-month period herein prescribed for submission of an initial plan of development where such action is justified because of unusual conditions or circumstances. After completion hereunder of a well capable of producting unitized substances in paying quantities, no further wells, except such as may be necessary to afford protection against operations not under this agreement or such as may be specifically approved by the Director shall be drilled except in accordance with a plan of development approved as herein provided.

11. PARTICIPATION AFTER DISCOVERY. Within sixty (60) days after the effective date of this unit agreement, the Unit Operator shall submit for approval by the Director a schedule based on subdivisions of the public land

survey or aliquot parts thereof of all unitized land then regarded as reasonably proved to be productive of unitized substances in paying quantities; all lands in said schedule on approval of the Director are to constitute a participating area, effective as of the effective date of the unit agreement. The acreages of both State and non-State lands shall be based upon approved protraction diagrams or appropriate computations from the courses and distances shown on the last approved protraction diagram or public land survey as of the effective date of the initial participating area or computed with reference to the last approved protraction survey or grids. Said schedule also shall set forth the percentage of unitized substances to be allocated as herein provided to each unitized tract in the participating area so established and shall govern the allocation of production from and after the date the participating area becomes effective. A separate participating area shall be established in like manner for each separate pool or deposit of unitized substances or for any group thereof produced as a single pool or zone, effective as of the date of completion of a well capable of producing unitized substances in paying quantities therefrom, and any two or more participating areas so established may be combined into one with the consent of the owners of all working interests in the lands within the participating areas so to be combined, on approval of the Director. The participating area or areas so established shall be revised from time to time, subject to like approval, whenever such action appears proper as a result of further drilling operations or otherwise, to include additional land then regarded as reasonably proved to be productive in paying quantities, or to exclude land then regarded as reasonably proved not to be productive in paying quantities and the percentage of allocation shall also be revised accordingly. The effective date of any revision shall be the first of the month in which is obtained the knowledge or information on which such revision is predicated, provided, however, that a more appropriate effective

date may be used if justified by the Unit Operator and approved by the Director. No land shall be excluded from a participating area on account of depletion of the unitized substances.

It is the intent of this section that a participating area shall represent the area known or reasonably estimated to be productive in paying quantities; but, regardless of any revision of the participating area, nothing herein contained shall be construed as requiring any retroactive adjustment for production obtained prior to the effective date of the revision of the participating area.

In the absence of agreement at any time between the Unit Operator and the Director as to the proper definition or redefinition of a participating area, or until a participating area has, or areas have, been established as provided herein, the portion of all payments affected thereby may be impounded in a manner mutually acceptable to the owners of working interests, except royalties due the State of Alaska, which shall be determined by the Director for State lands and the amount thereof deposited, as directed by the Director, to be held as unearned money until a participating area is finally approved and then applied as earned or returned in accordance with a determination of the sum due as State royalty on the basis of such approved participating area.

Upon the request of the operator or working interest owners, the Director shall hold as confidential any engineering, geophysical, geological data including but not limited to drilling logs, daily drilling reports or any other data of like or similar nature which may be requested or required by the Director for any purpose of this agreement. This shall not apply to those items required to be submitted and to be held confidential for only a limited period of time under the oil and gas conservation regulations.

Whenever it is determined, subject to the approval of the Director, that a well drilled under this agreement is not capable of production in paying

and inclusion of the land on which it is situated in a participating area is unwarranted, production from such well shall, for the purposes of settlement among all parties other than working interest owners, be allocated to the land on which the well is located so long as such land is not within a participating area established for the pool or deposit from which such production is obtained. Settlement for working interest benefits from such a well shall be made as provided in the unit operating agreement.

12. ALLOCATION OF PRODUCTION. All unitized substances produced from each participating area established under this agreement, except any part thereof used in conformity with good operating practices within the unitized area for drilling, operating, camp and other production or development purposes, for repressuring or recycling in accordance with a plan of development approved by the Director, or unavoidably lost, shall be deemed to be produced equally on an acreage basis from the several tracts of unitized land of the participating area established for such production and, for the purpose of determining any benefits accruing under this agreement, each such tract of unitized land shall have allocated to it such percentage of said production as the number of acres of such tract included in said participating area bears to the total acres of unitized land in said participating area, except that allocation of production hereunder for purposes other than for settlement of the royalty, overriding royalty, or payment out of production obligations of the respective working interest owners, shall be on the basis prescribed in the unit operating agreement whether in conformity with the basis of allocation herein set forth or otherwise. It is hereby agreed that production of unitized substances from a participating area shall be allocated as provided herein regardless of whether any wells are drilled on any particular part or tract of said participating area. If any gas produced from one participating area is used for repressuring or recycling purposes in another participating area, the first gas withdrawn from

such last-mentioned participating area for sale during the life of this agreement shall be considered to be the gas so transferred until an amount equal to that transferred shall be so produced for sale and such gas shall be allocated to the participating area from which initially produced as constituted at the time of such final production.

13. DEVELOPMENT OR OPERATION OF NON-PARTICIPATING LAND OR FORMATIONS. Any party or parties hereto owning or controlling the working interests in any unitized land having thereon a regular well location may, with the approval of the Director, and subject to the non-conflicting provisions of the unit operating agreement, at such party's or parties' sole risk, costs, and expense, drill a well at such location on such land to test any formation for which a participating area has not been established or to test any formation for which a participating area has been established if such location is not within said participating area, unless within 90 days of receipt of notice from said party of his intention to drill the well the Unit Operator elects and commences to drill such a well in like manner as other wells are drilled by the Unit Operator under this agreement.

If any well drilled as aforesaid by a working interest owner results in production such that the land upon which it is situated may properly be included in a participating area, such participating area shall be established or enlarged as provided in this agreement and the well shall thereafter be operated by the Unit Operator in accordance with the terms of this agreement and the unit operating agreement.

If any well drilled as aforesaid by a working interest owner obtains production in quantities insufficient to justify the inclusion in a participating area of the land upon which such well is situated, such well may be operated and produced by the party drilling the same subject to the conservation requirements of this agreement. The royalties in amount or value of production from

any such well shall be paid as specified in the underlying lease and agreements affected.

14. ROYALTY SETTLEMENT. The State of Alaska and all royalty owners who, under existing contract, are entitled to take in kind a share of the substances now unitized hereunder produced from any tract, shall hereafter be entitled to the right to take in kind their share of the unitized substances allocated to such tract, and Unit Operator, or in case of the operation of a well by a working interest owner as herein in special cases provided for, such working interest owner, shall make deliveries of such royalty share taken in kind in conformity with the applicable contracts, laws and regulations. Settlement for royalty interest not taken in kind shall be made by working interest owners responsible therefor under existing contracts, laws and regulations on or before the last day of each month for unitized substances produced during the preceding calendar month; provided, however, that nothing herein contained shall operate to relieve the lessees of any land from their respective lease obligations for the payment of any royalties due under their leases. No deduction for dehydration and cleaning charges shall be charged to the State's royalty except where royalty is taken in kind unless the State subsequently agrees to such deductions as reasonable and proper. Approved

If gas obtained from lands not subject to this agreement is introduced into any participating area hereunder, for use in repressuring, stimulation of production, or increasing ultimate recovery, which shall be in conformity with a plan first approved by the Director, a like amount of gas, after settlement as herein provided for any gas transferred from any other participating area and with due allowance for loss or depletion from any cause, may be withdrawn from the formation into which the gas was introduced, royalty free as to dry gas, but not as to the products extracted therefrom; provided that such withdrawal shall be at such time as may be provided in the plan of operations or as may otherwise be consented to by Director as conforming to good petroleum engineering practice; and provided further that such right of withdrawal shall terminate on the termination of this unit agreement.

Royalty due on account of the State of Alaska shall be computed and paid as to all unitized substances on the basis of the amounts allocated to such lands, and in accordance with appropriate statutes and regulations.

15. RENTAL SETTLEMENT. Rental or minimum royalties due on leases committed hereto shall be paid by working interest owners responsible therefor under existing contracts, laws, and regulations, provided that nothing herein contained shall operate to relieve the lessees of any land from their respective lease obligations for the payment of any rental or minimum royalty in lieu thereof due under their leases.

Rentals or minimum royalty on State of Alaska lands subject to this agreement shall be paid at the rates specified in the respective leases and in accordance with appropriate statutes and regulations.

With respect to any lease on non-State land containing provisions which would terminate such lease unless drilling operations were within the time therein specified commenced upon the land covered thereby or rentals paid for the privilege of deferring such drilling operations, the rentals required thereby shall, notwithstanding any other provision of this agreement, be deemed to accrue and become payable during the term thereof as extended by this agreement and thereafter until the required drilling operations are commenced upon the land covered thereby or some portion of such land is included within a participating area.

16. CONSERVATION. Operations hereunder and production of unitized substances shall be conducted to provide for the most economical and efficient recovery of said substances without waste, as defined by or pursuant to State law or regulation.

17. DRAINAGE. The Unit Operator shall take appropriate and adequate

measures to prevent drainage of unitized substances from unitized land by wells on land not subject to this agreement, or, with prior consent of the Director, pursuant to applicable regulations, pay a fair and reasonable compensatory royalty as determined by and approved by the Director for State lands leases.

18. LEASES AND CONTRACTS CONFORMED AND EXTENDED. The terms, conditions and provisions of all leases, subleases and other contracts relating to exploration, drilling, development or operation for oil and gas on lands committed to this agreement are hereby expressly modified and amended to the extent necessary to make the same conform to the provisions hereof, but otherwise to remain in full force and effect; and the parties hereto hereby consent that the Director as to State leases shall and, by his approval hereof or by the approval hereof by his duly authorized representative, does hereby establish, alter, change or revoke the drilling, producing, rental, minimum royalty, and royalty requirements of State leases committed hereto and the regulations in respect thereto and conform said requirements to the provisions of this agreement and, without limiting the generality of the foregoing, all leases, subleases, and contracts are particularly modified in accordance with the following:

(a) The development and operation of lands subject to this agreement under the terms hereof shall be deemed full performance of all obligations for development and operation with respect to each and every part or separately owned tract subject to this agreement, regardless of whether there is any development of any particular part or tract of the unit area, notwithstanding anything to the contrary in any lease, operating agreement or other contract by and between the parties hereto, or their respective predecessors in interest, or any of them.

(b) Drilling and producing operations performed hereunder upon any tract of unitized lands will be accepted and deemed to be performed

upon and for the benefit of each and every tract of unitized land, and no lease shall be deemed to expire by reason of failure to drill or produce wells situated on the land therein embraced.

(c) Suspension of drilling or producing operations on all unitized lands pursuant to direction or consent of the Commissioner or his duly authorized representative, shall be deemed to constitute such suspension pursuant to such direction or consent as to each and every tract of unitized land.

(d) Each lease, sublease or contract relating to the exploration, drilling, development or operation for oil or gas of lands, other than those of the State of Alaska, committed to this agreement, which, by its terms might expire prior to the termination of this agreement, is hereby extended beyond any such term so provided therein so that it shall be continued in full force and effect for and during the term of this agreement.

(e) Any lease embracing lands of the State of Alaska which are made subject to this agreement, shall continue in force beyond the term provided therein as to the lands committed so long as such lease remains subject hereto, provided that production is had in paying quantities under this unit agreement prior to the expiration date of the term of such lease or, in the event actual drilling operations are commenced on unitized land, in accordance with the provisions of this agreement, prior to the end of the primary term of such lease and are being diligently prosecuted at that time, such lease shall be extended for two years and so long thereafter as oil or gas is produced in paying quantities.

(f) Any lease embracing land of the State of Alaska having only a portion of its lands committed hereto, shall be segregated as to the portion committed and the portion not committed, and the provisions of such lease shall apply separately to such segregated portions commencing as of the

effective date hereof; provided, however, not withstanding any of the provisions of this agreement to the contrary, any lease embracing lands of the State of Alaska having only a portion of its lands committed hereto shall continue in full force and effect beyond the term provided therein as to all lands embraced in such lease if oil or gas is discovered and is capable of being produced in paying quantities from some part of the land embraced in such lease at the time of approval of the unit agreement by the State of Alaska or if at the time of approval of the unit agreement by the State the lessee or the Unit Operator is then engaged in bona fide drilling or reworking operations on some part of the lands embraced in such lease, the same as to all lands embraced therein shall remain in full force and effect so long as such operations are being diligently prosecuted, and if they result in the production of oil or gas in paying quantities, said lease shall continue in full force and effect as to all of the lands embraced therein so long thereafter as oil or gas in paying quantities is being produced from any portion of said leases; provided, however, that any such lease as to the non-unitized portion shall continue in force and effect for the term thereof, but for not less than two years from the date of such segregation and so long thereafter as oil or gas is produced in paying quantities.

Any State lease having production in paying quantities, as defined in this agreement, on said lease prior to comitment to this agreement shall not be segregated. The non-unitized portion shall not participate in the unit area but shall be extended by virtue of the production on the unitized portion and so long as it produces in paying quantities. Nothing herein shall operate to excuse further development on the portion lying outside the unit area where the circumstances would require a reasonably prudent lessee to further develop.

(g) Where some portion of a lease is included within the final participating area as provided in Paragraph 2(e) of this agreement, the following shall apply as to the area of the lease not so included: That area of lease lands not so included in the final participating area shall be elimi-

nated as in Paragraph 2(e) of this agreement and shall terminate after the expiration of 90 days unless annual rentals at the rate specified in the original lease shall have been paid within the said 90 days. The entire lease shall continue in force and effect so long thereafter as production is allocated to a portion of said lease and so long as annual rentals are paid on the portion not within the participating area. The first rental payment is due and payable on the first day after the expiration of the above mentioned 90 day period with allowance for proration of rentals. Thereafter, annual rentals are due and payable on the anniversary date of the lease.

19. COVENANTS RUN WITH LAND. The covenants herein shall be construed to be covenants running with the land with respect to the interest of the parties hereto and their successors in interest until this agreement terminates, and any grant, transfer or conveyance of interest in land or leases subject hereto shall be and hereby is conditioned upon the assumption of all privileges and obligations hereunder by the grantee, transferee or other successor in interest. No assignment or transfer of any working interest, royalty or other interest subject hereto shall be binding upon Unit Operator until the first day of the calendar month after Unit Operator is furnished with the original, photostatic or certified copy of the instrument of transfer.

20. EFFECTIVE DATE AND TERM. This agreement shall become effective upon approval by the Commissioner or his duly authorized representative as of the date of approval by the Commissioner and shall terminate five (5) years from said effective date unless:

(a) such date of expriation is extended by the Commissioner, or

(b) it is reasonably determined prior to the expiration of the fixed term or any extension thereof that the unitized land is incapable of production of unitized substances in paying quantities in the formations tested here-

under and after notice of intention to terminate the agreement on such ground is given by the Unit Operator to all parties in interest at their last known addresses, the agreement is terminated with the approval of the Commissioner, or

(c) a valuable discovery of unitized substances has been made or accepted on unitized land during said initial term or any extension thereof, in which event the agreement shall remain in effect for such term and so long thereafter as unitized substances can be produced in quantities sufficient to pay for the cost of producing same from wells on unitized land within any participating area established hereunder and, should production cease, so long thereafter as diligent operations are in progress for the restoration of production or discovery of new production and so long thereafter as the unitized substances so discovered can be produced as aforesaid, or

(d) it is terminated as provided in this agreement.

This agreement may be terminated at any time by not less than 75 per centum, on an acreage basis, of the owners of working interests signatory hereto, with the approval of the Commissioner; notice of any such approval to be given by the Unit Operator to all parties hereto.

21. RATE OF PROSPECTING, DEVELOPMENT AND PRODUCTION. The Director is hereby vested with authority to alter or modify from time to time in his discretion the quantity and rate of production under this agreement when such quantity and rate is not fixed pursuant to State law or does not conform to any state-wide voluntary conservation or allocation program which is established, recognized and generally adhered to by the majority of operators in such State, such authority being hereby limited to alteration or modification in the public interest, the purpose thereof and thepublic interest to be served thereby to be stated in the order of alteration or modification. Without

regard to the foregoing, the Director is also hereby vested with authority to alter or modify from time to time at his discretion the rate of prospecting and development and the quantity and rate of production under this agreement when such alteration or modification is in the interest of attaining the conservation objectives stated in this agreement and is not in violation of any applicable State law.

Powers in this section vested in the Director shall only be exercised after notice to Unit Operator and opportunity for hearing to be held not less than fifteen (15) days from notice.

22. APPEARANCES. Unit Operator shall, after notice to other parties affected, have the right to appear for and on behalf of any and all interests affected hereby before the Commissioner of the Department of Natural Resources of the State of Alaska and to appeal from orders issued under the regulations of said Department, or to apply for relief from any of said regulations or in any procedings relative to operations before the Commissioner or any other legally constituted authority; provided, however, that any other interested party shall also have the right at his own expense to be heard in any such proceeding.

23. NOTICES. All notices, demands or statements required hereunder to be given or rendered to the parties hereto shall be deemed fully given if given in writing and personally delivered to the party or sent by postpaid registered mail or certified mail, addressed to such party or parties at their respective addresses set forth in connection with the signatures hereto or the ratification or consent hereof or to such other address as any such party may have furnished in writing to the party sending the notice, demand or statement.

24. NO WAIVER OF CERTAIN RIGHTS. Nothing in this agreement contained shall be construed as a waiver by any party hereto of the right to assert

any legal or constitutional right or defense as to the validity or invalidity of any law of the State or of the United States, or regulations issued thereunder in any way affecting such party, or as a waiver by any such party of any right beyond his or its authority to waive.

25. UNAVOIDABLE DELAY. All obligations under this agreement requiring the Unit Operator to commence or continue drilling or to operate on or produce unitized substances from any of the lands covered by this agreement shall be suspended while, but only so long as, the Unit Operator despite the exercise of due care and diligence is prevented from complying with such obligations, in whole or in part, by strikes, acts of God, action of the elements, weather or natural phenomena including but not limited to ice within the unit area rendering continued operations hazardous to life or property, Federal, State or Municipal law or agencies, unavoidable accidents, uncontrollable delays in transportation, inability to obtain necessary materials in open market, or other matters beyond the reasonable control of the Unit Operator whether similar to matters herein enumerated or not.

26. NONDISCRIMINATION. In connection with the performance of work under this agreement, the operator agrees to comply with all of the provisions of Section 202 (1) to (7) inclusive, of Executive Order 11246 (30 F.R. 12319), which are hereby incorporated by reference into this agreement.

27. LOSS OF TITLE. In the event title to any tract of unitized land shall fail and the true owner cannot be induced to join in this unit agreement, such tract shall be automatically regarded as not committed hereto and there shall be such readjustment of future costs and benefits as may be required on account of the loss of such title. In the event of a dispute as to title as to any royalty, working interest or other interests subject thereto, payment or delivery on account thereof may be withheld without liability for interest

until the dispute is finally settled; provided that, as to State land or leases, no payments of funds due the State of Alaska should be withheld, but such funds of the State of Alaska shall be deposited as directed by the Commissioner, to be held as unearned money pending final settlement of the title dispute, and then applied as earned or returned in accordance with such final settlement.

Unit Operator as such is relieved from any responsibility for any defect or failure of any title hereunder.

28. NON-JOINDER AND SUBSEQUENT JOINDER. If the owner of any substantial interest in a tract within the unit area fails or refuses to subscribe or consent to this agreement, the owner of the working interest in that tract may withdraw said tract from this agreement by written notice to the Director and the Unit Operator prior to the approval of this agreement by the Commissioner. Any oil or gas interests in lands within the unit area not committed hereto prior to submission of this agreement for final approval may thereafter be committed hereto by the owner or owners thereof subscribing or consenting to this agreement and, if the interest is a working interest, by the owner of such interest also subscribing to the unit operating agreement. After operations are commenced hereunder, the right of subsequent joinder, as provided in this section, by a working interest owner is subject to such requirements or approvals, if any, pertaining to such joinder, as may be provided for in the unit operating agreement. After final approval hereof, joinder by a non-working interest owner must be consented to in writing by the working interest owner committed hereto and responsible for the payment of any benefits that may accrue hereunder in behalf of such non-working interest. Joinder by any owner of a non-working interest, at any time, must be accompanied by appropriate joinder by the owner of the corresponding working interest in order for the interest to be regarded as committed hereto. Joinder to the unit agreement by a working interest owner, at any time, must be accompanied by appropriate joinder to the unit operating agreement, if more than

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one committed working interest owner is involved, in order for the interest to be regarded as committed to this unit agreement. Except as may otherwise herein be provided, subsequent joinders to this agreement shall be effective as of the first day of the month following filing with the Director of duly executed counterparts of all or any papers necessary to establish effective commitment of any tract to this agreement unless objection to such joinder is duly made within sixty (60) days by the Director.

29. COUNTERPARTS. This agreement may be executed in any number of counterparts, no one of which needs to be executed by all parties, or may be ratified or consented to by separate instrument in writing specifically referring hereto and shall be binding upon all those parties who have executed such a counterpart, ratification or consent hereto with the same force and effect as if all such parties had signed the same document and regardless of whether or not it is executed by all other parties owning or claiming an interest in the lands within the above-described unit area.

FIFTH REVISION OF EXHIBIT "B" EFFECTIVE DECEMBER 1, 1967

A SCHEDULE OF OWNERSHIP PERTAINING TO THE

KENAI UNIT, STATE OF ALASKA

NO. 14-08-001-6367

AGO 570599

Tract No.	Description of Lands	Acres	Application or Serial No. & Effective Date of Lease	Basic Royalty Percentage	Lessee or Offeror of Record	Overriding Royalty & Percentage	Working Interest and Percentage
1	T4N, R11W, S.M. Section 5: Lot 4, = NP SW¼NW¼, = NP W½SW¼ PROTRACTED SURVEY T4N, R11W, S.M. Section 4: All (E½E½ = NP) Section 9: N½, SW¼, W½SE¼	1,359.52	A-028047 10-1-55	U.S.A. 12½%	Union Oil Company of California-50% Marathon Oil Company-50%	None	Union Oil Company of California-50% Marathon Oil Company-50%
4	T5N, R11W, S.M. Section 31: Lots 3, 4, 5, 7, 8, 10, E½ Section 32: All Section 33: All Section 34: NW¼NW¼, S½NW¼, SW¼, W½SE¼	2,044.67	A-028055 10-1-55	U.S.A. All	Do	Do	Do
5	T5N, R11W, S.M. Section 28: NW¼NW¼, S½NW¼, SW¼, W½SE¼, SE¼SE¼ Section 29: All Section 30: Lots 5, 6, 7, 8, 9, 11, 12, 13, 14, 15, E½	1,412.23	A-028056 10-1-55	Do	Do	Do	Do
14	T4N, R11W, S.M. Section 17: All Section 18: Lots 1, 2, 3, 4, E½W½, E½ Section 19: Lot 1, NE¼NW¼, NE¼ Section 20: N½NW¼, SW¼NW¼	1,598.90	ADL-22330 9-1-58	State of Alaska. 12½%	Do	M.B. Kirkparick 1%	Do

AGO 570600

Tract No.	Description of Lands	Acres	Application or Serial No. & Effective Date of Lease	Basic Royalty Percentage	Lessee or Offeror of Record	Overriding Royalty & Percentage	Working Interest and Percentage
16	T5N, R11W, S.M. Section 18: SE¼SE¼	40.00	A-028103 11-1-58	U.S.A. 12½%	Union Oil Company of California-50% Marathon Oil Company-50%	M.B. Kirkpatrick 1%	Union Oil Company of California-50% Marathon Oil Company-50%
24	T5N, R11W, S.M. Section 19: Lots 7, 8, 9, 11, 15, SE¼, E½E½SE¼SW¼, SE¼NE¼ Section 20: S½, NW¼, SW¼NE¼	749.63	A-028140 11-1-58	Do	Do	Doris L. Ervin 1%	Do
26	PROTRACTED SURVEY T4N, R11W, S.M. Section 5: All Section 6: All Section 7: All Section 8: All	2,560.00	A-028142 10-1-58	Do	Do	Do	Do
27	T4N, R12W, S.M. Section 1: Lots 1, 2, 4, 5, E½E½ = NP Section 12: Lots 5 thru 18, incl., 20, E½W½E½, E½E½ (NE SE = NP) Section 13: Lots 5 thru 12, incl., Easterly 2.50 acres of Lot 15, Easterly 2.50 acres of Lot 16, E½NW¼NE¼, E½E½, E½W½SW¼NE¼, E½W½NW¼SE¼, E½SW¼NE¼, E½NW¼SE¼	785.09	A-028143 11-1-58	Do	Do	Do	Do

AGO 570601

Tract No.	Description of Lands	Acres	Application or Serial No. & Effective Date of Lease	Basic Royalty Percentage	Lessee or Offeror of Record	Overriding Royalty & Percentage	Working Interest and Percentage
38	T4N, R12W, S.M. Section 1: Lot 6	13.17	10-20-58	Pacific American Fisheries, Inc. - 12½%	Standard Oil Company of California-50% Atlantic Richfield Company -50%	None	Standard Oil Company of California-50% Atlantic Richfield Company -50%
39	T4N, R12W, S.M. Section 12: Lot 19	2.49	3-4-59	Joseph R. Fribrock 12½%	Union Oil Company of California-50% Marathon Oil Company-50%	Do	Union Oil Company of California-50% Marathon Oil Company-50%
40	T4N, R12W, S.M. Section 13: Easterly 2.50 acres of Lot 13, Easterly 2.50 acres of Lot 14	5.00	2-25-59	Paul P. Shadura, Jr. 12½%	Do	Do	Do
145	T5N, R11W, S.M. Section 17: Lot 8, NW¼SW¼, S½SW¼	159.93	10-29-58	Leo Patrick McCanna and Daisy K. McCanna 12½%	Do	Do	Do
146	T5N, R11W, S.M. Section 17: Lot 9 Section 20: NW¼NE¼	78.97	8-9-57	Richard M. Johnston-12½%	Standard Oil Company of California-50% Atlantic Richfield Company 50%	Do	Standard Oil Company of California-50% Atlantic Richfield Company 50%
147	T5N, R11W, S.M. Section 19: Lot 2, N½NE¼, SW¼NE¼	139.31	11-13-58,	Charles Steelman-12½%	Union Oil Company of California-50% Marathon Oil Company-50%	Do	Union Oil Company of California-50% Marathon Oil Company-50%

AGO 570602

	Description of Lands	Acres	Application or Serial No. & Effective Date of Lease	Basic Royalty Percentage	Lessee or Offeror of Record	Overriding Royalty & Percentage	Working Interest and Percentage
148	T5N, R11W, S.M. Section 19: Lots 10 and 12	5.14	2-18-59	Robert E. Jacobs and Carol K. Jacobs-12½%	Union Oil Company of California-50% Marathon Oil Company-50%	None	Union Oil Company of California-50% Marathon Oil Company-50%
149	T5N, R11W, S.M. Section 19: Lot 6	5.20	8-11-59	Charles E. Miller and Marjorie L. Miller - 12½%	Do	Do	Do
152	T5N, R11W, S.M. Section 30: Lots 3 and 10	26.71	2-28-59	Lottie B. Edelman and Edwin Edelman -12½%	Do	Do	Do
153	T5N, R11W, S.M. Section 30: Lot 16	5.09	3-21-59	Carl E. Johnson and Karin W. Johnson-12½%	Do	Do	Do
154	T5N, R11W, S.M. Section 31: Lot 6	5.19	3-20-59	Robert Lee Schmidt-3-1/8% Ruth M. Schmidt 9-3/8%	Do	Do	Do
155	T5N, R11W, S.M. Section 31: Lot 9	11.10	10-20-58	Pacific American Fisheries, Inc. 12½%	Standard Oil Company of California-50% Atlantic Richfield Company 50%	Do	Standard Oil Company of California-50% Atlantic Richfield Company 50%

AGO 570603

Tract No.	Description of Lands	Acres	Application or Serial No. & Effective Date of Lease	Basic Royalty Percentage	Lessee or Offeror of Record	Overriding Royalty & Percentage	Working Interest and Percentage
161	T4N, R11W, S.M. Section 16: N½NW¼, SW¼NW¼ NW¼SW¼	160.00	ADL-00460 ✓ 10-1-55	State of Alaska-All	Union Oil Company of California-50% Marathon Oil Company-50%	M. B. Kirkpatrick 1%	Union Oil Company of California-50% Marathon Oil Company-50%
160	T5N, R11W, S.M. Section 17: That portion of Kenai River lying within SW¼ and SW¼SE¼	1.10	Preference Right Lease ADL-02397 11-1-58	Ownership Undetermined	Do	Do	Do
			IN CONFLICT WITH				
			A-045097 Application 8-21-58	Do	Charles Schraier 100%	None	Charles Schraier 100%
			A-045334 Application 8-25-58	Do	Samuel Gray 100%	Do	Samuel Gray 100%
17	T5N, R11W, S.M. Section 30: All lying westerly of the coastline Section 31: All lying westerly of coastline T5N, R12W, S.M. Section 25: SE¼NE¼, E½SE¼ ✓ Section 36: E½	895.01	ADL-00588 ✓ 1-1-60	State of Alaska-All	Union Oil Company of California-50% Marathon Oil Company-50%	Do	Union Oil Company of California-50% Marathon Oil Company-50%

AGO 570604

Delivered 3-19-68

Tract No.	Description of Lands	Acres	Application or Serial No. & Effective Date of Lease	Basic Royalty Percentage	Lessee or Offeror of Record	Overriding Royalty & Percentage	Working Interest and Percentage
176	T4N, R12W, S.M. Section 1: All lying westerly of coastline Section 2: E½E½ Section 11: E½NE¼ Section 12: All lying westerly of coastline	985.33	ADL-00593 1-1-60	State of Alaska-All	Union Oil Company of California-50% Marathon Oil Company-50%	None	Union Oil Company of California-50% Marathon Oil Company-50%
177	T4N, R12W, S.M. Section 13: All of W½NE¼, E½NW¼ lying westerly of the coastline	88.92	ADL-00594 1-1-60	Do	Do	Do	Do
178	T5N, R11W, S.M. Section 19: All of the SE¼NW¼, NE¼SW¼, S½SW¼ lying westerly of coastline	100.72	ADL-02411 3-1-61	Do	Do	Do	Do
	SUMMARY		7 Federal Tracts		8,951.14 acres		or 67.6140% of unit area
			12 Patented or entered Tracts		457.30 acres		or 3.4543% of unit area
			6 State Tracts		3,828.88 acres		or 28.9225% of unit area
			* 1 Undetermined Ownership		1.10 acres		or .0083% of unit area
	TOTALS		26 Tracts		13,238.42 acres		or 100.0000%

*Due to the unresolved question of navigability, the rightful ownership of all inland water bodies, except surveyed Sections 16 and 36 (State School Lands) is undetermined. Due to preference right filings per PL 85-505, most such tracts in this unit have conflicting applications and Federal and/or State preference right applications on file. Prior to July 1, 1967 rental and/or royalty payments for such lands were made to appropriate Federal agencies. Subsequent to that date, by agreement, payments were made to the State.

AGO 570605

Unit Agreement

for the

DEVELOPMENT AND OPERATION

of the

KENAI UNIT AREA

THIRD JUDICIAL DIVISION

STATE OF ALASKA

I-Sec. No. 14-08-001-6367

Dated May 1, 1959

AGO 570606

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Exhibits

A.	Map showing the Unit Area and the boundaries and identity of tracts and leases within Unit Area.
B.	Schedule of ownership of interests in land within Unit Area.
C.	Certification-Determination Director, Division of Lands, State of Alaska
D.	Certification-Determination Director, United States Geological Survey

UNIT AGREEMENT
FOR THE DEVELOPMENT AND OPERATION
of the
KENAI UNIT AREA
THIRD JUDICIAL DIVISION
STATE OF ALASKA

THIS AGREEMENT, entered into as of the first day of May, 1959, by and between the parties subscribing, ratifying, or consenting hereto, and herein referred to as the "parties hereto,"

WITNESSETH:

WHEREAS the parties hereto are the owners of working, royalty, or other oil and gas interests in the unit area subject to this agreement; and

WHEREAS the Mineral Leasing Act of February 25, 1920, 41 Stat. 437, as amended, 30 U. S. C. Secs. 181 et seq., authorizes Federal lessees and their representatives to unite with each other, or jointly or separately with others, in collectively adopting and operating a cooperative or unit plan of development or operation of any oil or gas pool, field, or like area, or any part thereof for the purpose of more properly conserving the natural resources thereof whenever determined and certified by the Secretary of the Interior to be necessary or advisable in the public interest; and

WHEREAS the parties hereto hold sufficient interests in the Kenai Unit Area covering the land hereinafter described to give reasonably effective control of operations therein; and

WHEREAS, it is the purpose of the parties hereto to conserve natural resources, prevent waste, and secure other benefits obtainable through development and operation of the area subject to this agreement under the terms, conditions, and limitations herein set forth;

NOW, THEREFORE, in consideration of the premises and the promises herein contained, the parties hereto commit to this agreement their respective interests in the below-defined unit area, and agree severally among themselves as follows:

1. ENABLING ACT AND REGULATIONS. The Mineral Leasing Act of February 25, 1920, as amended, supra, and all valid pertinent regulations, including operating and unit plan regulations, heretofore issued thereunder or valid, pertinent, and reasonable regulations hereafter issued thereunder are accepted and made a part of this agreement as to Federal lands, provided such regulations are not inconsistent with the terms of this agreement; and as to non-Federal lands, the oil and gas operating regulations in effect as of the effective date hereof governing drilling and producing operations, not inconsistent with the terms hereof or the laws of the State in which the non-Federal land is located, are hereby accepted and made a part of this agreement.

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2. UNIT AREA. Unit area is hereby designated and recognized as those lands included within the heavy black line on the map attached hereto marked Exhibit A and by this reference made a part hereof.

Exhibit A is a map showing the unit area and the boundaries and identity of tracts and leases in said area to the extent known to the Unit Operator. Exhibit B attached hereto is a schedule showing to the extent known to the Unit Operator the acreage, percentage, and kind of ownership of oil and gas interests in all land in the unit area. However, nothing herein or in said schedule or map shall be construed as a representation by any party hereto as to the ownership of any interest other than such interest or interests as are shown in said map or schedule as owned by such party. Exhibits A and B shall be revised by the Unit Operator whenever changes in the unit area render such revision necessary, or when requested by the Oil and Gas Supervisor, hereinafter referred to as "Supervisor" and not less than six copies of the revised exhibits shall be filed with the Supervisor.

The above-described unit area shall when practicable be expanded to include therein any additional tract or tracts regarded as reasonably necessary or advisable for the purposes of this agreement, or shall be contracted to exclude lands not within any participating area whenever such expansion or contraction is necessary or advisable to conform with the purposes of this agreement. Such expansion or contraction shall be effected in the following manner:

(a) Unit Operator, on its own motion or on demand of the Director of the Geological Survey, hereinafter referred to as "Director," after preliminary concurrence by the Director, shall prepare a notice of proposed expansion or contraction describing the contemplated changes in the boundaries of the unit area, the reasons therefor, and the proposed effective date thereof, preferably the first day of a month subsequent to the date of notice.

(b) Said notice shall be delivered to the Supervisor, and copies thereof mailed to the last known address of each working interest owner, lessee, and lessor whose interests are affected, advising that 30 days will be allowed for submission to the Unit Operator of any objections.

(c) Upon expiration of the 30-day period provided in the preceding item (b) hereof, Unit Operator shall file with the Supervisor evidence of mailing of the notice of expansion or contraction and a copy of any objections thereto which have been filed with the Unit Operator, together with an application in sufficient number, for appproval of such expansion or contraction and with appropriate joinders.

(d) After due consideration of all pertinent information, the expansion or contraction shall, upon approval by the Director, become effective as of the date prescribed in the notice thereof.

(e) All legal subdivisions of unitized lands (i.e., 40 acres by Government survey or its nearest lot or tract equivalent in instances of irregular surveys, however, unusually large lots or tracts shall be considered in multiples of 40 acres, or the nearest aliquot equivalent thereof, for the purpose of elimination under this subsection), no parts of which are entitled to be in a participating area within 5 years after the first day of the month following the effective date of the first initial participating area established under this unit agreement, shall be eliminated automatically from this agreement, effective as of the first day thereafter, and such lands shall no longer be a part of the unit area and shall no longer be subject to the agreement, unless at the expiration of said 5-year period diligent drilling operations are in progress on unitized lands not entitled to participation, in which event all such lands shall remain subject hereto for so long as such drilling operations are continued diligently, with not more than 90 days' time elapsing between the completion of one such well and the commencement of the next such well, except that the time allowed between such wells shall not expire earlier than 30 days after the expiration of any period of time during which drilling operations are prevented by a matter beyond the reasonable control of unit operator as set forth in the section hereof entitled "Unavoidable Delay"; provided that all legal subdivisions of lands not in a participating area and not entitled to become participating under the applicable provisions of this agreement within 10 years after said first day of the month following the effective date of said first initial participating area shall be eliminated as above specified. Determination of creditable "Unavoidable Delay" time shall be made by unit operator and subject to approval of the Director. The unit operator shall, within 90 days after the effective date of any elimination hereunder, describe the area so eliminated to the satisfaction of the Director and promptly notify all parties in interest.

If conditions warrant extension of the 10-year period specified in this subsection 2(e), a single extension of not to exceed 2 years may be accomplished by consent of the owners of 90% of the current unitized working interests and 60% of the current unitized basic royalty interests (exclusive of the basic royalty interests of the United States), on a total-nonparticipating-acreage basis, respectively, with approval of the Director, provided such extension application is submitted to the Director not later than 60 days prior to the expiration of said 10-year period.

Any expansion of the unit area pursuant to this section which embraces lands theretofore eliminated pursuant to this subsection 2(e) shall not be considered automatic commitment or recommitment of such lands.

3. UNITIZED LAND AND UNITIZED SUBSTANCES. All land committed to this agreement shall constitute land referred to herein as "unitized land" or "land subject to this agree-

ment." All oil and gas in any and all formations of the unitized land are unitized under the terms of this agreement and herein are called "unitized substances."

4. UNIT OPERATOR. Union Oil Company of California, a California corporation, is hereby designated as Unit Operator and by signature hereto as Unit Operator agrees and consents to accept the duties and obligations of Unit Operator for the discovery, development, and production of unitized substances as herein provided. Whenever reference is made herein to the Unit Operator, such reference means the Unit Operator acting in that capacity and not as an owner of interest in unitized substances, and the term "working interest owner" when used herein shall include or refer to Unit Operator as the owner of a working interest when such an interest is owned by it.

5. RESIGNATION OR REMOVAL OF UNIT OPERATOR. Unit Operator shall have the right to resign at any time prior to the establishment of a participating area or areas hereunder, but such resignation shall not become effective so as to release Unit Operator from the duties and obligations of Unit Operator and terminate Unit Operator's rights as such for a period of 6 months after notice of intention to resign has been served by Unit Operator on all working interest owners and the Director, and until all wells then drilled hereunder are placed in a satisfactory condition for suspension or abandonment whichever is required by the Supervisor, unless a new Unit Operator shall have been selected and approved and shall have taken over and assumed the duties and obligations of Unit Operator prior to the expiration of said period.

Unit Operator shall have the right to resign in like manner and subject to like limitations as above provided at any time a participating area established hereunder is in existence, but, in all instances of resignation or removal, until a successor unit operator is selected and approved as hereinafter provided, the working interest owners shall be jointly responsible for performance of the duties of Unit Operator, and shall not later than 30 days before such resignation or removal becomes effective appoint a common agent to represent them in any action to be taken hereunder.

The resignation of Unit Operator shall not release Unit Operator from any liability for any default by it hereunder occurring prior to the effective date of its resignation.

The Unit Operator may, upon default or failure in the performance of its duties or obligations hereunder, be subject to removal by the same percentage vote of the owners of working interests determined in like manner as herein provided for the selection of a new Unit Operator. Such removal shall be effective upon notice thereof to the Director.

The resignation or removal of Unit Operator under this agreement shall not terminate its

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right, title, or interest as the owner of a working interest or other interest in unitized substances, but upon the resignation or removal of Unit Operator becoming effective, such Unit Operator shall deliver possession of all equipment, materials, and appurtenances used in conducting the unit operations and owned by the working interest owners to the new duly qualified successor Unit Operator or to the owners thereof if no such new Unit Operator is elected, to be used for the purpose of conducting unit operations hereunder. Nothing herein shall be construed as authorizing removal of any material, equipment and appurtenances needed for the preservation of any wells.

6. SUCCESSOR UNIT OPERATOR. Whenever the Unit Operator shall tender his or its resignation as Unit Operator or shall be removed as hereinabove provided, the owners of the working interests in the participating area or areas according to their respective acreage interests in such participating area or areas, or, until a participating area shall have been established, the owners of the working interests according to their respective acreage interests in all unitized land, shall by majority vote select a successor Unit Operator: Provided, That, if a majority but less than 75 per cent of the working interests qualified to vote are owned by one party to this agreement, a concurring vote of one or more additional working interest owners shall be required to select a new operator. Such selection shall not become effective until

(a) a Unit Operator so selected shall accept in writing the duties and responsibilities of Unit Operator, and

(b) the selection shall have been approved by the Director. If no successor Unit Operator is selected and qualified as herein provided, the Director at his election may declare this unit agreement terminated.

7. ACCOUNTING PROVISIONS AND UNIT OPERATING AGREEMENT. If the Unit Operator is not the sole owner of working interests, costs and expenses incurred by Unit Operator in conducting unit operations hereunder shall be paid and apportioned among and borne by the owners of working interests, all in accordance with the agreement or agreements entered into by and between the Unit Operator and the owners of working interests, whether one or more, separately or collectively. Any agreement or agreements entered into between the working interest owners and the Unit Operator as provided in this section, whether one or more, are herein referred to as the "unit operating agreement." Such unit operating agreement shall also provide the manner in which the working interest owners shall be entitled to receive their respective proportionate and allocated share of the benefits accruing hereto in conformity with their underlying operating agreements, leases, or other independent contracts, and such other rights and obligations as between Unit Operator and the working interest owners as may be agreed upon by Unit Operator and the

working interest owners; however, no such unit operating agreement shall be deemed either to modify any of the terms and conditions of this unit agreement or to relieve the Unit Operator of any right or obligation established under this unit agreement, and in case of any inconsistency or conflict between the unit agreement and the unit operating agreement, this unit agreement shall prevail. Three true copies of any unit operating agreement executed pursuant to this section should be filed with the Supervisor, prior to approval of this unit agreement.

8. RIGHTS AND OBLIGATIONS OF UNIT OPERATOR. Except as otherwise specifically provided herein, the exclusive right, privilege, and duty of exercising any and all rights of the parties hereto which are necessary or convenient for prospecting for, producing, storing, allocating, and distributing the unitized substances are hereby delegated to and shall be exercised by the Unit Operator as herein provided. Acceptable evidence of title to said rights shall be deposited with said Unit Operator and, together with this agreement, shall constitute and define the rights, privileges, and obligations of Unit Operator. Nothing herein, however, shall be construed to transfer title to any land or to any lease or operating agreement, it being understood that under this agreement the Unit Operator, in its capacity as Unit Operator, shall exercise the rights of possession and use vested in the parties hereto only for the purposes herein specified.

9. WILDLIFE STIPULATION. Nothing in this unit agreement shall modify the special Federal lease stipulations applicable to the lands under the jurisdiction of the Fish and Wildlife Service, Bureau of Sport Fisheries and Wildlife.

10. DRILLING TO DISCOVERY. Within 6 months after the effective date hereof, the Unit Operator shall begin to drill an adequate test well at a location approved by the Supervisor, unless on such effective date a well is being drilled conformably with the terms hereof, and thereafter continue such drilling diligently to a depth sufficient to test the Kenai oil zones encountered in the Richfield Oil Corporation Swanson River Unit No. 1 Well or unless at a lesser depth unitized substances shall be discovered which can be produced in paying quantities (to wit: quantities sufficient to repay the costs of drilling, and producing operations, with a reasonable profit) or the Unit Operator shall at any time establish to the satisfaction of the Supervisor that further drilling of said well would be unwarranted or impracticable, provided, however, that Unit Operator shall not in any event be required to drill said well to a depth in excess of 12,000 feet. Until the discovery of a deposit of unitized substances capable of being produced in paying quantities, the Unit Operator shall continue drilling diligently one well at a time, allowing not more than 6 months between the completion of one well and the beginning of the next well, until a well capable of producing unitized substances in paying quantities is completed to the satisfaction of said Supervisor or until it is reasonably proved that

the unitized land is incapable of producing unitized substances in paying quantities in the formations drilled hereunder. Nothing in this section shall be deemed to limit the right of the Unit Operator to resign as provided in Section 5 hereof, or as requiring Unit Operator to commence or continue any drilling during the period pending such resignation becoming effective in order to comply with the requirements of this section. The Director may modify the drilling requirements of this section by granting reasonable extensions of time when, in his opinion, such action is warranted.

Upon failure to comply with the drilling provisions of this section, the Director may, after reasonable notice to the Unit Operator, and each working interest owner, lessee, and lessor at their last known addresses, declare this unit agreement terminated.

Notwithstanding anything else in this agreement to the contrary, the drilling obligations for the first three test wells or until discovery of unitized substances in paying quantities, whichever occurs earlier, shall be as specified in this paragraph. Unit Operator shall be required to commence three such test wells as follows: One within six months after approval of the unit agreement, with the understanding that any such well commenced after May 1, 1959, will be accepted, one within two years after approval hereof, and one within three years after approval hereof. Prior to discovery of unitized substances in paying quantities, failure to commence timely drilling will result in automatic termination of this unit agreement as of the first day of the thirteenth, twenty-fifth, or thirty-seventh month, respectively. As to said three wells, the Director may grant reasonable extensions of time in fulfilling the three-well drilling obligation only in event the Director determines conditions beyond the control of Unit Operator warrant. In event the first or second well discovers unitized substances in paying quantities, any remaining well of the three shall no longer be due as an exploratory test well, but all unit development after said discovery shall be under an approved plan of development. Upon completion of the three-well obligation or upon discovery of paying unit production, this paragraph shall have no further significance.

11. PLAN OF FURTHER DEVELOPMENT AND OPERATION. Within 6 months after completion of a well capable of producing unitized substances in paying quantities, the Unit Operator shall submit for the approval of the Supervisor an acceptable plan of development and operation for the unitized land which, when approved by the Supervisor, shall constitute the further drilling and operating obligations of the Unit Operator under this agreement for the period specified therein. Thereafter, from time to time before the expiration of any existing plan, the Unit Operator shall submit for the approval of the Supervisor a plan for an additional specified period for the development and operation of the unitized land. Any plan submitted pursuant to this section shall provide for the exploration of the unitized area and for the diligent drilling necessary for determination of the area or areas thereof capable of producing unitized substances in paying quantities in each

and every productive formation and shall be as complete and adequate as the Supervisor may determine to be necessary for timely development and proper conservation of the oil and gas resources of the unitized area and shall

(a) specify the number and locations of any wells to be drilled and the proposed order and time for such drilling; and

(b) to the extent practicable specify the operating practices regarded as necessary and advisable for proper conservation of natural resources. Separate plans may be submitted for separate productive zones, subject to the approval of the Supervisor. Said plan or plans shall be modified or supplemented when necessary to meet changed conditions or to protect the interests of all parties to this agreement. Reasonable diligence shall be exercised in complying with the obligations of the approved plan of development. The Supervisor is authorized to grant a reasonable extension of the 6-month period herein prescribed for submission of an initial plan of development where such action is justified because of unusual conditions or circumstances. After completion hereunder of a well capable of producing any unitized substance in paying quantities, no further wells, except such as may be necessary to afford protection against operations not under this agreement or such as may be specifically approved by the Supervisor, shall be drilled except in accordance with a plan of development approved as herein provided.

12. PARTICIPATION AFTER DISCOVERY. Upon completion of a well capable of producing unitized substances in paying quantities or as soon thereafter as required by the Supervisor, the Unit Operator shall submit for approval by the Director a schedule, based on subdivisions of the public-land survey or aliquot parts thereof, of all unitized land then regarded as reasonably proved to be productive of unitized substances in paying quantities; all lands in said schedule on approval of the Director to constitute a participating area, effective as of the date of completion of such well or the effective date of the unit agreement, whichever is later. Said schedule also shall set forth the percentage of unitized substances to be allocated as herein provided to each unitized tract in the participating area so established, and shall govern the allocation of production from and after the date the participating area becomes effective. A separate participating area shall be established in like manner for each separate pool or deposit of unitized substances or for any group thereof produced as a single pool or zone, and any two or more participating areas so established may be combined into one with the consent of the owners of all working interests in the lands within the participating areas so to be combined, on approval of the Director. The participating area or areas so established shall be revised from time to time, subject to like approval, whenever such action appears proper as a result of further drilling operations or otherwise, to include additional land then regarded as reasonably proved to be productive in paying quantities, or to exclude land then regarded

as reasonably proved not to be productive in paying quantities and the percentage of allocation shall also be revised accordingly. The effective date of any revision shall be the first of the month in which is obtained the knowledge or information on which such revision is predicated, provided, however, that a more appropriate effective date may be used if justified by the Unit Operator and approved by the Director. No land shall be excluded from a participating area on account of depletion of the unitized substances.

It is the intent of this section that a participating area shall represent the area known or reasonably estimated to be productive in paying quantities; but, regardless of any revision of the participating area, nothing herein contained shall be construed as requiring any retroactive adjustment for production obtained prior to the effective date of the revision of the participating area.

In the absence of agreement at any time between the Unit Operator and the Director as to the proper definition or redefinition of a participating area, or until a participating area has, or areas have, been established as provided herein, the portion of all payments affected thereby may be impounded in a manner mutually acceptable to the owners of working interests, except royalties due the United States, which shall be determined by the Supervisor and the amount thereof deposited, as directed by the Supervisor, to be held as unearned money until a participating area is finally approved and then applied as earned or returned in accordance with a determination of the sum due as Federal royalty on the basis of such approved participating area.

Whenever it is determined, subject to the approval of the Supervisor, that a well drilled under this agreement is not capable of production in paying quantities and inclusion of the land on which it is situated in a participating area is unwarranted, production from such well shall, for the purposes of settlement among all parties other than working interest owners, be allocated to the land on which the well is located so long as such land is not within a participating area established for the pool or deposit from which such production is obtained. Settlement for working interest benefits from such a well shall be made as provided in the unit operating agreement.

13. ALLOCATION OF PRODUCTION. All unitized substances produced from each participating area established under this agreement, except any part thereof used in conformity with good operating practices within the unitized area for drilling, operating, camp and other production or development purposes, for repressuring or recycling in accordance with a plan of development approved by the Supervisor, or unavoidably lost, shall be deemed to be produced equally on an acreage basis from the several tracts of unitized land of the participating area established for such production and, for the purpose of determining any benefits accruing under this agreement, each such tract of unitized land shall have allocated to it such percentage of said production as the num-

ber of acres of such tract included in said participating area bears to the total acres of unitized land in said participating area, except that allocation of production hereunder for purposes other than for settlement of the royalty, overriding royalty, or payment out of production obligations of the respective working interest owners, shall be on the basis prescribed in the unit operating agreement whether in conformity with the basis of allocation herein set forth or otherwise. It is hereby agreed that production of unitized substances from a participating area shall be allocated as provided herein regardless of whether any wells are drilled on any particular part or tract of said participating area. If any gas produced from one participating area is used for repressuring or recycling purposes in another participating area, the first gas withdrawn from such last-mentioned participating area for sale during the life of this agreement shall be considered to be the gas so transferred until an amount equal to that transferred shall be so produced for sale and such gas shall be allocated to the participating area from which initially produced as constituted at the time of such final production.

14. DEVELOPMENT OR OPERATION OF NON-PARTICIPATING LAND OR FORMATIONS. Any party hereto owning or controlling the working interest in any unitized land having thereon a regular well location may with the approval of the Supervisor, at such party's sole risk, costs, and expense, drill a well to test any formation for which a participating area has not been established or to test any formation for which a participating area has been established if such location is not within said participating area, unless within 90 days of receipt of notice from said party of his intention to drill the well the Unit Operator elects and commences to drill such a well in like manner as other wells are drilled by the Unit Operator under this agreement.

If any well drilled as aforesaid by a working interest owner results in production such that the land upon which it is situated may properly be included in a participating area, such participating area shall be established or enlarged as provided in this agreement and the well shall thereafter be operated by the Unit Operator in accordance with the terms of this agreement and the unit operating agreement.

If any well drilled as aforesaid by a working interest owner obtains production in quantities insufficient to justify the inclusion in a participating area of the land upon which such well is situated, such well may be operated and produced by the party drilling the same subject to the conservation requirements of this agreement. The royalties in amount or value of production from any such well shall be paid as specified in the underlying lease and agreements affected.

15. ROYALTY SETTLEMENT. The United States and any State and all royalty owners who, under existing contract, are entitled to take in kind a share of the substances now unitized hereunder

produced from any tract, shall hereafter be entitled to the right to take in kind their share of the unitized substances allocated to such tract, and Unit Operator, or in case of the operation of a well by a working interest owner as herein in special cases provided for, such working interest owner, shall make deliveries of such royalty share taken in kind in conformity with the applicable contracts, laws, and regulations. Settlement for royalty interest not taken in kind shall be made by working interest owners responsible therefor under existing contracts, laws and regulations on or before the last day of each month for unitized substances produced during the preceding calendar month; provided, however, that nothing herein contained shall operate to relieve the lessees of any land from their respective lease obligations for the payment of any royalties due under their leases

If gas obtained from lands not subject to this agreement is introduced into any participating area hereunder, for use in repressuring, stimulation of production, or increasing ultimate recovery, which shall be in conformity with a plan first approved by the Supervisor, a like amount of gas, after settlement as herein provided for any gas transferred from any other participating area and with due allowance for loss or depletion from any cause, may be withdrawn from the formation into which the gas was introduced, royalty free as to dry gas, but not as to the products extracted therefrom; provided that such withdrawal shall be at such time as may be provided in the plan of operations or as may otherwise be consented to by the Supervisor as conforming to good petroleum engineering practice; and provided further, that such right of withdrawal shall terminate on the termination of this unit agreement.

If liquefied petroleum gases obtained from lands or formations not subject to this agreement be injected into the unitized land for the purpose of increasing ultimate recovery, which shall be in conformance with a plan first approved by the Supervisor, part or all of such liquefied petroleum gases may be withdrawn royalty free pursuant to such conditions and formulas as may be prescribed or approved by the Supervisor.

Royalty due the United States shall be computed as provided in the operating regulations and paid in value or delivered in kind as to all unitized substances on the basis of the amounts thereof allocated to unitized Federal land as provided herein at the rates specified in the respective Federal leases, or at such lower rate or rates as may be authorized by law or regulation; provided, that for leases on which the royalty rate depends on the daily average production per well, said average production shall be determined in accordance with the operating regulations as though each participating area were a single consolidated lease.

16. RENTAL SETTLEMENT. Rental or minimum royalties due on leases committed hereto shall be paid by working interest owners responsible therefor under existing contracts, laws, and regulations, provided that nothing herein contained shall operate to relieve the lessees of any land

from their respective lease obligations for the payment of any rental or minimum royalty in lieu thereof due under their leases. Rental or minimum royalty for lands of the United States subject to this agreement shall be paid at the rate specified in the respective leases from the United States unless such rental or minimum royalty is waived, suspended, or reduced by law or by approval of the Secretary or his duly authorized representative.

With respect to any lease on non-Federal land containing provisions which would terminate such lease unless drilling operations were within the time therein specified commenced upon the land covered thereby or rentals paid for the privilege of deferring such drilling operations, the rentals required thereby shall, notwithstanding any other provision of this agreement, be deemed to accrue and become payable during the term thereof as extended by this agreement and until the required drilling operations are commenced upon the land covered thereby or some portion of such land is included within a participating area.

17. CONSERVATION. Operations hereunder and production of unitized substances shall be conducted to provide for the most economical and efficient recovery of said substances without waste, as defined by or pursuant to State or Federal law or regulation.

18. DRAINAGE. The Unit Operator shall take appropriate and adequate measures to prevent drainage of unitized substances from unitized land by wells on land not subject to this agreement, or pursuant to applicable regulations pay a fair and reasonable compensatory royalty as determined by the Supervisor.

19. LEASES AND CONTRACTS CONFORMED AND EXTENDED. The terms, conditions, and provisions of all leases, subleases, and other contracts relating to exploration, drilling, development, or operation for oil or gas of lands committed to this agreement are hereby expressly modified and amended to the extent necessary to make the same conform to the provisions hereof, but otherwise to remain in full force and effect; and the parties hereto hereby consent that the Secretary shall and by his approval hereof, or by the approval hereof by his duly authorized representative, does hereby establish, alter, change, or revoke the drilling, producing, rental, minimum royalty, and royalty requirements of Federal leases committed hereto and the regulations in respect thereto to conform said requirements to the provisions of this agreement, and, without limiting the generality of the foregoing, all leases, subleases, and contracts are particularly modified in accordance with the following:

(a) The development and operation of lands subject to this agreement under the terms hereof shall be deemed full performance of all obligations for development and operation with respect to each and every part or separately owned tract subject to this agreement, regard-

less of whether there is any development of any particular part or tract of the unit area, notwithstanding anything to the contrary in any lease, operating agreement or other contract by and between the parties hereto, or their respective predecessors in interest, or any of them.

(b) Drilling and producing operations performed hereunder upon any tract of unitized lands will be accepted and deemed to be performed upon and for the benefit of each and every tract of unitized land, and no lease shall be deemed to expire by reason of failure to drill or produce wells situated on the land therein embraced.

(c) Suspension of drilling or producing operations on all unitized lands pursuant to direction or consent of the Secretary or his duly authorized representative shall be deemed to constitute such suspension pursuant to such direction or consent as to each and every tract of unitized land.

(d) Each lease, sublease or contract relating to the exploration, drilling, development or operation for oil or gas of lands other than those of the United States committed to this agreement, which, by its terms might expire prior to the termination of this agreement, is hereby extended beyond any such term so provided therein so that it shall be continued in full force and effect for and during the term of this agreement.

(e) Any Federal lease for a fixed term of twenty (20) years or any renewal thereof or any part of such lease which is made subject to this agreement shall continue in force beyond the term provided therein until the termination hereof. Any other Federal lease committed hereto shall continue in force beyond the term so provided therein or by law as to the land committed so long as such lease remains subject hereto, provided that production is had in paying quantities under this unit agreement prior to the expiration date of the term of such lease.

(f) Each sublease or contract relating to the operation and development of unitized substances from lands of the United States committed to this agreement, which by its terms would expire prior to the time at which the underlying lease, as extended by the immediately preceding paragraph, will expire, is hereby extended beyond any such term so provided therein so that it shall be continued in full force and effect for and during the term of the underlying lease as such term is herein extended.

(g) The segregation of any Federal lease committed to this agreement is governed by the following provision in the fourth paragraph of Sec. 17(b) of the Act, as amended by the Act of July 29, 1954 (68 Stat. 583, 585): "Any (Federal) lease hereafter committed to any such (unit) plan embracing lands that are in part within and in part outside of the area covered by any such plan shall be segregated into separate leases as to the lands com-

mitted and the lands not committed as of the effective date of unitization: Provided, however, That any such lease as to the nonunitized portion shall continue in force and effect for the term thereof but for not less than two years from the date of such segregation and so long thereafter as oil or gas is produced in paying quantities."

(h) Any lease, other than a Federal lease, having only a portion of its lands committed hereto shall be segregated as to the portion committed and the portion not committed, and the provisions of such lease shall apply separately to such segregated portions commencing as of the effective date hereof. In the event any such lease provides for a lump-sum rental payment, such payment shall be prorated between the portions so segregated in proportion to the acreage of the respective tracts.

20. COVENANTS RUN WITH LAND. The covenants herein shall be construed to be covenants running with the land with respect to the interest of the parties hereto and their successors in interest until this agreement terminates, and any grant, transfer, or conveyance, of interest in land or leases subject hereto shall be and hereby is conditioned upon the assumption of all privileges and obligations hereunder by the grantee, transferee, or other successor in interest. No assignment or transfer of any working interest, royalty, or other interest subject hereto shall be binding upon Unit Operator until the first day of the calendar month after Unit Operator is furnished with the original, photostatic, or certified copy of the instrument of transfer.

21. EFFECTIVE DATE AND TERM. This agreement shall become effective upon approval by the Secretary or his duly authorized representative and shall terminate five (5) years from said effective date unless

(a) such date of expiration is extended by the Director, or

(b) it is reasonably determined prior to the expiration of the fixed term or any extension thereof that the unitized land is incapable of production of unitized substances in paying quantities in the formations tested hereunder and after notice of intention to terminate the agreement on such ground is given by the Unit Operator to all parties in interest at their last known addresses, the agreement is terminated with the approval of the Director, or

(c) a valuable discovery of unitized substances has been made on unitized land during said initial term or any extension thereof, in which event the agreement shall remain in effect for such term and so long as unitized substances can be produced in paying quantities, i.e., in this particular instance in quantities sufficient to pay for the cost of producing same from wells on unitized land within any participating area established hereunder and, should production cease, so long thereafter as diligent operations are in progress for the restoration of

production or discovery of new production and so long thereafter as the unitized substances so discovered can be produced as aforesaid, or

(d) it is terminated as heretofore provided in this agreement.

This agreement may be terminated at any time by not less than 75 per centum, on an acreage basis, of the owners of working interest signatory hereto, with the approval of the Director; notice of any such approval to be given by the Unit Operator to all parties hereto.

22. RATE OF PROSPECTING, DEVELOPMENT, AND PRODUCTION. The Director is hereby vested with authority to alter or modify from time to time in his discretion the quantity and rate of production under this agreement when such quantity and rate is not fixed pursuant to Federal or State law or does not conform to any state-wide voluntary conservation or allocation program, which is established, recognized, and generally adhered to by the majority of operators in such State, such authority being hereby limited to alteration or modification in the public interest, the purpose thereof and the public interest to be served thereby to be stated in the order of alteration or modification. Without regard to the foregoing, the Director is also hereby vested with authority to alter or modify from time to time in his discretion the rate of prospecting and development and the quantity and rate of production under this agreement when such alteration or modification is in the interest of attaining the conservation objectives stated in this agreement and is not in violation of any applicable Federal or State law.

Powers in this section vested in the Director shall only be exercised after notice to Unit Operator and opportunity for hearing to be held not less than 15 days from notice.

23. APPEARANCES. Unit Operator shall, after notice to other parties affected, have the right to appear for and on behalf of any and all interests affected hereby before the Department of the Interior and to appeal from orders issued under the regulations of said Department or to apply for relief from any of said regulations or in any proceedings relative to operations before the Department of the Interior or any other legally constituted authority; provided, however, that any other interested party shall also have the right at his own expense to be heard in any such proceeding.

24. NOTICES. All notices, demands or statements required hereunder to be given or rendered to the parties hereto shall be deemed fully given if given in writing and personally delivered to the party or sent by postpaid registered mail, addressed to such party or parties at their respective addresses set forth in connection with the signatures hereto or to the ratification or consent hereof

or to such other address as any such party may have furnished in writing to party sending the notice, demand or statement.

25. NO WAIVER OF CERTAIN RIGHTS. Nothing in this agreement contained shall be construed as a waiver by any party hereto of the right to assert any legal or constitutional right or defense as to the validity or invalidity of any law of the State wherein said unitized lands are located, or of the United States, or regulations issued thereunder in any way affecting such party, or as a waiver by any such party of any right beyond his or its authority to waive.

26. UNAVOIDABLE DELAY. All obligations under this agreement requiring the Unit Operator to commence or continue drilling or to operate on or produce unitized substances from any of the lands covered by this agreement shall be suspended while, but only so long as, the Unit Operator despite the exercise of due care and diligence is prevented from complying with such obligations, in whole or in part, by strikes, acts of God, Federal, State, or municipal law or agencies, unavoidable accidents, uncontrollable delays in transportation, inability to obtain necessary materials in open market, or other matters beyond the reasonable control of the Unit Operator whether similar to matters herein enumerated or not.

27. FAIR EMPLOYMENT. In connection with the performance of work under this agreement, the operator agrees not to discriminate against any employee or applicant for employment because of race, religion, color, or national origin. The aforesaid provision shall include, but not be limited to, the following: employment, upgrading, demotion, or transfer; recruitment or recruitment advertising, layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The operator agrees to post hereafter in conspicuous places, available for employees and applicants for employment, notices to be provided by the contracting officer setting forth the provisions of the nondiscrimination clause.

The operator agrees to insert the foregoing provision in all subcontracts hereunder, except subcontracts for standard commercial supplies or raw materials.

28. LOSS OF TITLE. In the event title to any tract of unitized land shall fail and the true owner cannot be induced to join in this unit agreement, such tract shall be automatically regarded as not committed hereto and there shall be such readjustment of future costs and benefits as may be required on account of the loss of such title. In the event of a dispute as to title as to any royalty, working interest, or other interest subject thereto, payment or delivery on account thereof may be withheld without liability for interest until the dispute is finally settled; provided, that, as to Federal land or leases, no payments of funds due the United States should

be withheld, but such funds shall be deposited as directed by the Supervisor to be held as unearned money pending final settlement of the title dispute, and then applied as earned or returned in accordance with such final settlement.

Unit Operator as such is relieved from any responsibility for any defect or failure of any title hereunder.

29. NON-JOINDER AND SUBSEQUENT JOINDER. If the owner of any substantial interest in a tract within the unit area fails or refuses to subscribe or consent to this agreement, the owner of the working interest in that tract may withdraw said tract from this agreement by written notice to the Director and the Unit Operator prior to the approval of this agreement by the Director. Any oil or gas interests in lands within the unit area not committed hereto prior to submission of this agreement for final approval may thereafter be committed hereto by the owner or owners thereof subscribing or consenting to this agreement, and, if the interest is a working interest, by the owner of such interest also subscribing to the unit operating agreement. After operations are commenced hereunder, the right of subsequent joinder, as provided in this section, by a working interest owner is subject to such requirements or approvals, if any, pertaining to such joinder, as may be provided for in the unit operating agreement. After final approval hereof joinder by a non-working interest owner must be consented to in writing by the working interest owner committed hereto and responsible for the payment of any benefits that may accrue hereunder in behalf of such non-working interest. Joinder by any owner of a non-working interest, at any time, must be accompanied by appropriate joinder by the owner of the corresponding working interest in order for the interest to be regarded as effectively committed hereto. Joinder to the unit agreement by a working interest owner, at any time, must be accompanied by appropriate joinder to the unit operating agreement, if more than one committed working-interest owner is involved, in order for the interest to be regarded as effectively committed to this unit agreement. Except as may otherwise herein be provided subsequent joinders to this agreement shall be effective as of the first day of the month following the filing with the Supervisor of duly executed counterparts of all or any papers necessary to establish effective committment of any tract to this agreement unless objection to such joinder is duly made within 60 days by the Director.

30. COUNTERPARTS. This agreement may be executed in any number of counterparts no one of which needs to be executed by all parties or may be ratified or consented to by separate instrument in writing specifically referring hereto and shall be binding upon all those parties who have executed such a counterpart, ratification, or consent hereto with the same force and effect as if all such parties had signed the same document and regardless of whether or not it is executed by all other parties owning or claiming an interest in the lands within the unit area.

31. SURRENDER. Nothing in this agreement shall prohibit the exercise by any working interest owner of the right to surrender vested in such party in any lease, sub-lease, or operating agreement as to all or any part of the lands covered thereby, provided that each party who will or might acquire such working interest by such surrender or by forfeiture as hereafter set forth, is bound by the terms of this agreement.

If as a result of any such surrender, the working interest rights as to such lands become vested in any party other than the fee owner of the unitized substances, said party shall forfeit such rights and no further benefits from operation hereunder as to said land shall accrue to such party, unless within ninety (90) days thereafter said party shall execute this agreement and the unit operating agreement as to the working interest acquired through such surrender, effective as though such land had remained continuously subject to this agreement and the unit operating agreement. And in the event such agreements are not so executed, the party next in the chain of title shall be and become the owner of such working interest at the end of such ninety (90) day period, with the same force and effect as though such working interest had been surrendered to such party.

If as the result of any such surrender or forfeiture the working interest rights as to such lands become vested in the fee owner of the unitized substances, such owner may:

(1) Execute this agreement and the unit operating agreement as a working interest owner, effective as though such land had remained continuously subject to this agreement and the unit operating agreement.

(2) Again lease such lands but only under the condition that the holder of such lease shall within thirty (30) days after such lands are so leased execute this agreement and the unit operating agreement as to each participating area theretofore established hereunder, effective as though such land had remained continuously subject to this agreement and the unit operating agreement.

(3) Operate or provide for the operation of such land independently of this agreement as to any part thereof or any oil or gas deposits therein not then included within a participating area.

If the fee owner of the unitized substances does not execute this agreement and the unit operating agreement as a working interest owner or again lease such lands as above provided with respect to each existing participating area, within six (6) months after any such surrender or forfeiture, such fee owner shall be deemed to have waived the right to execute the unit operating agreement or lease such lands as to each such participating area, and to have agreed, in consideration for the compensation hereinafter provided, that operations hereunder as to any such participating area or areas shall not be affected by such surrender.

For any period the working interest in any lands are not expressly committed to the unit operating agreement as the result of any such surrender or forfeiture, the benefits and obligations of operations accruing to such lands under this agreement and the unit operating agreement shall be shared by the remaining owners of unitized working interests in accordance with their respective participating working interest ownerships in any such participating area or areas, and such owners of working interests shall compensate the fee owner of unitized substances in such lands by paying sums equal to the rentals, minimum royalties, and royalties applicable to such lands under the lease in effect when the lands were unitized, as to such participating area or areas.

Upon commitment of a working interest to this agreement and the unit operating agreement as provided in this section, an appropriate accounting and settlement shall be made, to reflect the retroactive effect of the commitment, for all benefits accruing to or payments and expenditures made or incurred on behalf of such surrendered working interest during the period between the date of surrender and the date of recommitment, and payment of any moneys found to be owing by such an accounting shall be made as between the parties then signatory to the unit operating agreement and this agreement within thirty (30) days after the recommitment. The right to become a party to this agreement and the unit operating agreement as a working interest owner by reason of a surrender or forfeiture as provided in this section shall not be defeated by the nonexistence of a unit operating agreement and in the event no unit operating agreement is in existence and a mutually acceptable agreement between the proper parties thereto cannot be consummated, the Supervisor may prescribe such reasonable and equitable agreement as he deems warranted under the circumstances.

Nothing in this section shall be deemed to limit the right of joinder or subsequent joinder to this agreement as provided elsewhere in this agreement. The exercise of any right vested in a working interest owner to reassign such working interest to the party from whom obtained shall be subject to the same conditions as set forth in this section in regard to the exercise of a right to surrender.

32. TAXES. The working interest owners shall render and pay for their account and the account of the royalty owners all valid taxes on or measured by the unitized substances in and under or that may be produced, gathered and sold from the land subject to this contract after the effective date of this agreement, or upon the proceeds or net proceeds derived therefrom. The working interest owners on each tract shall and may charge the proper proportion of said taxes to the royalty owners having interests in said tract, and may currently retain and deduct sufficient of the unitized substances or derivative products, or net proceeds thereof from the allocated share of each royalty owner to secure reimbursement for the taxes so paid. No such taxes shall be charged

to the United States or the State of Alaska or to any lessor who has a contract with his lessee which requires the lessee to pay such taxes.

33. NO PARTNERSHIP. It is expressly agreed that the relation of the parties hereto is that of independent contractors and nothing in this agreement contained, expressed or implied, nor any operations conducted hereunder, shall create or be deemed to have created a partnership or association between the parties hereto or any of them.

34. STATE LANDS. Certain of the lands within the unit area are public lands of the State of Alaska. In the event the State Division of Lands commits its interest in said lands, or any part thereof, to this agreement pursuant to applicable laws of Alaska and Federal Regulations 30 CFR, Section 226.7, it is agreed that such commitment and the terms and conditions incident thereto may be made by means of an Approval-Certificate-Determination, executed by said Division in such form as may be acceptable to the Director and to the Unit Operator.

IN WITNESS WHEREOF, the parties hereto have caused this agreement to be executed and have set opposite their respective names the date of execution.

UNIT OPERATOR

June 16, 1959
P. O. Box 7600
Los Angeles 54, California

UNION OIL COMPANY OF CALIFORNIA

By Dudley Tower
Vice President

By [signature]
Assistant Secretary

WORKING INTEREST OWNERS

June 16, 1959
P. O. Box 7600
Los Angeles 54, California

UNION OIL COMPANY OF CALIFORNIA

By Dudley Tower
Vice President

By [signature]
Assistant Secretary.

550 South Flower Street
Los Angeles 17, California

JUN 1 9 1959

THE OHIO OIL COMPANY

By [signature]
Vice President

By L G Edelman
Assistant Secretary

AGO 570628

State OF California
County of LOS ANGELES } ss.

On this 16th day of June, 19 59, before me, MARGARET I. YOUNG,
a Notary Public, personally appeared DUDLEY TOWER, known to me to be the
VICE President, and E. W. CAIRNS, known to me to be the ASSISTANT
Secretary, of UNION OIL COMPANY OF CALIFORNIA,
the Corporation that executed the within Instrument, known to me to be the persons who executed the within Instrument on behalf of the Corporation herein named, and acknowledged to me that such Corporation executed the within Instrument pursuant to its bylaws or a resolution of its board of directors.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal the day and year in this certificate first above written.

Margaret I. Young
Notary Public

My Commission Expires July 20, 1962

State OF Ohio
County of Hancock } ss.

On this 22 day of June, 19 59, before me, M. E. Sorenson,
a Notary Public, personally appeared Glenn F. Bish, known to me to be the
Vice President, and L. G. Edelman, known to me to be the Assistant
Secretary, of THE OHIO OIL COMPANY,
the Corporation that executed the within Instrument, known to me to be the persons who executed the within Instrument on behalf of the Corporation herein named, and acknowledged to me that such Corporation executed the within Instrument pursuant to its bylaws or a resolution of its board of directors.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal the day and year in this certificate first above written.

M. E. Sorenson
M. E. Sorenson Notary Public

My Commission Expires June 20, 1962

..... OF .....
..... of ..... } ss.

On this ..... day of ....., 19....., before me, ...,
a Notary Public, personally appeared ....., known to me to be the
..... President, and ....., known to me to be the .....
Secretary, of .....,
the Corporation that executed the within Instrument, known to me to be the persons who executed the within Instrument on behalf of the Corporation herein named, and acknowledged to me that such Corporation executed the within Instrument pursuant to its bylaws or a resolution of its board of directors.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal the day and year in this certificate first above written.

.....
Notary Public

My Commission Expires .....

AGO 570629

CERTIFICATION-DETERMINATION

Pursuant to the authority vested in the Commissioner of the Department of Natural Resources under the Alaska Land act approved April, 1959, otherwise known as Senate Bill #77, and delegated to the Director of the Division of Lands pursuant to Article II Section 5 thereof, I do hereby:

A. Approve the attached agreement for the development and operation of the Kenai Unit Area, State of Alaska.

B. Certify and determine that the unit plan of development and operation contemplated in the attached agreement is necessary and advisable in the public interest for the purpose of more properly conserving the natural resources.

C. Certify and determine that the drilling, producing, rental, minimum royalty, and royalty requirements of all leases committed to said agreement covering State of Alaska Lands are hereby established, altered, changed, or revoked to conform with the terms and conditions of this agreement.

Dated July 2, 1959

ALASKA OIL AND GAS CONSERVATION COMMISSION

Phil R. Holdsworth Commissioner.
~~Director, Division of Lands~~, State of Alaska

DEPARTMENT OF
NATURAL RESOURCES

EXHIBIT "C"

AGO 570630

CERTIFICATION-DETERMINATION

Pursuant to the authority vested in the Secretary of the Interior, under the act approved February 25, 1920, 41 Stat. 437, as amended, 30 U. S. C. secs. 181, et seq., and delegated to the Director of the Geological Survey pursuant to Departmental Order No. 2365 of October 8, 1947, 43 C. F. R. sec. 4.611, 12 F. R. 6784, I do hereby:

A. Approve the attached agreement for the development and operation of the Kenai Unit Area, State of Alaska.

B. Certify and determine that the unit plan of development and operation contemplated in the attached agreement is necessary and advisable in the public interest for the purpose of more properly conserving the natural resources.

C. Certify and determine that the drilling, producing, rental, minimum royalty, and royalty requirements of all Federal leases committed to said agreement are hereby established, altered, changed, or revoked to conform with the terms and conditions of this agreement.

Dated JUL 30 1959.

Arthur A Baker

Acting Director, United States Geological Survey

EXHIBIT "D"

AGO 570631

RECEIVED
OCT 5 1964
Conservation Division
U.S. GEOLOGICAL SURVEY
Anchorage, Alaska

A-582

AMENDMENT TO UNIT AGREEMENT

THIS AGREEMENT, made and entered into this 16th day of September, 1964, by and between the parties subscribing, ratifying, or consenting hereto, and herein referred to as the "parties hereto,"

W I T N E S S E T H :

WHEREAS, the parties hereto desire to amend that certain Unit Agreement For The Development And Operation of the Kenai Unit Area, No. 14-08-001-6367, Third Judicial Division, State of Alaska, approved effective July 30, 1959, being more particularly described therein, in order to extend the five year period which commenced on the first day of the month following the effective date of the first initial participating area established under said Unit Agreement and upon the expiration of which all legal subdivisions of unitized lands not entitled to be in a participating area are automatically eliminated from said Unit Agreement.

NOW, THEREFORE, in consideration of the premises and the mutual benefits to be derived the parties hereto agree severally among themselves as follows:

Section 2(e) appearing on Page 3 of said Unit Agreement is hereby amended by striking therefrom the figure and word "5 years" where it appears therein and substituting therefor the figure and word "8 years".

As hereby amended said Unit Agreement shall be and remain in full force and effect as to all its terms and provisions.

This agreement shall be binding upon and shall inure to the benefit of the heirs, personal representatives, successors and assigns of the parties hereto.

This because of Tallman case

AGO 570632

T & L RECORDS 12-18-64

LEASES

U-M

U-M LEASES IN KENAI GAS FIELD

THE FOLLOWING DOCUMENT(S) MAY NOT FILM LEGIBLY BECAUSE OF POOR QUALITY OF THE ORIGINAL.

Form No. 4-1138
Fourth Edition
(Sept. 1963)

ORIGINAL

ORIGINAL trans. FED. LSE 22330

Form approved.
Budget Bureau No. 42-R982.1

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

Office ANCHORAGE

Serial No. 028190

OFFER TO LEASE AND LEASE FOR OIL AND GAS
(Sec. 17 Noncompetitive 5-Year Public Domain Lease)

Receipt No. 144363

THIS OFFER WILL BE REJECTED AND RETURNED TO THE OFFEROR AND WILL AFFORD THE OFFEROR NO PRIORITY IF IT IS NOT PROPERLY FILLED IN AND EXECUTED OR IF IT IS NOT ACCOMPANIED BY THE REQUIRED DOCUMENTS OR PAYMENTS. SEE ITEM 9 OF GENERAL INSTRUCTIONS

(Fill in on a typewriter or print plainly in ink and sign in ink)

RECEIVED
BUREAU OF LAND MANAGEMENT
OCT 15 1954
PLEASE NOTIFY THE SIGNING OFFICER OF ANY CHANGE OF ADDRESS
LAND OFFICE
ANCHORAGE, ALASKA

1. Mr. ~~XXXX~~ M. B. Kirkpatrick
(Name)

525 3rd Avenue 10:00 AM
(Number and Street)

Anchorage, Alaska
(City and State)

hereby offers to lease all or any of the lands described in item 2 that are available for lease, pursuant and subject to the terms and provisions of the act of February 25, 1920 (41 Stat. 437, 30 U. S. C. sec. 181), as amended, hereinafter referred to as the act, and to all reasonable regulations of the Secretary of the Interior now or hereafter in force, when not inconsistent with any express and specific provisions herein, which are made a part hereof.

2. Land requested	3. Land included in lease (Not to be filled in by Offeror)
Territory of Alaska	
(State) (County)	(State) (County)
T. 4 N., R. 11 W., Seward Meridian	T. ____, R. ____, Meridian
Section 17: All	"Subject to Form 4-1383"
" 18: All	This lease embraces the area and the land described in Item 2.
" 19: All	
" 20: All	
2,494.72	The rental retained is the rental amount shown in Item 4.
2,495	
Total Area ____ Acres	Total Area ____ Acres. Rental retained prescribed by the regulation 43 CFR 192.82 applicable to leases in the States."

"Issued in accordance with Public Law 85-505 dated July 3, 1958, section 10 of which provided that the rentals of leases which issue on applications or offers filed prior to and which were pending on May 3, 1958 shall be at the rate of 25c per acre for the first year. However, the royalty rates shall be identical with those on leases in the States."

4. Amount remitted: Filing fee $10, Rental $ 623.75, Total $ 633.75

SUBJECT TO KENAI UNIT AGREEMENT NO. 14-08-001-6367 APPROVED JULY 30, 1959

5. Undersigned certifies as follows: (a) Offeror is a citizen of the United States. Native born X Naturalized ____ Corporation or other legal entity (specify what kind): ____

(b) Offeror's interests direct and indirect in oil and gas leases and applications or offers therefor including this offer in the same State do not exceed 15,360 chargeable acres. (c) Offeror accepts as a part of this lease, to the extent applicable, the stipulations provided for in 43 CFR 191.6. (d) Offeror is 21 years of age or over (or if a corporation or other legal entity, is duly qualified as shown by statements made or referred to herein). (e) Offeror has described all surveyed lands by legal subdivisions and unsurveyed lands by meter and bounds, and further states that there are no settlers on unsurveyed lands described herein.

6. Offeror's signature to this offer shall also constitute offeror's signature to, and acceptance of, this lease and any amendment thereto that may cover any land described in this offer open to lease application at the time the offer was filed but omitted from this lease for any reason, or signature to, or acceptance of, any separate lease for such land. The offeror further agrees that (a) this offer cannot be withdrawn, either in whole or in part, unless the withdrawal is received by the land office before this lease, an amendment to this lease, or a separate lease, whichever covers the land described in the withdrawal, has been signed in behalf of the United States, and (b) this offer and lease shall apply only to lands not within a known geologic structure of a producing oil or gas field at the time the offer is filed.

7. It is hereby certified that the statements made herein are true, complete and correct to the best of offeror's knowledge and belief, and are made in good faith.

IN WITNESS WHEREOF, Offeror has duly executed this instrument this 14th day of October 19 54

This form is submitted in lieu of official form 4-1138 and contains all of the provisions thereof as of the date of filing of this offer.

WITNESSES

525 3rd Avenue, Anchorage, Alaska (Witness' address)

525 3rd Avenue, Anchorage, Alaska (Witness' address)

M. B. Kirkpatrick (Lessee signature)

(Lessee signature)

AGO 570635

(Attorney-in-fact)

This lease for the lands described in item 3 above is hereby issued, subject to the provisions of the offer and on the reverse side hereof.

THE UNITED STATES OF AMERICA

By ____ (Signing officer)

Effective date of lease SEP 1 1958

MANAGER (Title) AUG 21 1958 (Date)

18 U. S. C. sec. 1001 makes it a crime for any person knowingly and willfully to make to any Department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

This form may be reproduced provided that the copies are exact reproductions on one sheet of both sides of this official form, in accordance with the provisions of 43 CFR 192.42 (a).

Section 1. *Rights of lessee.*—The lessee is granted the exclusive right and privilege to drill for, mine, extract, remove and dispose of all the oil and gas deposits, except helium gas, in the lands leased, together with the right to construct and maintain thereupon all works, buildings, plants, waterways, roads, telegraph or telephone lines, pipelines, reservoirs, tanks, pumping stations, or other structures necessary to the full enjoyment thereof, for a period of 5 years, and so long thereafter as oil or gas is produced in paying quantities subject to any unit agreement heretofore or hereafter approved by the Secretary of the Interior, the provisions of said agreement to govern the lands subject thereto where inconsistent with the terms of this lease. The lessee may also be entitled to an extension of the lease under section 3 of the act of August 8, 1946 (60 Stat. 951, 30 U. S. C. sec. 226).

Sec. 2. The lessee agrees:

(a) *Bonds.*—(1) To file any bond required by this lease and the current regulations and until such bond is filed not to enter on the land under this lease. (2) To maintain any bond furnished by the lessee as a condition for the issuance of this lease. (3) To furnish a bond in a sum double the amount of $1 per acre annual rental, but not less than $1,000 nor more than $5,000, upon the inclusion of any part of the leased land within the known geologic structure of a producing oil or gas field. (4) To furnish prior to beginning of drilling operations and maintain at all times thereafter as required by the lessor a bond in the penal sum of $5,000 with approved corporate surety, or with deposit of United States bonds as surety therefor, conditioned upon compliance with the terms of this lease, unless a bond in that amount is already being maintained or unless such a bond furnished by an operator of the lease is accepted. (5) Until a general lease bond is filed to furnish and maintain a bond in the penal sum of not less than $1,000 in those cases in which a bond is required by law for the protection of the owners of surface rights. (6) In all other cases where a bond is not otherwise required, to furnish, not less than 90 days before the due date of the next unpaid annual rental, a $1,000 bond conditioned on compliance with the lease obligations, but the requirement may be successively dispensed with by payment of each successive annual rental not less than 90 days prior to its due date. In lieu of any of the bonds described herein, the lessee may file such other bond as the regulations may permit.

(b) *Cooperative or unit plan.*—Within 30 days of demand, or, if the leased land is committed to an approved unit or cooperative plan and such plan is terminated prior to the expiration of this lease, within 30 days of demand made thereafter, to subscribe to and to operate under such reasonable cooperative or unit plan for the development and operation of the area, field, or pool, or part thereof, embracing the lands included herein as the Secretary of the Interior may then determine to be practicable and necessary or advisable, which plan shall adequately protect the rights of all parties in interest, including the United States.

(c) *Wells.*—(1) To drill and produce all wells necessary to protect the leased land from drainage by wells on lands not the property of the lessor, or lands of the United States leased at a lower royalty rate, or as to which the royalties and rentals are paid into different funds than are those of this lease; or in lieu of any part of such drilling and production, with the consent of the Director of the Geological Survey, to compensate the lessor in full each month for the estimated loss of royalty through drainage in the amount determined by said Director; (2) at the election of the lessee, to drill and produce other wells in conformity with any system of well spacing or production allotments affecting the field or area in which the leased lands are situated, which is authorized and sanctioned by applicable law or by the Secretary of the Interior; and (3) promptly after due notice in writing to drill and produce such other wells as the Secretary of the Interior may reasonably require in order that the leased premises may be properly and timely developed and produced in accordance with good operating practice.

(d) *Rentals and royalties.*—(1) To pay rentals and royalties in amount or value of production removed or sold from the leased lands as follows:

Rentals.—To pay the lessor in advance an annual rental at the following rates:

(a) If the lands are wholly outside the known geologic structure of a producing oil or gas field:

(i) For the first lease year, a rental of 50 cents per acre or fraction thereof, or if the lands are in Alaska, 25 cents per acre or fraction thereof;

(ii) For the second and third lease years, no rental.

(iii) For the fourth and fifth years, 25 cents per acre or fraction thereof.

(iv) For the sixth and each succeeding year, 50 cents per acre or fraction thereof, or if the lands are in Alaska, 25 cents per acre or fraction thereof.

(b) If the lands are wholly or partly within the known geologic structure of a producing oil or gas field:

(i) Beginning with the first lease year after 30 days' notice that all or part of the land is included in such a structure and for each year thereafter, prior to a discovery of oil or gas on the lands leased, $1 per acre or fraction thereof.

(ii) If this lease is committed to an approved cooperative or unit plan which includes a well capable of producing oil or gas and contains a general provision for allocation of production, the rental prescribed for the respective lease years in subparagraph (a) of this section, shall apply to the acreage not within a participating area, except that the rental for the second and the third lease years for such acreage shall be 25 cents per acre or fraction thereof.

Minimum royalty.—Commencing with the lease year beginning on or after a discovery on the leased land, to pay the lessor in lieu of rental, a minimum royalty of $1 per acre or fraction thereof at the expiration of each lease year, or the difference between the actual royalty paid during the year if less than $1 per acre, and the prescribed minimum royalty of $1 per acre, provided that if this lease is unitized, the minimum royalty shall be payable only on the participating acreage and rental shall be payable on the nonparticipating acreage as provided in subparagraph (b) (ii) above.

Royalty on production.—To pay the lessor 12½ percent royalty on the production removed or sold from the leased lands computed in accordance with the Oil and Gas Operating Regulations (30 CFR Pt. 221). *Provided*, however, that if this lease covers lands in Alaska and the lessee drills and makes the first discovery of oil or gas in commercial quantities in any geologic structure, the royalty on all production hereunder shall be 5 percent for 10 years following the date of such discovery, and thereafter the royalty rate shall be 12½ percent. If this lease is committed to an approved unit or cooperative plan (under which such a discovery is made), the 5-percent rate for 10 years following such discovery shall, for the purpose of computing royalty due the United States, inure to the benefit of all the land to which an allocation is made under such plan.

(2) It is expressly agreed that the Secretary of the Interior may establish reasonable minimum values for purposes of computing royalty on any or all oil, gas, natural gasoline, and other products obtained from gas, due consideration being given to the highest price paid for a part or for a substantial production of like quality in the same field, to the price received by the lessee, to posted prices, and to other relevant matters and, whenever appropriate, after notice and opportunity to be heard.

(3) When paid in value, royalties on production shall be due and payable monthly on the last day of the calendar month next following the calendar month in which produced. Where said royalty is based upon a royalty value established by the quantity and quality of the production removed from the leased lands, or where such royalty is based upon a posted price, such royalty products shall be delivered in merchantable condition on the premises where produced without cost to lessor, unless otherwise agreed to by the parties hereto, at such times and in such tanks provided by the lessee as reasonably may be required by the lessor, but in no case shall the lessee be required to hold such royalty oil or other products in storage beyond the last day of the calendar month next following the calendar month in which produced nor be responsible or held liable for the loss or destruction of royalty oil or other products in storage from causes over which he has no control.

(4) Rentals or minimum royalties may be waived, suspended or reduced and royalties on the entire leasehold or any portion thereof segregated for royalty purposes may be reduced if the Secretary of the Interior finds that, for the purpose of encouraging the greatest ultimate recovery of oil or gas and in the interest of conservation of natural resources, it is necessary, in his judgment, to do so in order to promote development, or because the lease cannot be successfully operated under the terms fixed herein.

(e) *Payments.*—Unless otherwise directed by the Secretary of the Interior, to make rental, royalty, or other payments to the lessor, to the order of the Treasurer of the United States, such payments to be tendered to the manager of the land office in the district in which the lands are located or to the Director of the Bureau of Land Management if there is no land office in the State in which the lands are located.

(f) *Contracts for disposal of products.*—To file with the Oil and Gas Supervisor of the Geological Survey not later than 30 days after the effective date thereof any contract, or evidence of other arrangement, for the sale or disposal of oil, gas, natural gasoline, and other products of the leased land; *Provided*, That nothing in any such contract or other arrangement shall be construed as modifying any of the provisions of the lease, including, but not limited to, provisions relating to gas waste, taking royalty in kind, and the method of computing royalties due as based on a minimum valuation and in accordance with the Oil and Gas Operating Regulations.

(g) *Statements, plats and reports.*—At such times and in such form as the lessor may prescribe, to furnish detailed statements showing the amounts and quality of all products removed and sold from the lease, the proceeds therefrom, and the amount used for production purposes or unavoidably lost; a plat showing development work and improvements on the leased lands; and a report with respect to stockholders, investments, depreciation and costs.

(h) *Well records.*—To keep a daily drilling record, a log, and complete information on all well surveys and tests in form acceptable to or prescribed by the lessor of all wells drilled on the leased lands, and an acceptable record of all subsurface investigations affecting said lands, and to furnish them, or copies thereof, to the lessor when required. All information obtained under this paragraph, upon the request of lessee, shall not be open to inspection by the public until the expiration of the lease.

(i) *Inspection.*—To keep open at all reasonable times for the inspection of any duly authorized officer of the Department, the leased premises and all wells, improvements, machinery, and fixtures thereon and all books, accounts, maps and records relative to operations and surveys or investigations on the leased lands or under the lease. All information obtained pursuant to any such inspection, upon the request of the lessee, shall not be open to inspection by the public until the expiration of the lease.

(j) *Diligence, prevention of waste, health and safety of workmen.*—To exercise reasonable diligence in drilling and producing the wells herein provided for unless consent to suspend operations temporarily is granted by the lessor; to carry on all operations in accordance with approved methods and practice as provided in the Oil and Gas Operating Regulations, having due regard for the prevention of waste of oil or gas or damage to deposits or formations containing oil, gas, or water or to coal measures or other mineral deposits, for conservation of gas energy, for the preservation and conservation of the property for future productive operations, and for the health and safety of workmen and employees; to plug properly and effectively all wells drilled in accordance with the provisions of this lease or of any prior lease or permit upon which the right to the lease was predicated before abandoning the same; to carry out at expense of the lessee all reasonable orders of the lessor relative to the matters in this paragraph, and that on failure of the lessee so to do the lessor shall have the right to enter on the property and to accomplish the purpose of such orders at the lessee's cost: *Provided*, That the lessee shall not be held responsible for delays or casualties occasioned by causes beyond lessee's control.

(k) *Taxes and wages, freedom of purchase.*—To pay when due, all taxes lawfully assessed and levied under the laws of the State or the United States upon improvements, oil and gas produced from the lands hereunder, or other rights, property, or assets of the lessee; to accord all workmen and employees complete freedom of purchase, and to pay all wages due workmen and employees at least twice each month in the lawful money of the United States.

(l) *Nondiscrimination.*—Not to discriminate against any employee or applicant for employment because of race, creed, color, or national origin, and to require an identical provision to be included in all subcontracts.

(m) *Assignment of oil and gas leases or interest therein.*—As required by applicable law, to file for approval within 90 days from the date of final execution any instrument of transfer made of this lease, or any interest therein, including assignments of record title, working or royalty interests, operating agreements and sublessees, such instrument to take effect upon the final approval by the Bureau of Land Management as of the first day of the lease month following the date of filing in the proper land office.

(n) *Pipelines to purchase or convey at reasonable rates and without discrimination.*—If owner, or operator, or owner of a controlling interest in any pipeline or of any company operating the same which may be operated accessible to the oil or gas derived from lands under this lease, to accept and convey said oil or gas without discrimination in favor of the production of the owner of such pipeline, operating a lease or purchasing or selling oil, gas, natural gasoline, or other products under the provisions of the act, or under the provisions of the act of August 7, 1947 (61 Stat. 913, 30 U. S. C. sec. 351).

(o) *Lands patented with oil and gas deposits reserved to the United States.*—To comply with all statutory requirements and regulations thereunder, if the lands embraced herein have been or shall hereafter be disposed of under the laws reserving to the United States the deposits of oil and gas therein, subject to such conditions as are or may hereafter be provided by the laws reserving such oil or gas.

(p) *Reserved or segregated lands.*—If any of the land included in this lease is embraced in a reservation or segregated for any particular purpose, to conduct operations thereunder in conformity with such requirements as may be made by the Director, Bureau of Land Management, for the protection and use of the land for the purpose for which it was reserved or segregated, so far as may be consistent with the use of the land for the purpose of this lease, which latter shall be regarded as the dominant use unless otherwise provided herein or separately stipulated.

(q) *Protection of surface, mineral resources and improvements.*—To take such reasonable steps as may be needed to prevent operations from unnecessarily: (1) Causing or contributing to soil erosion or damaging any forage and timber growth thereon, (2) polluting the waters of reservoirs, springs, streams or wells, (3) damaging crops, including forage, timber, or improvements of a surface owner, or (4) damaging range improvements whether owned by the United States or by its grazing permittees or lessees; and upon cessation of operations, so far as can reasonably be done, to restore the surface to its former condition. The lessor may prescribe the steps to be taken and restoration to be made with respect to lands of the United States and improvements thereon.

(r) *Overriding royalties.*—Not to create overriding royalties in excess of five percent except as otherwise authorized by the regulations.

(s) *Deliver premises in case of forfeiture.*—To deliver up to the lessor in good order and condition the land leased including all improvements which are necessary for the preservation of producing wells.

Sec. 3. The lessor reserves:

(a) *Easements and rights-of-way.*—The right to permit for joint or several use easements or rights-of-way, including easements in tunnels upon, through, or in the lands leased, occupied, or used as may be necessary or appropriate to the working of the same or of other lands containing the deposits described in the act, and the treatment and shipment of products thereof by or under authority of the Government, its lessees or permittees, and for other public purposes.

(b) *Disposition of surface.*—The right to lease, sell, or otherwise dispose of the surface of the leased lands under existing law or laws hereafter enacted, insofar as said surface is not necessary for the use of the lessee in the extraction and removal of the oil and gas therein, or to dispose of any resources in such lands which will not unreasonably interfere with operations under this lease.

(c) *Monopoly and fair prices.*—Full power and authority to promulgate and enforce all orders necessary to insure the sale of the production of the leased lands to the United States and to the public at reasonable prices, to protect the interests of the United States, to prevent monopoly, and to safeguard the public welfare.

(d) *Helium.*—Pursuant to section 1 of the act, and section 1 of the act of March 3, 1927 (44 Stat. 1387), as amended, the ownership and the right to extract helium from all gas produced under this lease, subject to such rules and regulations as shall be prescribed by the Secretary of the Interior. In case the lessee elects to take the helium the lessee shall deliver all gas containing same, or portion thereof desired, to the lessor at any point on the leased premises in the manner required by the lessor, for the extraction of the helium in such plant or reduction works for that purpose as the lessor may provide, whereupon the residue shall be returned to the lessee with no substantial delay in the delivery of gas produced from the well to the purchaser thereof. The lessee shall not suffer a diminution of value of the gas from which the helium has been extracted, or less otherwise, for which he is not reasonably compensated, save for the value of the helium extracted. The lessor further reserves the right to erect, maintain, and operate any and all reduction works and other equipment necessary for the extraction of helium on the premises leased.

(e) *Taking of royalties.*—All rights pursuant to section 36 of the act, to take royalties in amount or in value of production.

(f) *Casing.*—All rights pursuant to section 40 of the act to purchase casing and lease or operate valuable water wells.

(g) *Fissionable materials.*—Pursuant to the provisions of [illegible] 5 (b) (7) of the act of August 1, 1946 (60 Stat. 724, 760; 42 [illegible] 1801, 1805), all uranium, thorium, and other materials determined to be peculiarly essential to the production of fissionable materials, contained in whatever concentration, together with the right of the United States through its authorized agents or representatives at any time to enter upon the land and prospect for, mine and remove the same, making just compensation for any damage or injury occasioned thereby.

Sec. 4. *Drilling and producing restrictions.*—It is agreed that the rate of prospecting and developing and the quantity and rate of production from the lands covered by this lease shall be subject to control in the public interest by the Secretary of the Interior, and in the exercise of his judgment the Secretary may take into consideration, among other things, Federal laws, State laws, and regulations issued thereunder, or lawful agreements among operators regulating either drilling or production, or both. After unitization, the Secretary of the Interior, or any person, committee, or State or Federal officer or agency so authorized in the unit plan, may alter or modify from time to time, the rate of prospecting and development and the quantity and rate of production from the lands covered by this lease.

Sec. 5. *Surrender and termination of lease.*—The lessee may surrender this lease or any legal subdivision thereof by filing in the proper land office a written relinquishment, in triplicate, which shall be effective as of the date of filing subject to the continued obligation of the lessee and his surety to make payment of all accrued rentals and royalties and to place all wells on the land to be relinquished in condition for suspension or abandonment in accordance with the applicable lease terms and regulations.

Sec. 6. *Purchase of materials, etc., on termination of lease.*—Upon the expiration of this lease, or the earlier termination thereof pursuant to the last preceding section, the lessee shall have the privilege at any time within a period of 90 days thereafter of removing from the premises all machinery, equipment, tools, and materials other than improvements needed for producing wells. Any materials, tools, appliances, machinery, structures, and equipment subject to removal as above provided, which are allowed to remain on the leased lands shall become the property of the lessor on expiration of the 90-day period or such extension thereof as may be granted because of adverse climatic conditions throughout said period: *Provided*, That the lessee shall remove any or all of such property where so directed by the lessor.

Sec. 7. *Proceedings in case of default.*—If the lessee shall not comply with any of the provisions of the act or the regulations thereunder or of the lease or make default in the performance or observance of any of the terms hereof and such default shall continue for a period of 30 days after service of written notice thereof by the lessor, this lease may be canceled by the Secretary of the Interior in accordance with section 31 of the act; except that if this lease covers lands known to contain valuable deposits of oil or gas, the lease may be canceled only by judicial proceedings in the manner provided in section 31 of the act; but this provision shall not be construed to prevent the exercise by the lessor of any legal or equitable remedy which the lessor might otherwise have. Upon cancellation of this lease, any casing, material, or equipment determined by the lessor to be necessary for use in plugging or preserving any well drilled on the leased land shall become the property of the lessor. A waiver of any particular cause of forfeiture shall not prevent the cancellation and forfeiture of this lease for any other cause of forfeiture, or for the same cause occurring at any other time.

Sec. 8. *Heirs and successors-in-interest.*—It is further agreed that each obligation hereunder shall extend to and be binding upon, and every benefit hereof shall inure to, the heirs, executors, administrators, successors, or assigns of the respective parties hereto.

Sec. 9. *Unlawful interest.*—It is also further agreed that no Member of, or Delegate to, Congress, or Resident Commissioner, after his election or appointment, or either before or after he has qualified and during his continuance in office, and that no officer, agent, or employee of the Department of the Interior, except as provided in 43 CFR 7.4 (a) (1), shall be admitted to any share or part in this lease or derive any benefit that may arise therefrom; and the provisions of Sec. 3741 of the Revised Statutes of the United States, as amended (41 U. S. C. Sec. 22) and Secs. 431, 432 and 433, Title 18 U. S. Code, relating to contracts, enter into and form a part of this lease so far as the same may be applicable.

INSTRUCTIONS

A. GENERAL INSTRUCTIONS

1. This offer must be filled in on a typewriter or printed plainly in ink and must be signed in ink.

2. This form is to be used in offering to lease noncompetitively public domain lands or oil and gas deposits reserved to the United States in disposals of such lands for the purpose of drilling, mining, extracting, removing and disposing of oil and gas deposits, except helium. This form should not be used in offering to lease acquired lands or lands on a known geologic structure of a producing oil or gas field.

3. Offers to lease may be made by individuals 21 years of age or over who are citizens of the United States, and by corporations, partnerships or associations.

4. This offer must be prepared in quintuplicate and filed in the proper land office. The term "filing" means the actual receipt of the offer in the proper land office. If the land is in a State in which there is no land office, the offer must be filed with the Bureau of Land Management, Department of the Interior, Washington 25, D. C. If less than five copies are filed, the offeror will have 30 days from the date of first filing to file the other required copies, failing in which the offer will be rejected and returned to the offeror and will afford no priority.

5. The offeror shall mark one of the copies first filed at the top with the word "original." If that is not done, the manager will so mark one copy. If there is any variation in the land descriptions among the five copies, the one marked "original" shall govern as to the lands covered by the lease.

6. If additional space is needed in furnishing any of the required information it should be prepared on additional sheets, initialed and attached and made part of this offer to lease, such additional sheets to be attached to each copy of the form submitted.

7. If any of the land described in item 2 of the offer is open to oil and gas leasing when the offer is filed but is omitted from the lease for any reason and thereafter becomes available for leasing to the offeror, the original lease will be amended to include the omitted land, unless, before the issuance of the amendment on Form 4-1611a, the land office receives the withdrawal of the offer as to such land or an objection to including it in the lease to be issued in accordance with 43 CFR 192.40, in which event a separate lease will be issued. If the lease is amended the rental charged and the lease term will be the same as though the added land had been included in the original lease when it was issued.

8. As an incident to the assignment of the whole interest in all or any part of the lease, the lessee may assign the whole interest in all or any part of the offer. As an incident to the assignment of an undivided fractional interest in the whole lease, the lessee may assign an undivided fractional interest in the whole offer. Applications for approval of assignments of an offer must include a statement that the assignee agrees to be bound by the offer to the extent it is assigned and must be signed by the assignee. In other instances assignments of the offer will not be approved prior to the issuance of a lease for the lands or deposits covered by said assignments.

9. The offer will be rejected and returned to the offeror and will affect the date of the priority if: (a) The land description is insufficient to identify the lands or the lands are not entirely within a 6-mile square. (b) The total acreage exceeds 2,560 acres, except where the rule of approximation applies or is less than 640 acres or the equivalent of a section and is not within the exceptions in 43 CFR 192.42 (d). (c) The full filing fee and the first year's rental do not accompany the offer, the rental payment to be for the total acreage if known, and if not known, for the total acreage computed on the basis of 40 acres for each smallest legal subdivision. (d) The offer is signed by an agent in behalf of the offeror and the offer is not accompanied by a statement over the offeror's own signature with respect to holdings and citizenship and by the statements and evidence required by 43 CFR 192.42 (e) (4). (e) The offer is signed by a guardian or trustee in behalf of a minor and is not accompanied by the evidence required by 43 CFR 192.42 (e) (5). (f) Less than five copies of the offer are filed and the copies lacking are not received in the land office before the expiration of 30 days from the date of receipt of the copies first filed. (g) There is noncompliance with item 5 (c), 5 (d), and 5 (e) of the Special Instructions or (h) the offer is not filed on a current form. The offeror will be given an opportunity to file a new offer within 30 days from service of the rejection, and the fee and rental payments on the old offer will be applied to the new offer if the new offer shows the serial and receipt numbers of the old offer. The advance rental will be returned unless within the 30-day period another offer is filed.

B. SPECIAL INSTRUCTIONS

Item 2.—Total area of land requested should be shown in acres in space provided at bottom of item 2. That area, except where the rule of approximation applies, must not exceed 2,560 acres or be less than 640 acres or the equivalent of a section except as provided in 43 CFR 192.42 (d). All of the land must be within a 6-mile square. The lands requested if surveyed should be described by legal subdivisions, showing meridian, township, range, and section, and if unsurveyed, by metes and bounds connected by courses and distances with some corner of the public land survey. Where possible the approximate length of each side of unsurveyed lands should be stated.

Item 3.—This space is reserved for the lessor. When leases are issued they will contain the description of the lands by tracts and total acreage.

Item 4.—The total amount remitted should be the sum of $10 filing fee and the first year's rental of the land requested at the rate of 50 cents an acre or fraction of an acre. The $10 filing fee is retained as a service charge, even in those cases where the offer to lease is completely rejected. In order to protect the offeror's priorities with respect to the land requested, it is important that the rental payment submitted with the offer be sufficient to cover all the land requested at the rate of 50 cents an acre or fraction thereof. If the land requested includes lots or irregular quarter-quarter sections, the exact area of which is not known to the offeror, rental may be submitted for the purpose of the offer on the basis of each such lot or quarter-quarter section containing 40 acres. If the offer is withdrawn in whole or in part before a lease is issued or if the offer is rejected in whole or in part, the rental remitted for the parts withdrawn or rejected will be returned. Where at the time the lease is to be issued, the land applied for or any part of it is within a known geologic structure of a producing oil or gas field, the lessee will be billed for the additional rental of 50 cents an acre in all the leased land as the yearly rental on such lands is $1 per acre. In Alaska, the rental payment to accompany the offer should be at the rate of 25 cents per acre.

Item 6 (a).—Lessee will indicate whether a citizen by birth or naturalization. If production is obtained under this lease or allocated to it, the citizenship status of the lessee will be verified.

If lessee is an unincorporated association (including a partnership) the offer must be accompanied by a certified copy of the articles of association together with the same showing as to citizenship and holdings of its members as required of an individual.

If lessee is a corporation it must show it is qualified with respect to the citizenship provision by filing a copy of its articles of incorporation, and it must furnish a statement showing the percentage of each class of its stock, and the percentage of all of its stock which is owned or controlled by or on behalf of persons whom the corporation knows to be or who the corporation has reason to believe are aliens, or who have addresses outside of the United States, indicating which classes of stock have voting rights. If more than 10 percent of the voting stock or of all of the stock is owned or controlled by or on behalf of such persons, the corporation must give their names and addresses, the amount and class of stock held by each, and, to the extent known to the corporation, or which can be reasonably ascertained by it, the facts as to the citizenship of each such person. If any appreciable percentage of the stock of the corporation is held by aliens of the excepted class, its application will be denied. If 20 percent or more of the stock of any class is owned or controlled by or on behalf of any one stockholder, a separate showing of his citizenship and holdings must be furnished.

If a certificate of incorporation or association has been filed, a reference to the previous record by serial number, together with a statement of any subsequent amendments, will be sufficient.

Item 6 (d).—Acreage included in unit plans and certain section 16 and 36 leases is not chargeable.

Item 7 (a).—Whenever applicable, the stipulations referred to will be made a part of this lease and will be furnished the lessee with the lease when issued. The forms covering them with a brief description are as follows: 4-216 stipulations for lands where the surface control is under the jurisdiction of the Department of Agriculture; 4-467 lands potentially irrigable; 4-467a lands within the flow limits of a reservoir site; 4-467b lands within the drainage area of a constructed reservoir. Whenever other stipulations are necessary, lessee will be required to agree to them before the issuance of the lease.

Item 8 (d).—If lessee is a corporation, an officer to leave will be accepted if accompanied either by the minutes of the meeting of the board of directors, or a copy of the bylaws indicating the officer signing the offer to lease has authority to do so, or by a certificate of the secretary or the assistant secretary of the corporation to that effect over the corporate seal.

Item 9 (c).—If there are settlers attach a sheet giving the name and postoffice address of each and description of the lands claimed by [illegible] and bounds and approximate legal subdivision.

numbered according to numbers on offer form.

Printed by WOLCOTT'S
214 S. Spring St., Los Angeles 12, Calif.

AGO 570636

THE PRECEDING DOCUMENT(S MAY NOT FILM
LEGIBLY BECAUSE OF POOR QUALITY OF THE
ORIGINAL

TERMS AND CONDITIONS

(1) As used herein:

(a) the term "lessee" includes the lessee, heirs and assigns of the lessee and persons operating on behalf of the lessee;

(b) the term "wildlife resources" include fish and wildlife resources and concentrations, fish and wildlife management operations and range improvements and facilities;

(c) the term "authorized officer" means the State Supervisor of the Bureau of Land Management in the State in which the land is located, and, in Alaska, the Refuge Manager of the Bureau of Sport Fisheries and Wildlife;

(2) The lessee shall:

(a) comply with all the rules and regulations of the Secretary of the Interior;

(b) prior to the beginning of operations, appoint and maintain at all times during the term of the lease a local agent upon whom may be served written orders or notices respecting matters contained in these stipulations and to inform the authorized officer in writing of the name and address of such agent. If a substitute agent is appointed, the lessee shall immediately inform the said representative;

(c) conduct all authorized activities in a manner satisfactory to the authorized officer with due regard for good land management and avoid damage to improvements, timber, crops, and wildlife cover, and fill all sump holes, ditches, and other excavations or cover all debris, and so far as reasonably possible, restore the surface of the leased lands to their former condition and when required to bury all pipelines below plow depth. The authorized officer shall have the right to enter all the premises at any time to inspect both the installation and operational activities of the lessee;

(d) take such steps as may be necessary to prevent damage to wildlife;

(e) do all in his power to prevent and suppress forest, brush, or grass fires and to require his employees, contractors, subcontractors and employees of contractors or subcontractors to do likewise;

(f) install adequate blow-out prevention equipment;

(g) construct ring dikes and sump pits to confine drilling mud and other pollutants and make safe disposition of salt water by use of injection wells or such other method as may be approved in the plan of operation;

(h) cover flare pits in acres of wildlife concentration;

IN REPLY REFER TO:

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

Form 4-1383

STIPULATIONS

For Inclusion in Oil and Gas Leases Entered Into Pursuant to 43 CFR 192.9 Relating to Oil and Gas Leases in Wildlife Refuge, Game Range, and Coordination Lands

INSTRUCTIONS

(1) The following stipulations will be made a part of Interior Department Lease Form No. 4-1158 (6th Edition of April 1957) and Lease Form No. 4-1196 (Edition of December 1954), and all revisions thereof and substitutions therefor. These stipulations will be made applicable as terms and conditions of performance by lessees under all oil and gas leases entered into under authority vested in the Secretary of the Interior over game range, coordination or Alaska Wildlife lands pursuant to the order of the Secretary of the Interior published in 23 Federal Register 227, January 11, 1958, 43 CFR 192.9.

(2) Should compliance with one or more of these terms and conditions be considered unduly burdensome and unnecessary to the protection of wildlife resources, the lessee may request waiver thereof by letter addressed to the Secretary of the Interior setting forth, in full, the reasons why a waiver is considered necessary. The authority to grant such waivers shall be discretionary and may be exercised only by the Secretary or the Under Secretary of the Interior.

(3) The authorized officer shall (a) approve no plan of operation that contains provisions inconsistent with the stipulations hereinafter set forth; (b) waive no term or condition in a lease; or (c) exercise no discretion vested in him unless he is satisfied the exercise of that discretion will not damage any wildlife resource.

(4) Drilling and production operations under the lease shall be under the direction of the Geological Survey.

(o) agree to respect and comply with any new requirements imposed by the Secretary of the Interior, or the authorized officer, on the operating program as operating experience proves necessary in order to give complete protection to wildlife populations and wildlife habitat on the areas leased.

(3) The lessee shall not:

(a) construct roads, pipelines, utility lines, and attendant facilities that are either unnecessary or which might interfere with wildlife habitat or resources or with drainage;

(b) modify or change the character of streams, lakes, ponds, water holes, seeps, and marshes, except by advance approval in writing by the authorized officer nor shall he in any way pollute such streams, lakes, ponds, water holes, seeps, or marshes;

(c) conduct operations at such times as will interfere with wildlife concentrations;

(d) conduct geological or geophysical explorations that might damage any wildlife resource and such operations shall be conducted only in accordance with advance approval in writing by the authorized officer as to the time, manner of travel, and disturbances of surfaces and the facilities required for the protection of wildlife;

(e) use explosives in fish spawning or rearing areas, nesting areas, lambing grounds, or other areas of wildlife concentrations during periods of intense activity or at any other time or in any manner that might damage any wildlife resources; the pattern, size, and depth of seismographic shots shall be submitted to the authorized officer for advance approval in writing and immediately following the detonation of any seismographic charge, the hole shall be filled or plugged and any surface damage repaired to the satisfaction of the authorized officer;

(f) without advance approval in writing, use any water or water source controlled or developed by the United States;

(g) use mobile equipment under such conditions as to permanently damage surface resources, cause scarring and erosion, or interfere with wildlife concentrations;

(h) conduct geological, or geophysical, or core drilling operations or construct roads, bunkhouses or any facilities or drill or produce under a lease until the submittal and approval in writing of a plan of operation pursuant to Section (2)(m) supra or deviate therefrom until any revisions or amendments of said plan have been approved in writing by the authorized officer.

(i) burn rubbish, trash, or other inflammable materials or use explosives in a manner or at a time that would constitute a fire hazard.

April 17, 1958

(Sgd) Fred A. Seaton
Secretary of the Interior

(i) remove derricks, dikes, equipment, and structures not required in producing operations within 60 days after the completion of drilling;

(j) comply with and see to it that his agents and employees comply with all Federal, State, or territorial laws relating to hunting, fishing, and trapping;

(k) commit the lease to any unit plan required in the interest of conservation of oil or gas resources or for the protection of wildlife;

(l) prior to the conduct of geological, geophysical, or core drilling operations or construction of any facilities, or prior to operations to drill or produce, submit in triplicate for approval in writing by the authorized officer a plan of operation that will include detailed statements indicating the manner in which the lessee will comply with these stipulations together with a statement that the lessee agrees that compliance with these stipulations and with the approved plan of operations are conditions of performance under this lease and that failure to comply with these provisions (unless they are waived by the Secretary or the Under Secretary of the Interior) will be grounds for cancellation of the lease by the United States. Notwithstanding other provisions in these stipulations, the lessee shall include in any plan of operation specific provisions relating to: The time, place, depth and strength of seismographic shots, maps showing the location of his leases included in the plan, actual and proposed access roads, bunkhouses, proposed well locations, storage and utility facilities, water storage, pipelines and pumping stations; the type of safety equipment that will be employed; the methods to be used to assure the disposition of drilling mud, pollutants, and other debris; the location of facilities in relation to flood levels; and such other specific matters as the authorized officer may require. The plan of operation shall be kept current in all respects and all revisions and amendments submitted to the authorized officer for written approval;

(m) do all things reasonably necessary to prevent or reduce to the fullest extent scarring and erosion of the land, pollution of the water resources and any damage to the watershed. Where construction, operation, or maintenance of any of the facilities on or connected with this lease causes damage to the watershed or pollution of the water resource, the lessee agrees to repair such damage, including reseeding and to take such corrective measures to prevent further pollution or damage to the watershed as are deemed necessary by the authorized officer;

(n) file the bond required by Sec. 2a(4) of the lease before conducting any operations on the leasehold, and file any additional bond required by the authorized officer to pay for damages to wildlife habitat, including trees and shrubs, or wildlife improvements;

Form No. 4-1158
Fifth Edition
(Sept. 1954)

Budget Bureau No. 42-R900.1

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

Office ANCHORAGE

Serial No. 028053-A

ORIGINAL

OFFER TO LEASE AND LEASE FOR OIL AND GAS
(Sec. 17 Noncompetitive 5-Year Public Domain Lease)

Receipt No. 044316

THIS OFFER MAY BE REJECTED AND RETURNED TO THE OFFEROR AND WILL AFFORD THE OFFEROR NO PRIORITY IF IT IS NOT PROPERLY FILLED IN AND EXECUTED OR IF IT IS NOT ACCOMPANIED BY THE REQUIRED DOCUMENTS OR PAYMENTS. SEE ITEM 9 OF GENERAL INSTRUCTIONS

(Fill in on a typewriter or print plainly in ink and sign in ink)

RECEIVED
BUREAU OF LAND MANAGEMENT
OCT 3 1955
LAND OFFICE
ANCHORAGE

Trans. Fed. Lse. ADL 09460

1. Miss THE OHIO OIL COMPANY
(Name)

437 SOUTH HILL STREET
(Number and Street)

LOS ANGELES 13, CALIFORNIA
(City and State)

PLEASE NOTIFY THE SIGNING OFFICER OF ANY CHANGE OF ADDRESS.

Hereby offers to lease all or any of the lands described in item 2 that are available for lease, pursuant and subject to the terms and provisions of the act of February 25, 1920 (41 Stat. 437, 30 U. S. C. sec. 181), as amended, hereinafter referred to as the act, and to all reasonable regulations of the Secretary of the Interior now or hereafter in force, when not inconsistent with any express and specific provisions herein, which are made a part hereof.

2. Land requested	3. Land included in lease (Not to be filled in by Offeror)
Territory of Alaska (State) (County)	(State) (County)
T. 4 N., R. 11 W., Seward Meridian	T. ..., R. ..., Meridian
Section 16: All	This lease embraces the area and the land described in Item 2. The rental retained is the rental amount shown in Item 4. SUBJECT TO KENAI UNIT AGREEMENT NO. 14-08-001-4367 APPROVED JULY 30, 1958
Total Area 640 Acres	Total Area ... Acres Rental retained $...

4. Amount remitted: ~~Filing fee $10~~, Rental $ 160.00, Total $ 160.00

5. Undersigned certifies as follows:
(a) Offeror is a citizen of the United States. Native born ... Naturalized ... Corporation or other legal entity (specify what kind): an Ohio corporation

(b) Offeror's interests direct and indirect in oil and gas leases and applications or offers therefor including this offer do not exceed 46,080 chargeable acres in the same State, or 100,000 chargeable acres in Alaska. (c) Offeror accepts as a part of this lease, to the extent applicable, the stipulations provided for in 43 CFR 191.6. (d) Offeror is 21 years of age or over (or if a corporation or other legal entity, is duly qualified as shown by statements made or referred to herein). (e) Offeror has described all surveyed lands by legal subdivisions and unsurveyed lands by metes and bounds, and further states that there are no settlers on unsurveyed lands described herein.

6. Offeror's signature to this offer shall also constitute offeror's signature to, and acceptance of, this lease and any amendment thereto that may cover any land described in this offer open to lease application at the time the offer was filed but omitted from this lease for any reason, or signature to, or acceptance of, any separate lease for such land. The offeror further agrees that (a) this offer cannot be withdrawn, either in whole or in part, unless the withdrawal is received by the land office before this lease, an amendment to this lease, or a separate lease, whichever covers the land described in the withdrawal, has been signed in behalf of the United States, and (b) this offer and lease shall apply only to lands not within a known geologic structure of a producing oil or gas field at the time the offer is filed.

7. If this lease form does not contain all of the terms and conditions of the lease form in effect at the date of filing, the offeror further agrees to be bound by the terms and conditions contained in that form.

8. It is hereby certified that the statements made herein are complete and correct to the best of offeror's knowledge and belief and are made in good faith.

IN WITNESS WHEREOF, Offeror has duly executed this instrument this 30th day of September 1955

Witness: Marie L. Lawson, 1828 Cheryl Ave., La Crescenta, Calif.
(Name and address)

Witness: Gladys M. O'Brien, 3442 Altura Ave., La Crescenta, Calif.
(Name and address)

AGO 570641

THE OHIO OIL COMPANY
(Lessee signature)

By George Lawson
(Lessee signature) Division Manager

(Attorney-in-fact)

This lease for the lands described in item 3 above is hereby issued, subject to the provisions of the offer and on the reverse side hereof.

THE UNITED STATES OF AMERICA

By Virgil O. Larson
(Signing officer)

Effective date of lease OCT 1 1955

MANAGER
(Title)

OCT 25 1955
(Date)

18 U. S. C. sec. 1001 makes it a crime for any person knowingly and willfully to make to any Department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

This form may be reproduced provided that the copies are exact reproductions on one sheet of both sides of this official form, in accordance with the provisions of 43 CFR 192.42 (a).

16—630.1-7

LEASE TERMS

Section 1. Rights of lessee.—The lessee is granted the exclusive right and privilege to drill for, mine, extract, remove, and dispose of all the oil and gas deposits, except helium gas, in the lands leased, together with the right to construct and maintain thereupon all works, buildings, plants, waterways, roads, telegraph or telephone lines, pipelines, reservoirs, tanks, pumping stations, or other structures necessary to the full enjoyment thereof, for a period of 5 years, and so long thereafter as oil or gas is produced in paying quantities; subject to any unit agreement heretofore or hereafter approved by the Secretary of the Interior, the provisions of said agreement to govern the lands subject thereto where inconsistent with the terms of this lease. At the expiration of the initial 5-year term, an application may be made for extension of the lease in accordance with the regulation 43 CFR 192.150.

Sec. 2. The lessee agrees:

(a) *Bonds.*—(1) To file any bond required by this lease and the current regulations and until such bond is filed not to enter on the land under this lease. (2) To maintain any bond furnished by the lessee as a condition for the issuance of this lease. (3) To furnish a bond in a sum double the amount of $1 per acre annual rental, but not less than $1,000 nor more than $5,000, upon the inclusion of any part of the leased land within the known geologic structure of a producing oil or gas field. (4) To furnish prior to beginning of drilling operations and maintain at all times thereafter as required by the lessor a bond in the penal sum of $5,000 with approved corporate surety, or with deposit of United States bonds as surety therefor, conditioned upon compliance with the terms of this lease, unless a bond in that amount is already being maintained or unless such a bond furnished by an operator of the lease is accepted. (5) Until a general lease bond is filed to furnish and maintain a bond in the penal sum of not less than $1,000 in those cases in which a bond is required by law for the protection of the owners of surface rights. In lieu of any of the bonds described herein, the lessee may file such other bond as the regulations may permit.

(b) *Cooperative or unit plan.*—Within 30 days of demand, or, if the leased land is committed to an approved unit or cooperative plan and such plan is terminated prior to the expiration of this lease, within 30 days of demand made thereafter, to subscribe to and to operate under such reasonable cooperative or unit plan for the development and operation of the area, field, or pool, or part thereof, embracing the lands included herein as the Secretary of the Interior may then determine to be practicable and necessary or advisable, which plan shall adequately protect the rights of all parties in interest, including the United States.

(c) *Wells.*—(1) To drill and produce all wells necessary to protect the leased land from drainage by wells on lands not the property of the lessor, or lands of the United States leased at a lower royalty rate, or as to which the royalties and rentals are paid into different funds than are those of this lease; or in lieu of any part of such drilling and production, with the consent of the Director of the Geological Survey, to compensate the lessor in full each month for the estimated loss of royalty through drainage in the amount determined by said Director; (2) at the election of the lessee, to drill and produce other wells in conformity with any system of well spacing or production allotments affecting the field or area in which the leased lands are situated, which is authorized and sanctioned by applicable law or by the Secretary of the Interior; and (3) promptly after due notice in writing to drill and produce such other wells as the Secretary of the Interior may reasonably require in order that the leased premises may be properly and timely developed and produced in accordance with good operating practice.

(d) *Rentals and royalties.*—(1) To pay rentals and royalties in amount or value of production removed or sold from the leased lands as follows:

Rentals.—To pay the lessor in advance an annual rental at the following rates:

(a) If the lands are wholly outside the known geologic structure of a producing oil or gas field:
- (i) For the first lease year, a rental of 50 cents per acre or fraction thereof, or if the lands are in Alaska, 25 cents per acre or fraction thereof;
- (ii) For the second and third lease years, no rental.
- (iii) For the fourth and fifth years, 25 cents per acre or fraction thereof.
- (iv) For the sixth and each succeeding year, 50 cents per acre or fraction thereof, or if the lands are in Alaska, 25 cents per acre or fraction thereof.

(b) If the lands are wholly or partly within the known geologic structure of a producing oil or gas field:
- (i) Beginning with the first lease year after 30 days' notice that all or part of the land is included in such a structure and for each year thereafter, prior to a discovery of oil or gas on the lands leased, $1 per acre or fraction thereof.
- (ii) If this lease is committed to an approved cooperative or unit plan which includes a well capable of producing oil or gas and contains a general provision for allocation of production, the rental prescribed for the respective lease years in subparagraph (a) of this section, shall apply to the acreage not within a participating area, except that the rental for the second and the third lease years for such acreage shall be 25 cents per acre or fraction thereof.

Minimum royalty.—Commencing with the lease year beginning on or after a discovery on the leased land, to pay the lessor in lieu of rental, a minimum royalty of $1 per acre or fraction thereof at the expiration of each lease year, or the difference between the actual royalty paid during the year if less than $1 per acre, and the prescribed minimum royalty of $1 per acre, provided that if this lease is unitized, the minimum royalty shall be payable only on the participating acreage and rental shall be payable on the nonparticipating acreage as provided in subparagraph (b) (ii) above.

Royalty on production.—To pay the lessor 12½ percent royalty on the production removed or sold from the leased lands computed in accordance with the Oil and Gas Operating Regulations (30 CFR Pt. 221). Provided, however, that if this lease covers lands in Alaska and the lessee drills and makes the first discovery of oil or gas in commercial quantities in any geologic structure, the royalty on all production hereunder shall be 5 percent for 10 years following the date of such discovery, and thereafter the royalty rate shall be 12½ percent. If this lease is committed to an approved unit or cooperative plan (under which such a discovery is made), the 5-percent rate for 10 years following such discovery shall, for the purpose of computing royalty due the United States inure to the benefit of all the land to which an allocation is made under such plan.

(2) It is expressly agreed that the Secretary of the Interior may establish reasonable minimum values for purposes of computing royalty on any or all oil, gas, natural gasoline, and other products obtained from gas, due consideration being given to the highest price paid for a part or for a majority of production of like quality in the same field, to the price received by the lessee, to posted prices, and to other relevant matters and, whenever appropriate, after notice and opportunity to be heard.

(3) When paid in value, such royalties on production shall be due and payable monthly on the last day of the calendar month next following the calendar month in which produced. When paid in amount of production, such royalty products shall be delivered in merchantable condition on the premises where produced without cost to lessor, unless otherwise agreed to by the parties hereto, at such times and in such tanks provided by the lessee as reasonably may be required by the lessor, but in no case shall the lessee be required to hold such royalty oil or other products in storage beyond the last day of the calendar month next following the calendar month in which produced nor be responsible or held liable for the loss or destruction of royalty oil or other products in storage from causes over which he has no control.

(4) Rentals or minimum royalties may be waived, suspended or reduced and royalties on the entire leasehold or any portion thereof segregated for royalty purposes may be reduced if the Secretary of the Interior finds that, for the purpose of encouraging the greatest ultimate recovery of oil or gas and in the interest of conservation of natural resources, it is necessary, in his judgment, to do so in order to promote development, or because the lease cannot be successfully operated under the terms fixed herein.

(e) *Payments.*—Unless otherwise directed by the Secretary of the Interior, to make rental, royalty, or other payments to the lessor, to the order of the Bureau of Land Management at the place mentioned in the regulation 43 CFR 191.13. If there is no well on the leased lands capable of producing oil or gas in paying quantities, the failure to pay rental on or before the anniversary date shall automatically terminate the lease by operation of law. However, if the time for payment falls on a day in which the proper office to receive payment is closed, payment shall be deemed timely if made on the next official working day.

(f) *Contracts for disposal of products.*—To file with the Oil and Gas Supervisor of the Geological Survey not later than 30 days after the effective date thereof any contract, or evidence of other arrangement, for the sale or disposal of oil, gas, natural gasoline, and other products of the leased land: *Provided*, That nothing in any such contract or other arrangement shall be construed as modifying any of the provisions of this lease, including, but not limited to, provisions relating to gas waste, taking royalty in kind, and the method of computing royalties due the lessor on a minimum valuation and in accordance with the Oil and Gas Operating Regulations.

(g) *Statements, plats and reports.*—At such times and in such form as the lessor may prescribe, to furnish detailed statements showing the amounts and quality of all products removed and sold from the lease, the proceeds therefrom, and the amount used for production purposes or unavoidably lost; a plat showing development work and improvements on the leased lands; and a report with respect to stockholders, investments, depreciation, and costs.

(h) *Well records.*—To keep a daily drilling record, a log and complete information on all well surveys and tests in form acceptable to or prescribed by the lessor of all wells drilled on the leased lands, and an acceptable record of all subsurface investigations affecting said lands, and to furnish them, or copies thereof, to the lessor when required. All information obtained under this paragraph, upon the request of lessee, shall not be open to inspection by the public until the expiration of the lease.

(i) *Inspection.*—To keep open at all reasonable times for the inspection of any duly authorized officer of the Department, the leased premises and all wells, improvements, machinery, and fixtures thereon and all books, accounts, maps and records relative to operations and surveys or investigations on the leased lands or under the lease. All information obtained pursuant to any such inspection, upon the request of the lessee, shall not be open to inspection by the public until the expiration of the lease.

(j) *Diligence, prevention of waste, health and safety of workmen.*—To exercise reasonable diligence in drilling and protecting the wells herein provided for unless consent to suspend operations temporarily is granted by the lessor; to carry on all operations in accordance with approved methods and practice as provided in the Oil and Gas Operating Regulations, having due regard for the prevention of waste of oil or gas or damage to deposits or formations containing oil, gas, or water or to coal measures or other mineral deposits, for conservation of gas energy, for the preservation and conservation of the property for future productive operations, and for the health and safety of workmen and employees; to plug properly and effectively all wells drilled in accordance with the provisions of the lease or of any prior lease or permit upon which the right to this lease was predicated before abandoning the same; to carry out at expense of the lessee all reasonable orders of the lessor relative to the matters in this paragraph, and that on failure of the lessee so to do the lessor shall have the right to enter on the property and to accomplish the purpose of such orders at the lessee's cost: *Provided*, That the lessee shall not be held responsible for delays or casualties occasioned by causes beyond lessee's control.

(k) *Taxes and wages, freedom of purchase.*—To pay when due, all taxes lawfully assessed and levied under the laws of the State or the United States upon improvements, oil and gas produced from the lands hereunder, or other rights, property, or assets of the lessee; to accord all workmen and employees complete freedom of purchase; and to pay all wages due workmen and employees at least twice each month in the lawful money of the United States.

(l) *Nondiscrimination.*—In connection with the performance of work under this contract, the contractor agrees not to discriminate against any employee or applicant for employment because of race, religion, color, or national origin. The aforesaid provision shall include, but not be limited to, the following: employment, upgrading, demotion, or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The contractor agrees to post hereafter in conspicuous places, available to employees and applicants for employment, notices to be provided by the contracting officer setting forth the provisions of the nondiscrimination clause.

The contractor further agrees to insert the foregoing provision in all subcontracts hereunder, except subcontracts for standard commercial supplies or raw materials.

(m) *Assignment of oil and gas lease or interest therein.*—As required by applicable law, to file for approval within 90 days from the date of final execution any instrument of transfer made of this lease, or any interest therein, including assignments of record title, working or royalty interests, operating agreements and subleases, such instrument to take effect upon the final approval by the Bureau of Land Management as of the first day of the lease month following the date of filing in the proper land office.

(n) *Pipelines to purchase or convey at reasonable rates and without discrimination.*—If owner, or operator, or owner of a controlling interest in any pipeline or of any company operating the same which may be operated accessible to the oil or gas derived from lands under this lease, to accept and convey and, if a purchaser of such products, to purchase at reasonable rates and without discrimination the oil or gas of the Government or of any citizen or company not the owner of any pipeline, operating a lease or purchasing or selling oil gas, natural gasoline, or other products under the provisions of the act, or under the provisions of the act of August 7, 1947 (61 Stat. 913, 30 U. S. C. sec. 351).

(o) *Lands patented with oil and gas deposits reserved to the United States.*—To comply with all statutory requirements and regulations thereunder, if the lands embraced herein have been or shall hereafter be disposed of under the laws reserving to the United States the deposits of oil and gas the same, subject to such conditions as are or may hereafter be provided by the laws reserving such oil or gas.

(p) *Reserved or segregated lands.*—If any of the land included in this lease is embraced in a reservation or segregated for any particular purpose, to conduct operations thereunder in conformity with such requirements as may be made by the Director, Bureau of Land Management, for the protection and use of the land for the purpose for which it was reserved or segregated, so far as may be consistent with the use of the land for the purpose of this lease, which latter shall be regarded as the dominant use unless otherwise provided herein or separately stipulated.

(q) *Protection of surface, natural resources and improvements.*—To take such reasonable steps as may be needed to prevent operations from unnecessarily: (1) Causing or contributing to soil erosion or damaging any forage and timber growth thereon, (2) polluting the waters of reservoirs, springs, streams of wells, (3) damaging crops, including forage, timber, or improvements of a surface owner, or (4) damaging range improvements whether owned by the United States or by its grazing permittees or lessees; and upon conclusion of operations, so far as can reasonably be done, to restore the surface to its former condition. The lessor may prescribe the steps to be taken and restoration to be made with respect to lands of the United States and improvements thereon.

(r) *Overriding royalties.*—Not to create overriding royalties in excess of five percent except as otherwise authorized by the regulations.

(s) *Deliver premises in case of forfeiture.*—To deliver up to the lessor in good order and condition the land leased including all improvements which are necessary for the preservation of producing wells.

Sec. 3. The lessor reserves:

(a) *Easements and rights-of-way.*—The right to permit for joint or several use easements or rights-of-way, including easements in tunnels upon, through, or in the lands leased, occupied, or used as may be necessary or appropriate to the working of the same or of other lands containing the deposits described in the act, and the treatment and shipment of products thereof by or under authority of the Government, its lessees or permittees, and for other public purposes.

(b) *Disposition of surface.*—The right to lease, sell, or otherwise dispose of the surface of the leased lands under existing law or laws hereafter enacted, insofar as said surface is not necessary for the use of the lessee in the extraction and removal of the oil and gas therein, or to dispose of any resource in such lands which will not unreasonably interfere with operations under the lease.

(c) *Monopoly and fair prices.*—Full power and authority to promulgate and enforce all orders necessary to insure the sale of the production of the leased lands to the United States and to the public at reasonable prices, to protect the interests of the United States, to prevent monopoly, and to safeguard the public welfare.

(d) *Helium.*—Pursuant to section 1 of the act, and section 1 of the act of March 3, 1927 (44 Stat. 1387), as amended, the ownership and the right to extract helium from all gas produced under this lease, subject to such rules and regulations as shall be prescribed by the Secretary of the Interior. In case the lessee elects to take the helium the lessee shall deliver all gas containing same, or portion thereof desired, to the lessor at any point on the leased premises in the manner required by the lessor, for the extraction of the helium in such plan or reduction works for that purpose as the lessor may provide, whereupon the residue shall be returned to the lessee with no substantial delay in the delivery of gas produced from the well to the purchaser thereof. The lessee shall not suffer a diminution of value of the gas from which the helium has been extracted, or less otherwise, for which he is not reasonably compensated, save for the value of the helium extracted. The lessor further reserves the right to erect, maintain, and operate any and all reduction works and other equipment necessary for the extraction of helium on the premises leased.

(e) *Taking of royalties.*—All rights pursuant to section 36 of the act, to take royalties in amount or in value of production.

(f) *Canvas.*—All rights pursuant to section 40 of the act to purchase casing, and lease or operate valuable water wells.

Sec. 4. Drilling and producing restrictions.—It is agreed that the rate of prospecting and developing and the quantity and rate of production from the lands covered by this lease shall be subject to control in the public interest by the Secretary of the Interior, and in the exercise of his judgment the Secretary may take into consideration, among other things, Federal laws, State laws, and regulations issued thereunder, or lawful agreements among operators regulating either drilling or production, or both. After unitization, the Secretary of the Interior, or any person, committee, or State or Federal officer or agency so authorized in the unit plan, may alter or modify from time to time, the rate of prospecting and development and the quantity and rate of production from the lands covered by this lease.

Sec. 5. Surrender and termination of lease.—The lessee may surrender this lease or any legal subdivision thereof by filing in the proper land office a written relinquishment, in triplicate, which shall be effective as of the date of filing subject to the continued obligation of the lessee and his surety to make payment of all accrued rentals and royalties and to place all wells on the land to be relinquished in condition for suspension or abandonment in accordance with the applicable lease terms and regulations.

Sec. 6. Purchase of materials, etc., on termination of lease.—Upon the expiration of this lease, or the earlier termination thereof pursuant to the last preceding section, the lessee shall have the privilege at any time within a period of 90 days thereafter of removing from the premises all machinery, equipment, tools, and materials other than improvements needed for producing wells. Any materials, tools, appliances, machinery, structures, and equipment subject to removal as above provided, which are allowed to remain on the leased lands shall become the property of the lessor on expiration of the 90-day period or such extension thereof as may be granted because of adverse climatic conditions throughout said period: *Provided*, That the lessee shall remove any or all of such property where so directed by the lessor.

Sec. 7. Proceedings in case of default.—If the lessee shall not comply with any of the provisions of the act or the regulations thereunder or of the lease or make default in the performance or observance of any of the terms hereof except payment of rentals, and such default shall continue for a period of 30 days after service of written notice thereof by the lessor, this lease may be canceled by the Secretary of the Interior in accordance with section 31 of the act, except that if this lease covers lands known to contain valuable deposits of oil or gas, the lease may be canceled only by judicial proceedings in the manner provided in section 31 of the act; but this provision shall not be construed to prevent the exercise by the lessor of any legal or equitable remedy which the lessor might otherwise have. Upon cancellation of this lease, any casing material or equipment determined by the lessor to be necessary for use in purging or preserving any well drilled on the leased land shall become the property of the lessor. A waiver of any particular cause of forfeiture shall not prevent the cancellation and forfeiture of this lease for any other cause of forfeiture, or for the same cause occurring at any other time.

Sec. 8. Heirs and successors-in-interest.—It is further agreed that each obligation hereunder shall extend to and be binding upon, and every benefit hereof shall inure to, the heirs, executors, administrators, successors, or assigns of the respective parties hereto.

Sec. 9. Unlawful interest.—It is also further agreed that no Member of, or Delegate to, Congress, or Resident Commissioner, after his election or appointment, or either before or after he has qualified and during his continuance in office, and that no officer, agent, or employee of the Department of the Interior, except as provided in 43 CFR 7.4 (a) (1), shall be admitted to any share or part in this lease or derive any benefit that may arise therefrom; and the provisions of Sec. 3741 of the Revised Statutes of the United States, as amended (41 U. S. C. Sec. 22) and Secs. 431, 432 and 433, Title 18 U. S. Code, relating to contracts, enter into and form a part of this lease so far as the same may be applicable.

INSTRUCTIONS

A. GENERAL INSTRUCTIONS

1. This offer must be filled in on a typewriter or printed plainly in ink and must be signed in ink.

2. This form is to be used in offering to lease noncompetitively public domain lands or oil and gas deposits reserved to the United States in disposals of such lands for the purpose of drilling, mining, extracting, removing and disposing of oil and gas deposits, except helium. This form should not be used in offering to lease acquired lands or lands on a known geologic structure of a producing oil or gas field.

3. Offers to lease may be made by individuals 21 years of age or over who are citizens of the United States, and by corporations, partnerships or associations.

4. The offer must be prepared in quintuplicate and filed in the proper land office. The term "filing" means the actual receipt of the offer in the proper land office. If the land is in a State for which there is no land office, the offer must be filed with the Bureau of Land Management, Department of the Interior, Washington 25, D. C. Sec. 43 CFR 192.42(b). If less than five copies are filed, the offeror will have 30 days from the date of first filing to file the other required copies, failing in which the offer will be rejected and returned to the offeror and will afford no priority.

5. The offeror shall mark one of the copies first filed at the top with the word "original." If that is not done, the manager will so mark one copy. If there is any variation in the land descriptions among the five copies, the one marked "original" shall govern as to the lands covered by the lease.

6. If additional space is needed in furnishing any of the required information it should be prepared on additional sheets, initialed and attached and made part of the offer to lease, such additional sheets to be regarded as such copy of the form submitted.

7. If any of the land described in item 2 of the offer is open to oil and gas lease filing while the offer is filed but is omitted from the lease for any reason and thereafter becomes available for leasing to the offeror, the original lease will be amended to include the omitted land, unless, before the issuance of the amendment on Form 4-1163, the land office receives the withdrawal of the offer as to such land or an election to receive a separate lease to be dated in accordance with 43 CFR 192.43 in which case such separate lease will be issued. If the lease is amended the rental charged and the lease term will be the same as though the added land had been included in the original lease when it was issued.

8. As an incident to the assignment of the whole interest in all or any part of the lease, the lessee may retain the whole interest in all or any part of the offer. As an incident to the assignment of an undivided fractional interest in the whole lease, the lessee may retain an undivided fractional interest in the whole offer. Applications for approval of assignments of an offer must include a statement that the assignee agrees to be bound by the offer to the extent it is assigned and must be signed by the assignee. In other instances assignments of the offer will not be approved prior to the issuance of a lease for the lands or deposits covered by said assignments.

9. The offer will be rejected and returned to the offeror and will afford the applicant no priority if: (a) The land description is insufficient to identify the lands or the lands are not entirely within a 6-mile square. (b) The total acreage exceeds 2,560 acres, except where the rule of approximation applies or is less than 640 acres or the equivalent of a section and is not within the exceptions in 43 CFR 192.42 (d). This does not apply where the total acreage is in error by not more than 10 percent. (c) The full filing fee and the first year's rental do not accompany the offer, the rental payment to be for the total acreage if known, and if not known, for the total acreage computed on the basis of 40 acres for each smallest legal subdivision, except where the rental is in error by not more than 10 percent. (d) The offer is signed by an agent in behalf of the offeror and the offer is not accompanied by a statement over the offeror's own signature with respect to holdings and citizenship and by the statements and evidence required by 43 CFR 192.43 (c) (4). (e) The offer is signed by a guardian or trustee in behalf of a minor and is not accompanied by the evidence required by 43 CFR 192.42 (c) (5). (f) More than five copies of the offer are filed and the copies lacking are not received in the land office before the expiration of 30 days from the date of receipt of the copies first filed, or (g) There is noncompliance with item 5 (a) and 5 (c) of the Special Instructions. The offeror will be given an opportunity to file a new offer within 30 days from service of the rejection, and the fee and rental payments on the old offer will be applied to the new offer if the new offer shows the serial and receipt numbers of the old offer. The advance rental will be returned unless within the 30-day period another offer is filed.

B. SPECIAL INSTRUCTIONS [1]

Item 2.—Total area of land requested should be shown in acres in space provided at bottom of page. This area, except where the rule of approximation applies, shall not exceed 2,560 acres or be less than 640 acres or the equivalent of a section, as provided in 43 CFR 192.42 (d). All of the land must be within a 6-mile square. The lands requested if surveyed should be described by legal subdivisions, showing meridian, State, township, range, and section, and if unsurveyed, by metes and bounds connected by courses and distance with some corner of the public land survey. Where possible the approximate legal subdivisions of unsurveyed lands should be stated.

Item 3.—This space is not to be filled in. When lease is issued this space will contain the identification of the leased area and total acreage.

Item 4.—The total amount remitted should include a $10 filing fee and the first year's rental of the land requested at the rate of 50 cents an acre or fraction of an acre. The $10 filing fee is retained as a service charge, even in those cases where the offer to lease is completely rejected. In order to protect the offeror's priorities with respect to the land requested, it is important that the rental payment submitted with the offer be sufficient to cover all the land requested at the rate of 50 cents an acre or fraction thereof. If the land requested includes lots or irregular quarter-quarter sections, the exact area of which is not known to the offeror, rental may be submitted for the purpose of the offer on the basis of each such lot or quarter-quarter section containing 40 acres. If the offer is withdrawn in whole or in part before a lease is issued or if the offer is rejected in whole or in part, the rental remitted for the parts withdrawn or rejected will be returned. Where at the time the lease is to be issued, the land applied for or any part of it is within a known geologic structure of a producing oil or gas field, the lessee will be billed for the additional rental of 50 cents an acre on all the leased land as the yearly rental on such lands is $1 per acre. In Alaska, the rental payment to accompany the offer should be at the rate of 25 cents per acre.

Item 5 (a).—Offeror will indicate whether a citizen by birth or naturalization. If production is obtained under this lease or allocated to it, the citizenship status of the lessee will be verified.

If offeror is an unincorporated association (including a partnership), the offer must be accompanied by a statement giving the same showing as to citizenship and holdings of its members as required of an individual.

If offeror is a corporation it must submit a statement containing the following information: the State in which it is incorporated; that it is authorized to hold oil and gas leases and that the officer executing the lease is authorized to act on behalf of the corporation in such matters; the percentage of the voting stock and of all of the stock owned by aliens or those having addresses outside the United States. Where such ownership is over 10 percent, additional information may be required by the Bureau before the lease is issued or when production is obtained. If any appreciable percentage of the stock is held by aliens of the exempted class the application will be denied. If 20 percent or more of the stock of any class is owned or controlled by or on behalf of any one stockholder a separate showing of his citizenship and holdings must be furnished.

Item 5 (b).—Acreage included in unit plans and certain section 18 and 19 leases is not chargeable.

Item 5 (c).—Whenever applicable the stipulations referred to will be made a part of this lease and will be furnished the lessee with the lease when issued. The forms covering them with a brief description are as follows: 4-216 Stipulations for lands where the surface control is under the jurisdiction of the Department of Agriculture; 4-407 Lands potentially irrigable; 4-407 (a) Lands within the flow limits of a reservoir site; and 4-407 (b) Lands within the drainage area of a constructed reservoir. Whenever other stipulations are necessary, lessee will be required to agree to them before the issuance of the lease.

Item 5 (e).—If there are settlers attach a sheet giving the name and post-office address of each and description of the lands claimed by metes and bounds and approximate legal subdivision.

[1] Items numbered according to numbers on offer form.

U. S. GOVERNMENT PRINTING OFFICE 16—63057-7

AGO 570642

FORM NO. DL-1

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

LEASE NO. ADL 00583

Competitive Oil and Gas Lease

THIS LEASE, dated the 1st day of January, 19 60, is made by and between the State of Alaska, acting by and through the Director of the Division of Lands of the Department of Natural Resources, hereinafter called "Lessor", and

THE OHIO OIL COMPANY, an Ohio corporation

UNION OIL COMPANY OF CALIFORNIA, a California corporation

hereinafter called "Lessee", whether one or more.

1. GRANT. For and in consideration of a cash bonus and the first year's rental, the receipt of which is hereby acknowledged, and of the rentals, royalties, covenants, and conditions herein contained on the part of the Lessee to be paid, kept and performed, and subject to the conditions and reservations herein contained, Lessor does hereby grant and lease unto Lessee, exclusively, without warranty, for the sole and only purposes of exploration, development, production, processing and marketing of oil, gas, and associated substances produced therewith, and of installing pipe lines and structures thereon to find, produce, save, store, treat, process, transport, take care of and market all such substances, and for drilling water wells and taking underground and surface water for use in its operations thereon and for housing and boarding employees in its operation thereon, the following described tract of land in Alaska: All of projected sections 30 and 31, T. 5 N., R. 11 W., S. M., lying westerly of the coast line and all of projected sections 25 and 36, T. 5 N., R. 12 W., S. M., as per protraction sheet Grid No. S-13-11 approved Sept. 15, 1959, being designated also as parcel No. S-13-11-1

containing 1,731 acres, more or less, hereinafter called "said land".

For the purposes of this lease, said land contains 4 legal subdivisions, as shown on the plat of said land attached hereto, marked Exhibit A and by this reference made a part of this lease.

If said land is described above by protracted legal subdivisions, and Lessor hereafter causes said land to be surveyed under the public land rectangular system, the boundaries of said land shall be those established by such survey, when approved, subject, however, to the provisions of the regulations relating to such surveys.

2. "OIL AND GAS". "Oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced and saved in liquid form at the well by ordinary production methods. "Gas" means all natural gas and all hydrocarbons produced at the well not defined herein as oil. "Associated substances" means all substances produced in association with oil or gas and not defined herein as oil or gas.

3. TERM. This lease is issued for an initial primary term of five years from the date hereof, subject to extension as provided in Paragraph 4 hereof, and shall continue so long thereafter as oil and gas or either or any of them are produced in paying quantities from said land; provided, that this lease may be extended beyond its primary term as provided in Paragraph 5 hereof and shall not expire under the conditions set forth in Paragraphs 6, 7, and 8 hereof.

4. EXTENSION BY SUSPENSION OF OPERATIONS. If, prior to the expiration of the primary term, Lessor, in the interest of conservation, directs or assents to the suspension of all operations and production, if any, hereunder, the primary term will be extended by adding the period of suspension thereto.

5. EXTENSION BY UNIT PRODUCTION. This lease shall without application be extended beyond its primary term if upon or prior to the expiration date of such term the lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, production of oil or gas is had in paying quantities under the agreement. and a portion of such production is allocated to said land under the agreement. In such event this lease shall continue in effect so long as it remains subject to such agreement and actual production under said agreement is allocated to said land.

6. EXTENSION BY DRILLING. If production shall have been obtained in paying quantities during the primary term, and if, at the end of the primary term, or at any time prior to the end of the primary term, such production shall have ceased from any cause, or in the event production shall at any time or times after the expiration of the primary term cease from any cause, then this lease shall not terminate if the Lessee commences drilling or reworking operations (either in a well from which such production has ceased or in a new well) within sixty days after ther cessation of production, and the lease shall remain in full force and effect so long as operations are prosecuted with reasonable diligence or are suspended under Paragraph 27 hereof; and, if such drilling or reworking operations result in the production of oil or gas, the lease shall remain in full force and effect so long as oil or gas is produced therefrom in paying quantities.

7. EXTENSION BY SHUT-IN PRODUCTION. If, upon the expiration of the primary term or at any time or times thereafter, there is on said land a well capable of producing oil or gas in paying quantities, this lease shall not expire because Lessee fails to produce the same unless Lessor gives notice to Lessee allowing a reasonable time, which shall not be less than sixty days, after such notice to place the well on a producing status, and Lessee fails to do so; provided, that after such status is established such prdouction shall continue on the said land unless and until suspension of production is allowed by Lessor.

8. EXTENSION BY SUSPENSION OF PRODUCTION. This lease shall not expire because of any suspension of operations in or upon or production from said land if such suspension is made under any order or with the consent of Lessor.

9. RENTAL. This lease shall termination on any anniversary date hereof prior to the completion on said land of a well capable of producing oil or gas in paying quantities, unless on or before said anniversary date Lessee shall pay or tender to Lessor as annual rental a sum equal to $1.00 per acre, or fraction thereof, then included in this lease, or unless such annual rental has been waived or suspended as provided in Paragraph 13 of this lease. If Lessor's office is not open for business on the anniversary date, the time for payment is extended to include the next day on which said office is open for business. Any rental paid for any one lease year shall be credited on any royalty for that year.

10. MINIMUM ROYALTY. Commencing with the lease year beginning on or after completion on said land of a well capable of producing oil or gas in paying quantities, Lessee shall pay Lessor, at the expiration of each lease year, in lieu of rental a minimum royalty equal to $1.00 per acre, or fraction thereof, then included in this lesae, or the difference between the actual royalty paid on production during the year if less than $1.00 per acre and the prescribed minimum royalty.

11. ROYALTY ON PRODUCTION. Except for oil and gas used on said land for development and production or unavoidably lost, Lessee shall pay Lessor as royalty the following:

(a) On oil 12½ per cent in amount or value of the oil produced and saved and removed or sold from said land.

(b) On gas 12½ per cent in amount or value of the gas produced and saved and sold or used off said land or used for the extraction of natural gasoline or other products therefrom.

(c) On associated substances 12½ percent in amount or value of such substances produced and saved and removed or sold from said lands.

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12. REDUCTION OF ROYALTY RATES FOR DISCOVERY. If Lessee shall drill on said land and make the first discovery of oil or gas in commercial quantities in any geological structure, the royalty rate under this lease shall, instead of the rates prescribed in Paragraph 11, be five per cent for a period of ten years following the date of such discovery, and thereafter the royalty rates shall be those prescribed in Paragraph 11. If this lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, the five per cent royalty rate shall apply t all, but only, the production allocated to this lease under such agreement.

13. REDUCTION OF RENTAL AND ROYALTY. Rental or minimum royalty may be waived, suspended, or reduced, or royalty may be reduced on all of said land or any tract or portion thereof segregated for royalty purposes if Lessor finds that such relief is necessary for the purpose of encouraging the greatest ultimate recovery of oil or gas and is in the interest of conservation of natural resources and either that such relief is necessary in order to promote development or that the lease cannot be successfully operated under the terms provided herein.

14. ROYALTY IN KIND. Whenever, at the option of Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, Lessor elects to take its royalty in kind, Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon) to Lessor or to such individual, firm, or corporation as Lessor may designate all royalty oil and/or gas produced and saved from said land. Such oil and/or gas shall be in good and merchantable condition. Lessee shall, if necessary, furnish storage for royalty oil free of charge for thirty days after the end of the calendar month in which the oil is produced from said land; provided, that Lessee shall not be held liable for loss or destruction of royalty oil and/or gas from causes beyond Lessee's reasonable control. Should Lessee dehydrate or clean the oil or gas produced from said land, Lessee shall be entitled to an allowance of the actual cost of dehydrating or cleaning said royalty oil or gas.

15. ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts of gross production.

16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or, (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

17. PAYMENTS. All payments to Lessor under this lease shall be made payable to the Department of Revenue of the State of Alaska and shall be tendered to Lessor at the place designated under Paragraph 43 for giving notices to Lessor.

18. OFFSET WELLS. Lessee shall drill such wells as a reasonably prudent operator would drill to protect Lessor adequately from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas should be produced in a well on other land not owned by Lessor or on which Lessor receives a lower rate of royalty than the royalty under this lease, which well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and such well shall produce oil or gas in paying quantities for a period of thirty consecutive days, and if, after notice to Lessee and an opportunity to be heard, Lessor finds that production from such well is draining lands then subject ot this lease, Lessee shall within 120 days after written demand by Lessor begin in good faith and prosecute diligently drilling operations for an offset well on said land. In lieu of drilling any well required by this paragraph, Lessee may with Lessor's consent compensate Lessor in full each month for the estimated loss of royalty through drainage in the amount determined by lessor.

19. OTHER WELLS. This lease contemplates the reasonable development of said land for oil and gas as the facts may justify. Upon discovery of oil or gas in paying quantities on said land, Lessee shall drill such wells as a reasonably prudent operator would drill having due regard for the interests of Lessor as well as the interests of Lessee.

20. DILIGENCE; PREVENTION OF WASTE. Lessee shall exercise reasonable diligence in drilling, producing, and operating wells on said land unless consent to suspend operations temporarily is granted by Lessor; shall carry on all operations hereunder in a good and workmanlike manner in accordance with approved methods and practices, having due regard for the prevention of waste of oil and gas and the entrance of water to the oil and gas bearing sands or strata to the destruction or injury of such deposits and the preservation and conservation of the property for future productive operations; shall use reasonable care and all proper safeguards to prevent the pollution of water; shall plug securely in an approved manner any well before abandoningit; shall allow Lessor to inspect all operations at any time; shall carry out at Lessee's expense all reasonable orders and requirements of Lessor relative to the prevention of waste and the preservation of said land, and on failure of Lessee so to do, Lessor shall have the right together with any other recourse available to it to enter on said land to repair damage or prevent waste at Lessor's expense; and shall abide by and conform to valid applicable rules and regulations of the Alaska Oil and Gas Conservation Commission and the regulations of Lessor relating to the matters covered by this paragraph in effect on the effective date hereof or hereafter in effect if not inconsistent with any specific provisions of this lease.

21. WELL LOCATIONS. Lessee shall within five days after spudding in a well advise Lessor in writing of the location and date of spudding of said well.

22. APPROVAL OF PLANS. Lessee shall not place into actual operation any plan or method for the purpose of stimulating or increasing production on said land other than plans and methods in common use without first having obtained the written approval of Lessor.

23. LOGS AND RECORDS. An electric log or radioactive log, if taken, and a descriptive geologic sample log, if taken, and a record of all tests run for each well drilled on said land, together with a plat showing the exact location of each such well, shall be filed with Lessor within sixty days after such well has been completed or abandoned; provided, that such logs and records of an exploratory well, whether completed as a producer or abandoned as a dry hole, may be filed at any time within eighteen months after the completion or abandonment of such well. Any and all information filed by Lessee with Lessor in connection with this lease shall be available at all times for the confidential use of Lessor for the purpose of enforcing compliance with the terms, covenants, and conditions of this lease and the regulations of Lessor but shall not be open for inspection by any person other than officers or employees of Lessor and persons performing any function or work assigned to them by Lessor except upon the written consent of Lessee. Notwithstanding any other provision hereof, said information may be disclosed to any person where such disclosure is reasonably necesary for the administration of the functions, responsibilities, and duties vested by law in the Commissioner of the Department of Natural Resources or in the Division of Lands or the Director thereof, including but not limited to functions, responsibilities. and duties arising in connection with any litigation or administrative adjudication relating to this lease or to the rights, duties, and obligations arising hereunder.

24. RECORDS. Lessee shall keep and have in its possession books and records showing the production and disposition of all oil and gas produced from said land and shall permit Lessor or its agents at all reasonable hours to examine the same. Such records and reports of production shall be based upon such methods and techniques as shall insure the most accurate figures reasonably available without requiring the Lessee to provide separate tankage for each well.

25. DAMAGES. Section 2 of Article VII of the Alaska Land Act, Chapter 169, S.L.A., 1959, provides in part that no rights under reservations contained in certain leases or grants of Alaska [illegible] shall be exercised by Lessor or its Lessee until provision has been made for pay to the owner of the land upon which the reserved rights are sought to be exercised full payment for all damages sustained by said owner by reason of entering upon said land; provided, that if said owner for any cause whatever refuses or neglects to settle said damages, Lessor or its Lessee shall have the

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age that may become payable under said statutory provisions and to indemnify Lessor and hold it harmless from and against any claims, demands, liabilities and expenses arising from or in connection with such damage. The furnishing of a bond in compliance with this L[illegible] will be regarded by Lessor as a suffi[illegible]provision for the payment of all damage that may become payable under said statutory provisions.

26. BONDS.

(a) Lessee shall maintain the bond furnished prior to the issuance of this lease in an amount equal to at least $2.00 per acre or fraction thereof contained in said land but not less than $1,000.00.

(b) Before beginning drilling operations on said land Lessee must have furnished and shall maintain a bond in an amount of at least $5,000.00.

(c) Lessee may, in lieu of the foregoing, furnish and maintain a statewide bond in the amount of $100,000.00

(d) Lessor may, after notice to Lessee and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified above in this paragraph where such greater amount is justified by the nature of the surface and its uses and improvements in the vicinity of said land and the degree of the risks involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph but will be considered by Lessor in determining the need for and the amount of any additional bond under this subparagraph.

(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

27. ACTS OF GOD. Should Lessee be prevented from complying with any expressed or implied covenant of this lease, from conducting drilling operations thereon, or from producing or marketing oil or gas from said land after efforts made in good faith, by reason of war, riots, acts of God, severe weather in the area of said land, acts of governmental authorities, failure or lack of adequate transportation facilities, or any other cause beyond Lessee's reasonable control whether similar to those enumerated or not, then while so prevented and for a reasonable time thereafter within which to resume operations, Lessee's obligation to comply with such covenant shall be suspended and Lessee shall not be liable for damages for failure to comply therewith. If drilling or reworking operations are suspended by virtue of this paragraph and the prosecution of such operations would have had the effect of preventing the expiration or termination of this lease, then this lease shall not terminate during the period which the obligation to perform such operations is suspended under this paragraph; provided, however, that nothing in this paragraph shall be construed to suspend the payment of rentals or of minimum royalties.

28. SUSPENSION. Lessor may from time to time direct or assent to the suspension of production or other operations or both under this lease is such action is necessary or justified in the interest of conservation.

29. RESERVATIONS. Lessor reserves the right to dispose of the surface of said land to others subject to this lease, and the right to authorize others by grant, lease, or permit subject to this lease and under such conditions as will prevent unnecessary or unreasonable interference with the rights of Lessee and operations under this lease, to enter upon and use said land:

(a) To explore for oil or gas by geological or geophysical means including the drilling of shallow core holes or stratigraphic tests to a depth of not more than 1,000 feet.

(b) To explore for, develop and remove natural resources other than oil, gas, and associated substances on or from said land.

(c) For nonexclusive easements and rights of way for any lawful purpose including shafts and tunnels necessary or appropriate for the working of said land or other lands for natural resources other than oil, gas or associated substances.

(d) For well sites and well bores of wells drilled from or through said land to explore for or produce oil, gas, and associated substances in and from other lands.

(e) For any other purpose now or hereafter authorized by law and not inconsistent with the rights of Lessee under this lease.

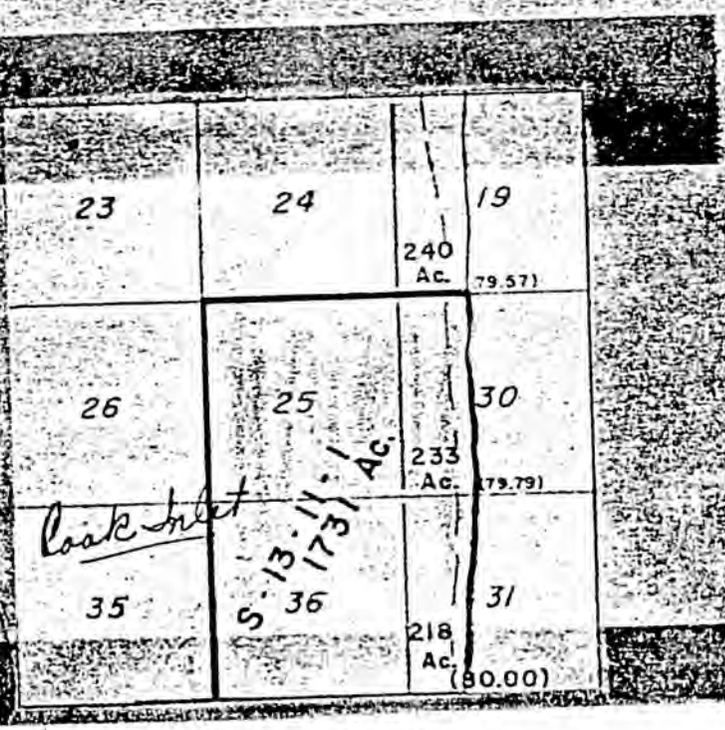
30. UNDERGROUND STORAGE. This lease does not authorize the subsurface storage of oil or gas except as a necessary incident to recycling pressure maintenance, repressuring, or other similar operations designed to increase the ultimate recovery of oil or gas or prevent the waste of oil or gas produced from said land or from any unit area of which the said land is a part. Lessor reserves the right to authorize the subsurface storage of oil or gas in said land by Lessee or by others in order to avoid waste or to promote conservation of natural resources and upon such conditions as will prevent unnecessary or unreasonable interference with the rights and operations of Lessee under this lease, including conditions prohibiting the storage of oil or gas without the consent of Lessee in any reservoir covered by this lease capable of producing oil or gas in paying quantities.

31. ASSIGNMENTS. This lease or any undivided interest herein may with the approval of Lessor be assigned or subleased as to said land or any one or more legal subdivisions included therein, or any separate and distinct zone or geological horizon underlying said land or such one or more legal subdivisions, to any person or persons qualified to hold a lease. No transfer of any interest in this lease including assignments of working or royalty interests and operating agreements and subleases shall be binding upon Lessor unless approved by Lessor. Lessee shall remain liable for all obligations under this lease accruing prior to the approval of such transfer. Approval of transfer of this lease or an interest therein will not be denied except (1) for failure to comply with the regulations, (2) in the discretion of Lessor, where the transfer covers any distinct zone or geological horizon, or (3) where Lessor determines that the best interests of Lessor justify such action. Applications for approval of a transfer under this paragraph must comply with the regulations and must be filed within ninety days after the date of final execution of the instrument of transfer. Where a transfer is made of all or a part of Lessee's interest in and to a portion of the acreage in said land the assigned acreage shall, at the option of Lessor, or may upon request of the transferee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

32. UNITIZATION. Whenever determined and certified by Lessor to be necessary or advisable in the public interest for the purpose of properly conserving the natural resources of any oil or gas pool, field or like area or any part thereof, which includes or underlies said land or any part thereof, Lessee may unite with other Lessees of Lessor or with others owning or operating lands not belonging to Lessor including lands belonging to the United States and with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the development or operation of the pool or field or like area or part thereof. Lessee shall within thirty days after demand by Lessor subscribe to such a cooperative or unit agreement, which agreement shall be reasonable and shall adequately protect all parties in interest including Lessor. Lessor may with the consent of Lessee establish, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of this lease if committed to any such cooperative or unit agreement and may make such regulations with reference to this lease with the like consent of Lessee in connection with the institution and operation of any such cooperative or unit agreement as Lessor may determine to be necessary or proper to secure the proper protection of the public interest. If a portion of said land is committed to an approved or prescribed unit agreement, the committed acreage shall at the option of Lessor and may upon the request of Lessee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

3. SURRENDER. Lessee may at any time make and file with Lessor a written surrender of all rights under this lease or any portion thereof comprising one or more legal subdivisions or, with the consent of Lessor, of any separate and distinct Zone or geological horizon underlying said lands or such one or more legal subdivisions thereof. Such a surrender shall be effective as of the date of filing subject to the continued obligations of Lessee and his surety to make payment of all royalties theretofore accrued and to place all wells on the surrendered land or in the surrendered zones or horizons in condition satisfactory to Lessor for suspension or abandonment; thereupon, Lessee shall be released from all other obligations accrued or to accrue under this lease with respect to the surrendered lands, zones, or horizons.

MAP OF TRACT AS INDICATED ON PROTRACTION
GRID OF THE COOK INLET SHELIKOF STRAIT SERIES



S-13-11-1

Fractional Sec. 30		233
" Sec. 31		218
T. 5N R. 11W, S.M.		
Sec. 25 (All)		640
Sec. 36 (All)		640
T. 5N R. 12W, S.M.	Total	1731

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DEFAULT; TERMINATION. Whenever Lessee fails to comply with any of the provisions of this lease other e payment of rental and Lessee fails within sixty days after written notice of such default to commence to remedy reafter prosecute diligently operations to remedy such default, Lessor may cancel this lease if at that time no well on said land capable of producing oil or gas in paying quantities. If at such time there is on said land capable of producing oil or gas in paying quantities, this lease may be cancelled only by judicial proceedings. vent of any cancellation under this paragraph, Lessee shall have the right to retain under this lease any and all or producing wells as to which no default exists together with a parcel of land surrounding each such well and such rights of way through said land as may be reasonably necessary to enable Lessee to drill and operate tained well or wells.

EXCESS AREA. If for any reason said land includes more acreage than the maximum permitted under aws and/or regulations, this lease shall not be void but the acreage included in said land shall be reduced to mitted maximum. Whenever Lessor determines that this lease so exceeds the permitted acreage and notifies stating the amount of acreage that must be eliminated, Lessee may within sixty days after such notice surrender more legal subdivisions included in said lands comprising at least the amount of acreage that must be eliminated. surrender is not filed within such sixty days Lessor may terminate this lease as to the acreage that must be elim- mailing notice of such termination to Lessee describing the parcel or parcels eliminated. Such a notice shall effect of terminating this lease as to the parcel or parcels described in such notice.

RIGHTS ON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion ands, Lessee shall have the privilege at any time within a period of six months thereafter, or such extension as may be granted by Lessor, of removing from said land or portion thereof all machinery, equipment, tools, terials other than improvements needed for producing wells. Any materials, tools, appliances, machinery, struc- d equipment subject to removal as above provided which are allowed to remain on said land or portion thereof come the property of Lessor upon expiration of such period; provided, that Lessee shall remove any and all of operties when so directed by Lessor. Subject to the foregoing, Lessee shall deliver up said lands or such portion ons thereof in good order and condition.

INTEREST IN LAND. It is the intention of the parties that the rights vested in Lessee by this lease shall e an interest in real property in said land.

LESSOR INTEREST. If Lessor owns a lesser interest in the oil and gas deposits in said land than the entire ivided fee simple estate, then the royalties and rentals herein provided shall be paid Lessor only in the proportion ch its interest bears to the whole and undivided fee.

CONDITIONAL LEASE. If all or a part of said land is land that has been selected by the Lessor under laws nited States granting lands to Lessor, but such land has not been patented to Lessor by the United States, then e is a conditional lease as provided by law until such patent become effective. If for any reason such a selec- ot finally approved or such a patent does not become effective, and rental, royalty or minimum royalty pay- ade to Lesosr under this lease will not be refunded.

DRILLING OPERATIONS. As used in this lease "drilling operations" mean any work or actual operations ken or commenced in good faith for the purpose of carrying out any of the rights, privileges or duties of Lessee is lease, followed diligently and in due course by the construction of a road or derrick and/or other necessary s for the drilling of an oil or gas well, and by the actual operation of drilling in the ground. Any such work tions preliminary to drilling in the ground may be undertaken either on said land or in the vicinity of said land rder Lessee shall see fit.

RULES AND REGULATIONS. As used in this lease "regulations" mean the applicable and valid oil and ng regulations of the Commsisioner of the Department of Natural Resources in effect on the effective date of e unless otherwise specified.

INTERPRETATION. As used in this lease words which are defined in the regulations have the meaning as- y such definition except where the context clearly requires a different meaning. The paragraph headings are rt of this lease and are inserted only for convenience.

NOTICES. Any notice required or permitted under this lease shall be in writing and shall be given by reg- r certified mail, return receipt requested, addressed as follows:

Lessor:

Director, Division of Lands
State of Alaska
333 "D" Street
Anchorage, Alaska

To Lessee:

THE OHIO OIL COMPANY
650 South Flower Street
Los Angeles 17, California

notice shall be deemed given when delivered to the foregoing address. Either party may change the address such notices are to be sent, by notice given in accordance with this paragraph.

HEIRS AND ASSIGNS. Subject to the other provisions of this lease, the covenants, conditions, and agreements d in this lease shall extend to and be binding upon the heirs, executors, administrators, successors, or assigns r and Lessee.

WITNESS WHEREOF the parties have executed this lease.

THE OHIO OIL COMPANY

By George Bowman
Division Manager

UNION OIL COMPANY OF CALIFORNIA

By
Attorney-in-Fact
LESSEE

STATE OF ALASKA

By
Director, Division of Lands
LESSOR

AGO 570647

ITED STATES OF AMERICA)
) ss.
OF ALASKA)

certifies that on the 21st day of September, 1960 before me a public in and for the State of Alaska, duly commissioned and sworn, personally appeared ROSCOE E. BELL, known and known to me to be the person described in and who executed hte foregoing lease on behalf of the Alaska as Director of the Division of Lands, Department of Nautral Resources. The said ROSCOE E. BELL, said lease in my presence and, after being duly sworn according to law, stated to me under oath that he is ctor of the Division of Lands, Department of Natural Resources and has authority pursuant to law to execute going lease as such Director on behalf of the State of Alaska, acting through the Division of Lands, Department al Resources and that he executed the same freely and voluntarily as the free and voluntary act, and lease of State of Alaska and for the Division of Lands, Department of Natural Resources.

NESS my hand and official seal the day and year in this certificate first above written.

Notary Public in and Alaska

My Commission expires 10-23-63

FORM NO. DL-1

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

LEASE NO. ADL 09583

Competitive Oil and Gas Lease

THIS LEASE, dated the 1st day of January, 19 60, is made by and between the State of Alaska, acting by and through the Director of the Division of Lands of the Department of Natural Resources, hereinafter called "Lessor", and

THE OHIO OIL COMPANY, an Ohio corporation
UNION OIL COMPANY OF CALIFORNIA, a California corporation

hereinafter called "Lessee", whether one or more.

1. GRANT. For and in consideration of a cash bonus and the first year's rental, the receipt of which is hereby acknowledged, and of the rentals, royalties, covenants, and conditions herein contained on the part of the Lessee to be paid, kept and performed, and subject to the conditions and reservations herein contained, Lessor does hereby grant and lease unto Lessee, exclusively, without warranty, for the sole and only purposes of exploration, development, production, processing and marketing of oil, gas, and associated substances produced therewith, and of installing pipe lines and structures thereon to find, produce, save, store, treat, process, transport, take care of and market all such substances, and for drilling water wells and taking underground and surface water for use in its operations thereon, and for housing employees [illegible]

All that portion of projected sections 1 and 12 lying westerly of the coast line and all of projected sections 2 and 11, T.4N., R.12W., S.M., as per protraction sheet grid S-13-14 approved September 14, 1959, being designated also as parcel No. S-13-14-1.

[illegible] Lessor hereafter causes said land to be surveyed under the public land rectangular system, the boundaries of said land shall be those established by such survey, when approved, subject, however, to the provisions of the regulations relating to such surveys.

2. "OIL AND GAS". "Oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced and saved in liquid form at the well by ordinary production methods. "Gas" means all natural gas and all hydrocarbons produced at the well not defined herein as oil. "Associated substances" means all substances produced in association with oil or gas and not defined herein as oil or gas.

3. TERM. This lease is issued for an initial primary term of five years from the date hereof, subject to extension as provided in Paragraph 4 hereof, and shall continue so long thereafter as oil and gas or either or any of them are produced in paying quantities from said land; provided, that this lease may be extended beyond its primary term as provided in Paragraph 5 hereof and shall not expire under the conditions set forth in Paragraphs 6, 7, and 8 hereof.

4. EXTENSION BY SUSPENSION OF OPERATIONS. If, prior to the expiration of the primary term, Lessor, in the interest of conservation, directs or assents to the suspension of all operations and production, if any, hereunder, the primary term will be extended by adding the period of suspension thereto.

5. EXTENSION BY UNIT PRODUCTION. This lease shall without application be extended beyond its primary term if upon or prior to the expiration date of such term the lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, production of oil or gas is had in paying quantities under the agreement, and a portion of such production is allocated to said land under the agreement. In such event this lease shall continue in effect so long as it remains subject to such agreement and actual production under said agreement is allocated to said land.

6. EXTENSION BY DRILLING. If production shall have been obtained in paying quantities during the primary term, and if, at the end of the primary term, or at any time prior to the end of the primary term, such production shall have ceased from any cause, or in the event production shall at any time or times after the expiration of the primary term cease from any cause, then this lease shall not terminate if the Lessee commences drilling or reworking operations (either in a well from which such production has ceased or in a new well) within sixty days after ther cessation of production, and the lease shall remain in full force and effect so long as operations are prosecuted with reasonable diligence or are suspended under Paragraph 27 hereof; and, if such drilling or reworking operations result in the production of oil or gas, the lease shall remain in full force and effect so long as oil or gas is produced therefrom in paying quantities.

7. EXTENSION BY SHUT-IN PRODUCTION. If, upon the expiration of the primary term or at any time or times thereafter, there is on said land a well capable of producing oil or gas in paying quantities, this lease shall not expire because Lessee fails to produce the same unless Lessor gives notice to Lessee allowing a reasonable time, which shall not be less than sixty days, after such notice to place the well on a producing status, and Lessee fails to do so; provided, that after such status is established such prdouction shall continue on the said land unless and until suspension of production is allowed by Lessor.

8. EXTENSION BY SUSPENSION OF PRODUCTION. This lease shall not expire because of any suspension of operations in or upon or production from said land if such suspension is made under any order or with the consent of Lessor.

9. RENTAL. This lease shall termination on any anniversary date hereof prior to the completion on said land of a well capable of producing oil or gas in paying quantities, unless on or before said anniversary date Lessee shall pay or tender to Lessor as annual rental a sum equal to $1.00 per acre, or fraction thereof, then included in this lease, or unless such annual rental has been waived or suspended as provided in Paragraph 13 of this lease. If Lessor's office is not open for business on the anniversary date, the time for payment is extended to include the next day on which said office is open for business. Any rental paid for any one lease year shall be credited on any royalty for that year.

10. MINIMUM ROYALTY. Commencing with the lease year beginning on or after completion on said land of a well capable of producing oil or gas in paying quantities, Lessee shall pay Lessor, at the expiration of each lease year, in lieu of rental a minimum royalty equal to $1.00 per acre, or fraction thereof, then included in this lease, or the difference between the actual royalty paid on production during the year if less than $1.00 per acre and the prescribed minimum royalty.

11. ROYALTY ON PRODUCTION. Except for oil and gas used on said land for development and production or unavoidably lost, Lessee shall pay Lessor as royalty the following:

(a) On oil 12½ per cent in amount or value of the oil produced and saved and removed or sold from said land.

(b) On gas 12½ per cent in amount or value of the gas produced and saved and sold or used off said land or used for the extraction of natural gasoline or other products therefrom.

(c) On associated substances 12½ percent in amount or value of such substances produced and saved and removed or sold from said lands.

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discovery of oil or gas in commercial quantities in any geological structure, the royalty rate under this lease shall, instead of the rates prescribed in Paragraph 11, be five per cent for a period of ten years following the date of such discovery, and thereafter the royalty rates shall be those prescribed in Paragraph 11. If this lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, the five per cent royalty rate shall apply t all, but only, the production allocated to this lease under such agreement.

13. REDUCTION OF RENTAL AND ROYALTY. Rental or minimum royalty may be waived, suspended, or reduced, or royalty may be reduced on all of said land or any tract or portion thereof segregated for royalty purposes if Lessor finds that such relief is necessary for the purpose of encouraging the greatest ultimate recovery of oil or gas and is in the interest of conservation of natural resources and either that such relief is necessary in order to promote development or that the lease cannot be successfully operated under the terms provided herein.

14. ROYALTY IN KIND. Whenever, at the option of Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, Lessor elects to take its royalty in kind, Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon) to Lessor or to such individual, firm, or corporation as Lessor may designate all royalty oil and/or gas produced and saved from said land. Such oil and/or gas shall be in good and merchantable condition. Lessee shall, if necessary, furnish storage for royalty oil free of charge for thirty days after the end of the calendar month in which the oil is produced from said land; provided, that Lessee shall not be held liable for loss or destruction of royalty oil and/or gas from causes beyond Lessee's reasonable control. Should Lessee dehydrate or clean the oil or gas produced from said land, Lessee shall be entitled to an allowance of the actual cost of dehydrating or cleaning said royalty oil or gas.

15. ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts of gross production.

16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or, (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

17. PAYMENTS. All payments to Lessor under this lease shall be made payable to the Department of Revenue of the State of Alaska and shall be tendered to Lessor at the place designated under Paragraph 43 for giving notices to Lessor.

18. OFFSET WELLS. Lessee shall drill such wells as a reasonably prudent operator would drill to protect Lessor adequately from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas should be produced in a well on other land not owned by Lessor or on which Lessor receives a lower rate of royalty than the royalty under this lease, which well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and such well shall produce oil or gas in paying quantities for a period of thirty consecutive days, and if, after notice to Lessee and an opportunity to be heard, Lessor finds that production from such well is draining lands then subject ot this lease, Lessee shall within 120 days after written demand by Lessor begin in good faith and prosecute diligently drilling operations for an offset well on said land. In lieu of drilling any well required by this paragraph, Lessee may with Lessor's consent compensate Lessor in full each month for the estimated loss of royalty through drainage in the amount determined by lessor.

19. OTHER WELLS. This lease contemplates the reasonable development of said land for oil and gas as the facts may justify. Upon discovery of oil or gas in paying quantities on said land, Lessee shall drill such wells as a reasonably prudent operator would drill having due regard for the interests of Lessor as well as the interests of Lessee.

20. DILIGENCE; PREVENTION OF WASTE. Lessee shall exercise reasonable diligence in drilling, producing, and operating wells on said land unless consent to suspend operations temporarily is granted by Lessor; shall carry on all operations hereunder in a good and workmanlike manner in accordance with approved methods and practices, having due regard for the prevention of waste of oil and gas and the entrance of water to the oil and gas bearing sands or strata to the destruction or injury of such deposits and the preservation and conservation of the property for future productive operations; shall use reasonable care and all proper safeguards to prevent the pollution of water; shall plug securely in an approved manner any well before abandoningit; shall allow Lessor to inspect all operations at any time; shall carry out at Lessee's expense all reasonable orders and requirements of Lessor relative to the prevention of waste and the preservation of said land, and on failure of Lessee so to do, Lessor shall have the right together with any other recourse available to it to enter on said land to repair damage or prevent waste at Lessor's expense; and shall abide by and conform to valid applicable rules and regulations of the Alaska Oil and Gas Conservation Commission and the regulations of Lessor relating to the matters covered by this paragraph in effect on the effective date hereof or hereafter in effect if not inconsistent with any specific provisions of this lease.

21. WELL LOCATIONS. Lessee shall within five days after spudding in a well advise Lessor in writing of the location and date of spudding of said well.

22. APPROVAL OF PLANS. Lessee shall not place into actual operation any plan or method for the purpose of stimulating or increasing production on said land other than plans and methods in common use without first having obtained the written approval of Lessor.

23. LOGS AND RECORDS. An electric log or radioactive log, if taken, and a descriptive geologic sample log, if taken, and a record of all tests run for each well drilled on said land, together with a plat showing the exact location of each such well, shall be filed with Lessor within sixty days after such well has been completed or abandoned; provided, that such logs and records of an exploratory well, whether completed as a producer or abandoned as a dry hole, may be filed at any time within eighteen months after the completion or abandonment of such well. Any and all information filed by Lessee with Lessor in connection with this lease shall be available at all times for the confidential use of Lessor for the purpose of enforcing compliance with the terms, covenants, and conditions of this lease and the regulations of Lessor but shall not be open for inspection by any person other than officers or employees of Lessor and persons performing any function or work assigned to them by Lessor except upon the written consent of Lessee. Notwithstanding any other provision hereof, said information may be disclosed to any person where such disclosure is reasonably necesary for the administration of the functions, responsibilities, and duties vested by law in the Commissioner of the Department of Natural Resources or in the Division of Lands or the Director thereof, including but not limited to functions, responsibilities, and duties arising in connection with any litigation or administrative adjudication relating to this lease or to the rights, duties, and obligations arising hereunder.

24. RECORDS. Lessee shall keep and have in its possession books and records showing the production and disposition of all oil and gas produced from said land and shall permit Lessor or its agents at all reasonable hours to examine the same. Such records and reports of production shall be based upon such methods and techniques as shall insure the most accurate figures reasonably available without requiring the Lessee to provide separate tankage for each well.

25. DAMAGES. Section 2 of Article VII of the Alaska Land Act, Chapter 169, S.L.A., 1959, provides in part that no rights under reservations contained in certain leases or grants of Alaska land shall be exercised by Lessor or its Lessee until provision has been made to pay to the owner of the land upon which the reserved rights are sought to be exercised full payment for all damages sustained by said owner by reason of entering upon said land; provided, that if said owner for any cause whatever refuses or neglects to settle said damages, Lessor or its Lessee shall have the right to institute such legal proceedings in a court of competent jurisdiction wherein the land is situated as may be

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age that may become payable under said statutory provisions and to indemnify Lessor and hold it harmless from any against any claims, demands, liabilities and expenses arising from or in connection with such damage. The furnishing of a bond in compliance with this Le will be regarded by Lessor as a sufficient provision for the payment of all damage that may become payable under said statutory provisions.

26. BONDS.

(a) Lessee shall maintain the bond furnished prior to the issuance of this lease in an amount equal to at least $2.00 per acre or fraction thereof contained in said land but not less than $1,000.00.

(b) Before beginning drilling operations on said land Lessee must have furnished and shall maintain a bond in an amount of at least $5,000.00.

(c) Lessee may, in lieu of the foregoing, furnish and maintain a statewide bond in the amount of $100,000.00

(d) Lessor may, after notice to Lessee and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified above in this paragraph where such greater amount is justified by the nature of the surface and its uses and improvements in the vicinity of said land and the degree of the risks involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph but will be considered by Lessor in determining the need for and the amount of any additional bond under this subparagraph.

(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

27. ACTS OF GOD. Should Lessee be prevented from complying with any expressed or implied covenant of this lease, from conducting drilling operations thereon, or from producing or marketing oil or gas from said land after efforts made in good faith, by reason of war, riots, acts of God, severe weather in the area of said land, acts of governmental authorities, failure or lack of adequate transportation facilities, or any other cause beyond Lessee's reasonable control whether similar to those enumerated or not, then while so prevented and for a reasonable time thereafter within which to resume operations, Lessee's obligation to comply with such covenant shall be suspended and Lessee shall not be liable for damages for failure to comply therewith. If drilling or reworking operations are suspended by virtue of this paragraph and the prosecution of such operations would have had the effect of preventing the expiration or termination of this lease, then this lease shall not terminate during the period which the obligation to perform such operations is suspended under this paragraph; provided, however, that nothing in this paragraph shall be construed to suspend the payment of rentals or of minimum royalties.

28. SUSPENSION. Lessor may from time to time direct or assent to the suspension of production or other operations or both under this lease is such action is necessary or justified in the interest of conservation.

29. RESERVATIONS. Lessor reserves the right to dispose of the surface of said land to others subject to this lease, and the right to authorize others by grant, lease, or permit subject to this lease and under such conditions as will prevent unnecessary or unreasonable interference with the rights of Lessee and operations under this lease, to enter upon and use said land:

(a) To explore for oil or gas by geological or geophysical means including the drilling of shallow core holes or stratigraphic tests to a depth of not more than 1,000 feet.

(b) To explore for, develop and remove natural resources other than oil, gas, and associated substances on or from said land.

(c) For nonexclusive easements and rights of way for any lawful purpose including shafts and tunnels necessary or appropriate for the working of said land or other lands for natural resources other than oil, gas or associated substances.

(d) For well sites and well bores of wells drilled from or through said land to explore for or produce oil, gas, and associated substances in and from other lands.

(e) For any other purpose now or hereafter authorized by law and not inconsistent with the rights of Lessee under this lease.

30. UNDERGROUND STORAGE. This lease does not authorize the subsurface storage of oil or gas except as a necessary incident to recycling pressure maintenance, repressuring, or other similar operations designed to increase the ultimate recovery of oil or gas or prevent the waste of oil or gas produced from said land or from any unit area of which the said land is a part. Lessor reserves the right to authorize the subsurface storage of oil or gas in said land by Lessee or by others in order to avoid waste or to promote conservation of natural resources and upon such conditions as will prevent unnecessary or unreasonable interference with the rights and operations of Lessee under this lease, including conditions prohibiting the storage of oil or gas without the consent of Lessee in any reservoir covered by this lease capable of producing oil or gas in paying quantities.

31. ASSIGNMENTS. This lease or any undivided interest herein may with the approval of Lessor be assigned or subleased as to said land or any one or more legal subdivisions included therein, or any separate and distinct zone or geological horizon underlying said land or such one or more legal subdivisions, to any person or persons qualified to hold a lease. No transfer of any interest in this lease including assignments of working or royalty interests and operating agreements and subleases shall be binding upon Lessor unless approved by Lessor. Lessee shall remain liable for all obligations under this lease accruing prior to the approval of such transfer. Approval of transfer of this lease or an interest therein will not be denied except (1) for failure to comply with the regulations, (2) in the discretion of Lessor, where the transfer covers any distinct zone or geological horizon, or (3) where Lessor determines that the best interests of Lessor justify such action. Applications for approval of a transfer under this paragraph must comply with the regulations and must be filed within ninety days after the date of final execution of the instrument of transfer. Where a transfer is made of all or a part of Lessee's interest in and to a portion of the acreage in said land the assigned acreage shall, at the option of Lessor, or may upon request of the transferee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

32. UNITIZATION. Whenever determined and certified by Lessor to be necessary or advisable in the public interest for the purpose of properly conserving the natural resources of any oil or gas pool, field or like area or any part thereof, which includes or underlies said land or any part thereof, Lessee may unite with other Lessees of Lessor or with others owning or operating lands not belonging to Lessor including lands belonging to the United States and with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the development or operation of the pool or field or like area or part thereof. Lessee shall within thirty days after demand by Lessor subscribe to such a cooperative or unit agreement, which agreement shall be reasonable and shall adequately protect all parties in interest including Lessor. Lessor may with the consent of Lessee establish, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of this lease if committed to any such cooperative or unit agreement and may make such regulations with reference to this lease with the like consent of Lessee in connection with the institution and operation of any such cooperative or unit agreement as Lessor may determine to be necessary or proper to secure the proper protection of the public interest. If a portion of said land is committed to an approved or prescribed unit agreement, the committed acreage shall at the option of Lessor and may upon the request of Lessee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

3. SURRENDER. Lessee may at any time make and file with Lessor a written surrender of all rights under this lease or any portion thereof comprising one or more legal subdivisions or, with the consent of Lessor, of any separate and distinct Zone or geological horizon underlying said lands or such one or more legal subdivisions thereof. Such a surrender shall be effective as of the date of filing subject to the continued obligations of Lessee and his surety to make payment of all royalties theretofore accrued and to place all wells on the surrendered land or in the surrendered zones or horizons in condition satisfactory to Lessor for suspension or abandonment, thereupon, Lessee shall be released from all other obligations accrued or to accrue under this lease with respect to the surrendered lands, zones, or horizons.

than the payment of rental and Lessee fails within sixty days after written notice of such default to commence to remedy and thereafter prosecute diligently operations to remedy such default, Lessor may cancel this lease if at that time there is no well on said land capable of producing oil or gas in paying quantities. If at such time there is on said land a well capable of producing oil or gas in paying quantities, this lease may be cancelled only by judicial proceedings. In the event of any cancellation under this paragraph, Lessee shall have the right to retain under this lease any and all drilling or producing wells as to which no default exists together with a parcel of land surrounding each such well or wells and such rights of way through said land as may be reasonably necessary to enable Lessee to drill and operate such retained well or wells.

35. EXCESS AREA. If for any reason said land includes more acreage than the maximum permitted under aplicable laws and/or regulations, this lease shall not be void but the acreage included in said land shall be reduced to the permitted maximum. Whenever Lessor determines that this lease so exceeds the permitted acreage and notifies Lessee stating the amount of acreage that must be eliminated, Lessee may within sixty days after such notice surrender one or more legal subdivisions included in said lands comprising at least the amount of acreage that must be eliminated. If such a surrender is not filed within such sixty days Lessor may terminate this lease as to the acreage that must be eliminated by mailing notice of such termination to Lessee describing the parcel or parcels eliminated. Such a notice shall have the effect of terminating this lease as to the parcel or parcels described in such notice.

36. RIGHTS ON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion of said lands, Lessee shall have the privilege at any time within a period of six months thereafter, or such extension thereof as may be granted by Lessor, of removing from said land or portion thereof all machinery, equipment, tools, and materials other than improvements needed for producing wells. Any materials, tools, appliances, machinery, structures, and equipment subject to removal as above provided which are allowed to remain on said land or portion thereof shall become the property of Lessor upon expiration of such period; provided, that Lessee shall remove any and all of such properties when so directed by Lessor. Subject to the foregoing, Lessee shall deliver up said lands or such portion or portions thereof in good order and condition.

37. INTEREST IN LAND. It is the intention of the parties that the rights vested in Lessee by this lease shall constitute an interest in real property in said land.

38. LESSOR INTEREST. If Lessor owns a lesser interest in the oil and gas deposits in said land than the entire and undivided fee simple estate, then the royalties and rentals herein provided shall be paid Lessor only in the proportion which its interest bears to the whole and undivided fee.

39. CONDITIONAL LEASE. If all or a part of said land is land that has been selected by the Lessor under laws of the United States granting lands to Lessor, but such land has not been patented to Lessor by the United States, then this lease is a conditional lease as provided by law until such patent become effective. If for any reason such a selection is not finally approved or such a patent does not become effective, and rental, royalty or minimum royalty payments made to Lesosr under this lease will not be refunded.

40. DRILLING OPERATIONS. As used in this lease "drilling operations" mean any work or actual operations undertaken or commenced in good faith for the purpose of carrying out any of the rights, privileges or duties of Lessee under this lease, followed diligently and in due course by the construction of a road or derrick and/or other necessary structures for the drilling of an oil or gas well, and by the actual operation of drilling in the ground. Any such work or operations preliminary to drilling in the ground may be undertaken either on said land or in the vicinity of said land in any order Lessee shall see fit.

41. RULES AND REGULATIONS. As used in this lease "regulations" mean the applicable and valid oil and gas leasing regulations of the Commsisioner of the Department of Natural Resources in effect on the effective date of this lease unless otherwise specified.

42. INTERPRETATION. As used in this lease words which are defined in the regulations have the meaning assigned by such definition except where the context clearly requires a different meaning. The paragraph headings are not a part of this lease and are inserted only for convenience.

43. NOTICES. Any notice required or permitted under this lease shall be in writing and shall be given by registered or certified mail, return receipt requested, addressed as follows:

To Lessor:
Director, Division of Lands
State of Alaska
353 "D" Street
Anchorage, Alaska

To Lessee:
THE OHIO OIL COMPANY
550 South Flower St.,
Los Angeles 17, Calif.

Any such notice shall be deemed given when delivered to the foregoing address. Either party may change the address to which such notices are to be sent, by a notice given in accordance with this paragraph.

42. HEIRS AND ASSIGNS. Subject to the other provisions of this lease, the covenants, conditions, and agreements contained in this lease shall extend to and be binding upon the heirs, executors, administrators, successors, or assigns of Lessor and Lessee.

IN WITNESS WHEREOF the parties have executed this lease.

THE OHIO OIL COMPANY
by George Sowards
Division Manager
UNION OIL COMPANY OF CALIFORNIA
by [signature]
Attorney-in-Fact
LESSEE

STATE OF ALASKA
By [signature]
Director, Division of Lands
LESSOR

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THE UNITED STATES OF AMERICA)
) ss.
STATE OF ALASKA

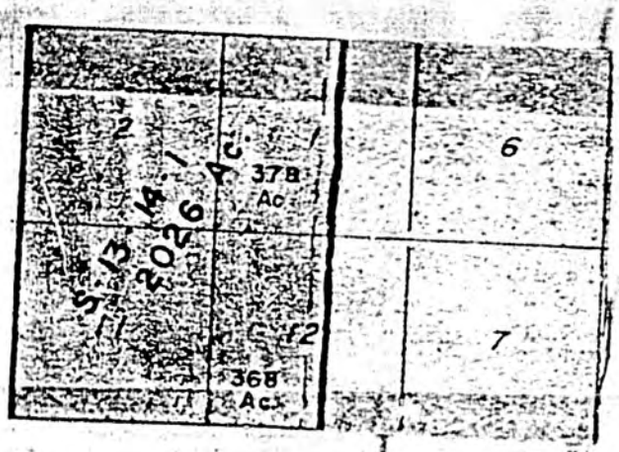
This certifies that on the 31st day of January, 1960 before me a notary public in and for the State of Alaska, duly commissioned and sworn, personally appeared ROSCOE E. BELL, to me known and known to me to be the person described in and who executed hte foregoing lease on behalf of the State of Alaska as Director of the Division of Lands, Department of Nautral Resources. The said ROSCOE E. BELL, executed said lease in my presence and, after being duly sworn according to law, stated to me under oath that he is the Director of the Division of Lands, Department of Natural Resources and has authority pursuant to law to execute the foregoing lease as such Director on behalf of the State of Alaska, acting through the Division of Lands, Department of Natural Resources and that he executed the same freely and voluntarily as the free and voluntary act, and lease of the said State of Alaska and for the Division of Lands, Department of Natural Resources.

WITNESS my hand and official seal the day and year in this certificate first above written.

[signature]
Notary Public in and for Alaska

My Commission expires 10-23-63

MAP OF TRACT AS INDICATED ON PROTRACTION
GRID OF THE COOK INLET SHELIKOF STRAIT SERIES



S-13-14-1

Fractional Sec. 1		378
Sec. 2 (All)		640
Sec. 11 (All)		640
Fractional Sec. 12		368
T. 4N R. 12W, S.M.	Total	2026

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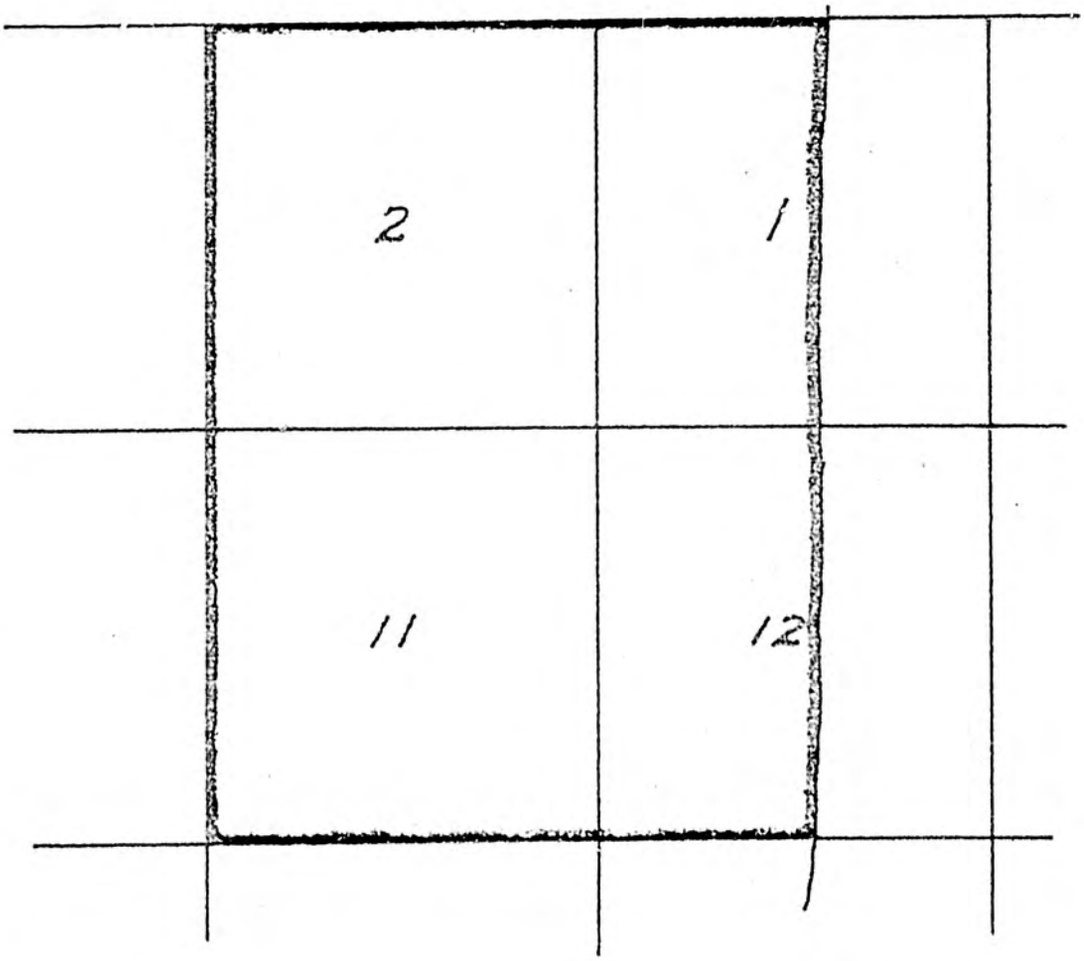
T. 4 N., R. 12 W., S.M.



Parcel S-13-14-1 2,026 ac.

FORM NO. DL-1

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

LEASE NO. ADL 00594

Competitive Oil and Gas Lease

THIS LEASE, dated the 1st day of January, 19 60, is made by and between the State of Alaska, acting by and through the Director of the Division of Lands of the Department of Natural Resources, hereinafter called "Lessor", and

THE OHIO OIL COMPANY, an Ohio corporation

UNION OIL COMPANY OF CALIFORNIA, a California corporation

hereinafter called "Lessee", whether one or more.

1. GRANT. For and in consideration of a cash bonus and the first year's rental, the receipt of which is hereby acknowledged, and of the rentals, royalties, covenants, and conditions herein contained on the part of the Lessee to be paid, kept and performed, and subject to the conditions and reservations herein contained, Lessor does hereby grant and lease unto Lessee, exclusively, without warranty, for the sole and only purposes of exploration, development, production, processing and marketing of oil, gas, and associated substances produced therewith, and of installing pipe lines and structures thereon to find, produce, save, store, treat, process, transport, take care of and market all such substances,

All that portion of projected sections 13 and 24 lying westerly of the coastline and all of projected sections 14 and 23, T.4N., R.12W., S.M., as per protraction sheet grid No. S-13-14 approved September 14, 1959, being designated also as parcel No. S-13-14-2.

under the public land rectangular system, and [illegible]
approved, subject, however, to the provisions of the regulations relating to such surveys.

2. "OIL AND GAS". "Oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced and saved in liquid form at the well by ordinary production methods. "Gas" means all natural gas and all hydrocarbons produced at the well not defined herein as oil. "Associated substances" means all substances produced in association with oil or gas and not defined herein as oil or gas.

3. TERM. This lease is issued for an initial primary term of five years from the date hereof, subject to extension as provided in Paragraph 4 hereof, and shall continue so long thereafter as oil and gas or either or any of them are produced in paying quantities from said land; provided, that this lease may be extended beyond its primary term as provided in Paragraph 5 hereof and shall not expire under the conditions set forth in Paragraphs 6, 7, and 8 hereof.

4. EXTENSION BY SUSPENSION OF OPERATIONS. If, prior to the expiration of the primary term, Lessor, in the interest of conservation, directs or assents to the suspension of all operations and production, if any, hereunder, the primary term will be extended by adding the period of suspension thereto.

5. EXTENSION BY UNIT PRODUCTION. This lease shall without application be extended beyond its primary term if upon or prior to the expiration date of such term the lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, production of oil or gas is had in paying quantities under the agreement. and a portion of such production is allocated to said land under the agreement. In such event this lease shall continue in effect so long as it remains subject to such agreement and actual production under said agreement is allocated to said land.

6. EXTENSION BY DRILLING. If production shall have been obtained in paying quantities during the primary term, and if, at the end of the primary term, or at any time prior to the end of the primary term, such production shall have ceased from any cause, or in the event production shall at any time or times after the expiration of the primary term cease from any cause, then this lease shall not terminate if the Lessee commences drilling or reworking operations (either in a well from which such production has ceased or in a new well) within sixty days after ther cessation of production, and the lease shall remain in full force and effect so long as operations are prosecuted with reasonable diligence or are suspended under Paragraph 27 hereof; and, if such drilling or reworking operations result in the production of oil or gas, the lease shall remain in full force and effect so long as oil or gas is produced therefrom in paying quantities.

7. EXTENSION BY SHUT-IN PRODUCTION. If, upon the expiration of the primary term or at any time or times thereafter, there is on said land a well capable of producing oil or gas in paying quantities, this lease shall not expire because Lessee fails to produce the same unless Lessor gives notice to Lessee allowing a reasonable time, which shall not be less than sixty days, after such notice to place the well on a producing status, and Lessee fails to do so; provided, that after such status is established such prdouction shall continue on the said land unless and until suspension of production is allowed by Lessor.

8. EXTENSION BY SUSPENSION OF PRODUCTION. This lease shall not expire because of any suspension of operations in or upon or production from said land if such suspension is made under any order or with the consent of Lessor.

9. RENTAL. This lease shall termination on any anniversary date hereof prior to the completion on said land of a well capable of producing oil or gas in paying quantities, unless on or before said anniversary date Lessee shall pay or tender to Lessor as annual rental a sum equal to $1.00 per acre, or fraction thereof, then included in this lease, or unless such annual rental has been waived or suspended as provided in Paragraph 13 of this lease. If Lessor's office is not open for business on the anniversary date, the time for payment is extended to include the next day on which said office is open for business. Any rental paid for any one lease year shall be credited on any royalty for that year.

10. MINIMUM ROYALTY. Commencing with the lease year beginning on or after completion on said land of a well capable of producing oil or gas in paying quantities, Lessee shall pay Lessor, at the expiration of each lease year, in lieu of rental a minimum royalty equal to $1.00 per acre, or fraction thereof, then included in this lesne, or the difference between the actual royalty paid on production during the year if less than $1.00 per acre and the prescribed minimum royalty.

11. ROYALTY ON PRODUCTION. Except for oil and gas used on said land for development and production or unavoidably lost, Lessee shall pay Lessor as royalty the following:

(a) On oil 12½ per cent in amount or value of the oil produced and saved and removed or sold from said land.

(b) On gas 12½ per cent in amount or value of the gas produced and saved and sold or used off said land or used for the extraction of natural gasoline or other products therefrom.

(c) On associated substances 12½ percent in amount or value of such substances produced and saved and removed or sold from said lands.

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12. REDUCTION OF ROYALTY RATES FOR DISCOVERY. If Lessee shall drill on said land and make the first discovery of oil or gas in commercial quantities in any geological structure, the royalty rate under this lease shall, instead of the rates prescribed in Paragraph 11, be five per cent for a period of ten years following the date of such discovery, and thereafter the royalty rates shall be those prescribed in Paragraph 11. If this lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, the five per cent royalty rate shall apply t all, but only, the production allocated to this lease under such agreement.

13. REDUCTION OF RENTAL AND ROYALTY. Rental or minimum royalty may be waived, suspended, or reduced, or royalty may be reduced on all of said land or any tract or portion thereof segregated for royalty purposes if Lessor finds that such relief is necessary for the purpose of encouraging the greatest ultimate recovery of oil or ga and is in the interest of conservation of natural resources and either that such relief is necessary in order to promot development or that the lease cannot be successfully operated under the terms provided herein.

14. ROYALTY IN KIND. Whenever, at the option of Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, Lessor elects to take its royalty in kind, Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon) to Lessor or to such individual, firm, or corporation as Lessor may designate all royalty oil and/or gas produced and saved from said land. Such oil and/or gas shall be in good and merchantable condition. Lessee shall, if necessary, furnish storage for royalty oil free of charge for thirty days after the end of the calendar month in which the oil is produced from said land; provided, that Lessee shall not be held liable for loss or destruction of royalty oil and/or gas from causes beyond Lessee's reasonable control. Should Lessee dehydrate or clean the oil or gas produced from said land, Lessee shall be entitled to an allowance of the actual cost of dehydrating or cleaning said royalty oil or gas.

15. ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts of gross production.

16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or, (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

17. PAYMENTS. All payments to Lessor under this lease shall be made payable to the Department of Revenue of the State of Alaska and shall be tendered to Lessor at the place designated under Paragraph 43 for giving notices to Lessor.

18. OFFSET WELLS. Lessee shall drill such wells as a reasonably prudent operator would drill to protect Lessor adequately from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas should be produced in a well on other land not owned by Lessor or on which Lessor receives a lower rate of royalty than the royalty under this lease, which well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and such well shall produce oil or gas in paying quantities for a period of thirty consecutive days, and if, after notice to Lessee and an opportunity to be heard, Lessor finds that production from such well is draining lands then subject ot this lease, Lessee shall within 120 days after written demand by Lessor begin in good faith and prosecute diligently drilling operations for an offset well on said land. In lieu of drilling any well required by this paragraph, Lessee may with Lessor's consent compensate Lessor in full each month for the estimated loss of royalty through drainage in the amount determined by lessor.

19. OTHER WELLS. This lease contemplates the reasonable development of said land for oil and gas as the fac may justify. Upon discovery of oil or gas in paying quantities on said land, Lessee shall drill such wells as a reasonably prudent operator would drill having due regard for the interests of Lessor as well as the interests of Lessee.

20. DILIGENCE; PREVENTION OF WASTE. Lessee shall exercise reasonable diligence in drilling, producing, and operating wells on said land unless consent to suspend operations temporarily is granted by Lessor; shall carry on all operations hereunder in a good and workmanlike manner in accordance with approved methods and practices, having due regard for the prevention of waste of oil and gas and the entrance of water to the oil and gas bearing sands or strata to the destruction or injury of such deposits and the preservation and conservation of the property for future productive operations; shall use reasonable care and all proper safeguards to prevent the pollution of water; shall plug securely in an approved manner any well before abandoningit; shall allow Lessor to inspect all operations at any time; shall carry out at Lessee's expense all reasonable orders and requirements of Lessor relative to the prevention of waste and the preservation of said land, and on failure of Lessee so to do, Lessor shall have the right together with any other recourse available to it to enter on said land to repair damage or prevent waste at Lessor's expense; and shall abide by and conform to valid applicable rules and regulations of the Alaska Oil and Gas Conservation Commission and the regulations of Lessor relating to the matters covered by this paragraph in effect on the effective date hereof or hereafter in effect if not inconsistent with any specific provisions of this lease.

21. WELL LOCATIONS. Lessee shall within five days after spudding in a well advise Lessor in writing of the location and date of spudding of said well.

22. APPROVAL OF PLANS. Lessee shall not place into actual operation any plan or method for the purpose of stimulating or increasing production on said land other than plans and methods in common use without first having obtained the written approval of Lessor.

23. LOGS AND RECORDS. An electric log or radioactive log, if taken, and a descriptive geologic sample log, if taken, and a record of all tests run for each well drilled on said land, together with a plat showing the exact location of each such well, shall be filed with Lessor within sixty days after such well has been completed or abandoned; provided, that such logs and records of an exploratory well, whether completed as a producer or abandoned as a dry hole, may be filed at any time within eighteen months after the completion or abandonment of such well. Any and all information filed by Lessee with Lessor in connection with this lease shall be available at all times for the confidential use of Lessor for the purpose of enforcing compliance with the terms, covenants, and conditions of this lease and the regulations of Lessor but shall not be open for inspection by any person other than officers or employees of Lessor and persons performing any function or work assigned to them by Lessor except upon the written consent of Lessee. Notwithstanding any other provision hereof, said information may be disclosed to any person where such disclosure is reasonably necesesary for the administration of the functions, responsibilities, and duties vested by law in the Commissioner of the Department of Natural Resources or in the Division of Lands or the Director thereof, including but not limited to functions, responsibilities, and duties arising in connection with any litigation or administrative adjudication relating to this lease or to the rights, duties, and obligations arising hereunder.

24. RECORDS. Lessee shall keep and have in its possession books and records showing the production and disposition of all oil and gas produced from said land and shall permit Lessor or its agents at all reasonable hours to examine the same. Such records and reports of production shall be based upon such methods and techniques as shall insure the most accurate figures reasonably available without requiring the Lessee to provide separate tankage for each well.

25. DAMAGES. Section 2 of Article VII of the Alaska Land Act, Chapter 169, S.L.A., 1959, provides in part that no rights under reservations contained in certain leases or grants of Alaska land shall be exercised by Lessor or its Lessee until provision has been made to pay to the owner of the land upon which the reserved rights are sought to be exercised full payment for all damages sustained by said owner by reason of entering upon said land; provided, that if said owner for any cause whatever refuses or neglects to settle said damages, Lessor or its Lessee shall have the

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age that may become payable under said statutory provisions and to indemnify Lessor and hold it harmless from and against any claims, demands, liabilities and expenses arising from or in connection with such damage. The furnishing of a bond in compliance with this [redacted] will be regarded by Lessor as a sufficient provision for the payment of all damage that may become payable under said statutory provisions.

26. BONDS:

(a) Lessee shall maintain the bond furnished prior to the issuance of this lease in an amount equal to at least $2.00 per acre or fraction thereof contained in said land but not less than $1,000.00.

(b) Before beginning drilling operations on said land Lessee must have furnished and shall maintain a bond in an amount of at least $5,000.00.

(c) Lessee may, in lieu of the foregoing, furnish and maintain a statewide bond in the amount of $100,000.00

(d) Lessor may, after notice to Lessee and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified above in this paragraph where such greater amount is justified by the nature of the surface and its uses and improvements in the vicinity of said land and the degree of the risks involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph but will be considered by Lessor in determining the need for and the amount of any additional bond under this subparagraph.

(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

27. ACTS OF GOD. Should Lessee be prevented from complying with any expressed or implied covenant of this lease, from conducting drilling operations thereon, or from producing or marketing oil or gas from said land after efforts made in good faith, by reason of war, riots, acts of God, severe weather in the area of said land, acts of governmental authorities, failure or lack of adequate transportation facilities, or any other cause beyond Lessee's reasonable control whether similar to those enumerated or not, then while so prevented and for a reasonable time thereafter within which to resume operations, Lessee's obligation to comply with such covenant shall be suspended and Lessee shall not be liable for damages for failure to comply therewith. If drilling or reworking operations are suspended by virtue of this paragraph and the prosecution of such operations would have had the effect of preventing the expiration or termination of this lease, then this lease shall not terminate during the period which the obligation to perform such operations is suspended under this paragraph; provided, however, that nothing in this paragraph shall be construed to suspend the payment of rentals or of minimum royalties.

28. SUSPENSION. Lessor may from time to time direct or assent to the suspension of production or other operations or both under this lease is such action is necessary or justified in the interest of conservation.

29. RESERVATIONS. Lessor reserves the right to dispose of the surface of said land to others subject to this lease, and the right to authorize others by grant, lease, or permit subject to this lease and under such conditions as will prevent unnecessary or unreasonable interference with the rights of Lessee and operations under this lease, to enter upon and use said land:

(a) To explore for oil or gas by geological or geophysical means including the drilling of shallow core holes or stratigraphic tests to a depth of not more than 1,000 feet.

(b) To explore for, develop and remove natural resources other than oil, gas, and associated substances on or from said land.

(c) For nonexclusive easements and rights of way for any lawful purpose including shafts and tunnels necessary or appropriate for the working of said land or other lands for natural resources other than oil, gas or associated substances.

(d) For well sites and well bores of wells drilled from or through said land to explore for or produce oil, gas, and associated substances in and from other lands.

(e) For any other purpose now or hereafter authorized by law and not inconsistent with the rights of Lessee under this lease.

30. UNDERGROUND STORAGE. This lease does not authorize the subsurface storage of oil or gas except as a necessary incident to recycling pressure maintenance, repressuring, or other similar operations designed to increase the ultimate recovery of oil or gas or prevent the waste of oil or gas produced from said land or from any unit area of which the said land is a part. Lessor reserves the right to authorize the subsurface storage of oil or gas in said land by Lessee or by others in order to avoid waste or to promote conservation of natural resources and upon such conditions as will prevent unnecessary or unreasonable interference with the rights and operations of Lessee under this lease, including conditions prohibiting the storage of oil or gas without the consent of Lessee in any reservoir covered by this lease capable of producing oil or gas in paying quantities.

31. ASSIGNMENTS. This lease or any undivided interest herein may with the approval of Lessor be assigned or subleased as to said land or any one or more legal subdivisions included therein, or any separate and distinct zone or geological horizon underlying said land or such one or more legal subdivisions, to any person or persons qualified to hold a lease. No transfer of any interest in this lease including assignments of working or royalty interests and operating agreements and subleases shall be binding upon Lessor unless approved by Lessor. Lessee shall remain liable for all obligations under this lease accruing prior to the approval of such transfer. Approval of transfer of this lease or an interest therein will not be denied except (1) for failure to comply with the regulations, (2) in the discretion of Lessor, where the transfer covers any distinct zone or geological horizon, or (3) where Lessor determines that the best interests of Lessor justify such action. Applications for approval of a transfer under this paragraph must comply with the regulations and must be filed within ninety days after the date of final execution of the instrument of transfer. Where a transfer is made of all or a part of Lessee's interest in and to a portion of the acreage in said land the assigned acreage shall, at the option of Lessor, or may upon request of the transferee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

32. UNITIZATION. Whenever determined and certified by Lessor to be necessary or advisable in the public interest for the purpose of properly conserving the natural resources of any oil or gas pool, field or like area or any part thereof, which includes or underlies said land or any part thereof, Lessee may unite with other Lessees of Lessor or with others owning or operating lands not belonging to Lessor including lands belonging to the United States and with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the development or operation of the pool or field or like area or part thereof. Lessee shall within thirty days after demand by Lessor subscribe to such a cooperative or unit agreement, which agreement shall be reasonable and shall adequately protect all parties in interest including Lessor. Lessor may with the consent of Lessee establish, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of this lease if committed to any such cooperative or unit agreement and may make such regulations with reference to this lease with the like consent of Lessee in connection with the institution and operation of any such cooperative or unit agreement as Lessor may determine to be necessary or proper to secure the proper protection of the public interest. If a portion of said land is committed to an approved or prescribed unit agreement, the committed acreage shall at the option of Lessor and may upon the request of Lessee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

3. SURRENDER. Lessee may at any time make and file with Lessor a written surrender of all rights under this lease or any portion thereof comprising one or more legal subdivisions or, with the consent of Lessor, of any separate and distinct Zone or geological horizon underlying said lands or such one or more legal subdivisions thereof. Such a surrender shall be effective as of the date of filing subject to the continued obligations of Lessee and his surety to make payment of all royalties theretofore accrued and to place all wells on the surrendered land or in the surrendered zones or horizons in condition satisfactory to Lessor for suspension or abandonment; thereupon, Lessee shall be released from all other obligations accrued or to accrue under this lease with respect to the surrendered lands, zones, or horizons.

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34. DEFAULT; TERMINATION. Whenever Lessee fails to comply with any of the provisions of this lease other than the payment of rental and Lessee fails within sixty days after written notice of such default to commence to remedy and thereafter prosecute diligently operations to remedy such default, Lessor may cancel this lease if at that time there is no well on said land capable of producing oil or gas in paying quantities. If at such time there is on said land a well capable of producing oil or gas in paying quantities, this lease may be cancelled only by judicial proceedings. In the event of any cancellation under this paragraph, Lessee shall have the right to retain under this lease any and all drilling or producing wells as to which no default exists together with a parcel of land surrounding each such well or wells and such rights of way through said land as may be reasonably necessary to enable Lessee to drill and operate such retained well or wells.

35. EXCESS AREA. If for any reason said land includes more acreage than the maximum permitted under applicable laws and/or regulations, this lease shall not be void but the acreage included in said land shall be reduced to the permitted maximum. Whenever Lessor determines that this lease so exceeds the permitted acreage and notifies Lessee stating the amount of acreage that must be eliminated, Lessee may within sixty days after such notice surrender one or more legal subdivisions included in said lands comprising at least the amount of acreage that must be eliminated. If such a surrender is not filed within such sixty days Lessor may terminate this lease as to the acreage that must be eliminated by mailing notice of such termination to Lessee describing the parcel or parcels eliminated. Such a notice shall have the effect of terminating this lease as to the parcel or parcels described in such notice.

36. RIGHTS ON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion of said lands, Lessee shall have the privilege at any time within a period of six months thereafter, or such extension thereof as may be granted by Lessor, of removing from said land or portion thereof all machinery, equipment, tools, and materials other than improvements needed for producing wells. Any materials, tools, appliances, machinery, structures, and equipment subject to removal as above provided which are allowed to remain on said land or portion thereof shall become the property of Lessor upon expiration of such period; provided, that Lessee shall remove any and all of such properties when so directed by Lessor. Subject to the foregoing, Lessee shall deliver up said lands or such portion or portions thereof in good order and condition.

37. INTEREST IN LAND. It is the intention of the parties that the rights vested in Lessee by this lease shall constitute an interest in real property in said land.

38. LESSOR INTEREST. If Lessor owns a lesser interest in the oil and gas deposits in said land than the entire and undivided fee simple estate, then the royalties and rentals herein provided shall be paid Lessor only in the proportion which its interest bears to the whole and undivided fee.

39. CONDITIONAL LEASE. If all or a part of said land is land that has been selected by the Lessor under laws of the United States granting lands to Lessor, but such land has not been patented to Lessor by the United States, then this lease is a conditional lease as provided by law until such patent become effective. If for any reason such a selection is not finally approved or such a patent does not become effective, and rental, royalty or minimum royalty payments made to Lesosr under this lease will not be refunded.

40. DRILLING OPERATIONS. As used in this lease "drilling operations" mean any work or actual operations undertaken or commenced in good faith for the purpose of carrying out any of the rights, privileges or duties of Lessee under this lease, followed diligently and in due course by the construction of a road or derrick and/or other necessary structures for the drilling of an oil or gas well, and by the actual operation of drilling in the ground. Any such work or operations preliminary to drilling in the ground may be undertaken either on said land or in the vicinity of said land in any order Lessee shall see fit.

41. RULES AND REGULATIONS. As used in this lease "regulations" mean the applicable and valid oil and gas leasing regulations of the Commsisioner of the Department of Natural Resources in effect on the effective date of this lease unless otherwise specified.

42. INTERPRETATION. As used in this lease words which are defined in the regulations have the meaning assigned by such definition except where the context clearly requires a different meaning. The paragraph headings are not a part of this lease and are inserted only for convenience.

43. NOTICES. Any notice required or permitted under this lease shall be in writing and shall be given by registered or certified mail, return receipt requested, addressed as follows:

To Lessor:

Director, Division of Lands
State of Alaska
333 "D" Street
Anchorage, Alaska

To Lessee:

THE OHIO OIL COMPANY
550 South Flower Street
Los Angeles 17, Calif.

Any such notice shall be deemed given when delivered to the foregoing address. Either party may change the address to which such notices are to be sent, by a notice given in accordance with this paragraph.

42. HEIRS AND ASSIGNS. Subject to the other provisions of this lease, the covenants, conditions, and agreements contained in this lease shall extend to and be binding upon the heirs, executors, administrators, successors, or assigns of Lessor and Lessee.

IN WITNESS WHEREOF the parties have executed this lease.

THE OHIO OIL COMPANY

by [signature]
Division Manager

UNION OIL COMPANY OF CALIFORNIA

by [signature]
Attorney-in-Fact

LESSEE

STATE OF ALASKA

By [signature]
Director, Division of Lands

LESSOR

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THE UNITED STATES OF AMERICA)
) ss.
STATE OF ALASKA)

This certifies that on the 5th day of November, 1960 before me a notary public in and for the State of Alaska, duly commissioned and sworn, personally appeared ROSCOE E. BELL, to me known and known to me to be the person described in and who executed hte foregoing lease on behalf of the State of Alaska as Director of the Division of Lands, Department of Nautral Resources. The said ROSCOE E. BELL, executed said lease in my presence and, after being duly sworn according to law, stated to me under oath that he is the Director of the Division of Lands, Department of Natural Resources and has authority pursuant to law to execute the foregoing lease as such Director on behalf of the State of Alaska, acting through the Division of Lands, Department of Natural Resources and that he executed the same freely and voluntarily as the free and voluntary act, and lease of the said State of Alaska and for the Division of Lands, Department of Natural Resources.

WITNESS my hand and official seal the day and year in this certificate first above written.

[signature]
Notary Public in and for Alaska

My Commission expires 10-23-63

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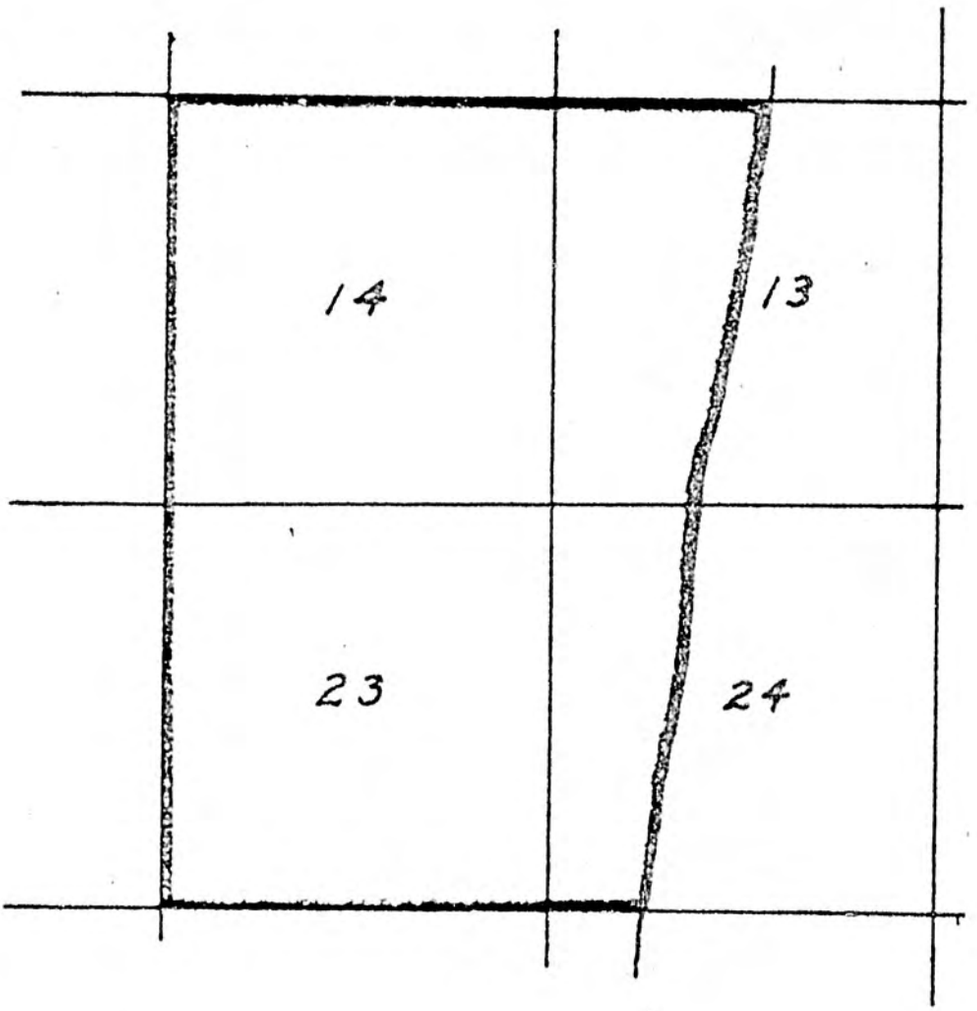
T. 4 N., R. 12 W., S.M.



Parcel S-13-14-2 1,797 ac.

AGI 570658

FORM NO. DL-1

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

02411

LEASE NO. ADL_____

Competitive Oil and Gas Lease

THIS LEASE, dated the 1st day of March, 1961, is made by and between the State of Alaska, acting by and through the Director of the Division of Lands of the Department of Natural Resources, hereinafter called "Lessor", and

UNION OIL COMPANY OF CALIFORNIA, a California corporation and

THE OHIO OIL COMPANY, an Ohio corporation

hereinafter called "Lessee", whether one or more.

1. GRANT. For and in consideration of a cash bonus and the first year's rental, the receipt of which is hereby acknowledged, and of the rentals, royalties, covenants, and conditions herein contained on the part of the Lessee to be paid, kept and performed, and subject to the conditions and reservations herein contained, Lessor does hereby grant and lease unto Lessee, exclusively, without warranty, for the sole and only purposes of exploration, development, production, processing and marketing of oil, gas, and associated substances produced therewith, and of installing pipe lines and structures thereon to find, produce, save, store, treat, process, transport, take care of and market all such substances, and for drilling water wells and taking underground and surface water for use in its operations thereon, and for housing and boarding employees in its operation thereon, the following described tract of land in Alaska:

All tide and submerged land in fractional Sections 18 and 19, T. 5N., R. 11W., S. M. and projected Secs. 13 and 24, T.5N., R.12W.,S.M. being designated Parcel S-13-11-2 containing 1,851.7 acres, more or less, hereinafter called "said land".

For the purposes of this lease, said land contains four (4) legal subdivisions, as shown on the plat of said land attached hereto, marked Exhibit A and by this reference made a part of this lease.

If said land is described above by protracted legal subdivisions, and Lessor hereafter causes said land to be surveyed under the public land rectangular system, the boundaries of said land shall be those established by such survey, when approved, subject, however, to the provisions of the regulations relating to such surveys.

2. "OIL AND GAS". "Oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced and saved in liquid form at the well by ordinary production methods. "Gas" means all natural gas and all hydrocarbons produced at the well not defined herein as oil. "Associated substances" means all substances produced in association with oil or gas and not defined herein as oil or gas.

3. TERM. This lease is issued for an initial primary term of five years from the date hereof, subject to extension as provided in Paragraph 4 hereof, and shall continue so long thereafter as oil and gas or either or any of them are produced in paying quantities from said land; provided, that this lease may be extended beyond its primary term as provided in Paragraph 5 hereof and shall not expire under the conditions set forth in Paragraphs 6, 7, and 8 hereof.

4. EXTENSION BY SUSPENSION OF OPERATIONS. If, prior to the expiration of the primary term, Lessor, in the interest of conservation, directs or assents to the suspension of all operations and production, if any, hereunder, the primary term will be extended by adding the period of suspension thereto.

5. EXTENSION BY UNIT PRODUCTION. This lease shall without application be extended beyond its primary term if upon or prior to the expiration date of such term the lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, production of oil or gas is had in paying quantities under the agreement. and a portion of such production is allocated to said land under the agreement. In such event this lease shall continue in effect so long as it remains subject to such agreement and actual production under said agreement is allocated to said land.

6. EXTENSION BY DRILLING. If production shall have been obtained in paying quantities during the primary term, and if, at the end of the primary term, or at any time prior to the end of the primary term, such production shall have ceased from any cause, or in the event production shall at any time or times after the expiration of the primary term cease from any cause, then this lease shall not terminate if the Lessee commences drilling or reworking operations (either in a well from which such production has ceased or in a new well) within sixty days after ther cessation of production, and the lease shall remain in full force and effect so long as operations are prosecuted with reasonable diligence or are suspended under Paragraph 27 hereof; and, if such drilling or reworking operations result in the production of oil or gas, the lease shall remain in full force and effect so long as oil or gas is produced therefrom in paying quantities.

7. EXTENSION BY SHUT-IN PRODUCTION. If, upon the expiration of the primary term or at any time or times thereafter, there is on said land a well capable of producing oil or gas in paying quantities, this lease shall not expire because Lessee falls to produce the same unless Lessor gives notice to Lessee allowing a reasonable time, which shall not be less than sixty days, after such notice to place the well in a producing status, and Lessee fails to do so; provided, that after such status is established such prdouction shall continue on the said land unless and until suspension of production is allowed by Lessor.

8. EXTENSION BY SUSPENSION OF PRODUCTION. This lease shall not expire because of any suspension of operations in or upon or production from said land if such suspension is made under any order or with the consent of Lessor.

9. RENTAL. This lease shall termination on any anniversary date hereof prior to the completion on said land of a well capable of producing oil or gas in paying quantities, unless on or before said anniversary date Lessee shall pay or tender to Lessor as annual rental a sum equal to $1.00 per acre, or fraction thereof, then included in this lease, or unless such annual rental has been waived or suspended as provided in Paragraph 13 of this lease. If Lessor's office is not open for business on the anniversary date, the time for payment is extended to include the next day on which said office is open for business. Any rental paid for any one lease year shall be credited on any royalty for that year.

10. MINIMUM ROYALTY. Commencing with the lease year beginning on or after completion on said land of a well capable of producing oil or gas in paying quantities, Lessee shall pay Lessor, at the expiration of each lease year, in lieu of rental a minimum royalty equal to $1.00 per acre, or fraction thereof, then included in this lease, or the difference between the actual royalty paid on production during the year if less than $1.00 per acre and the prescribed minimum royalty.

11. ROYALTY ON PRODUCTION. Except for oil and gas used on said land for development and production or unavoidably lost, Lessee shall pay Lessor as royalty the following:

(a) On oil 12½ per cent in amount or value of the oil produced and saved and removed or sold from said land.

(b) On gas 12½ per cent in amount or value of the gas produced and saved and sold or used off said land or used for the extraction of natural gasoline or other products therefrom.

(c) On associated substances 12½ percent in amount or value of such substances produced and saved and removed or sold from said lands.

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discovery of oil or gas in commercial quantities in any geological structure, the royalty rate under this lease shall, instead of the rates prescribed in Paragraph 11, be five per cent for a period of ten years following the date of such discovery, and thereafter the royalty rates shall be those prescribed in Paragraph 11. If this lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, the five per cent royalty rate shall apply t all, but only, the production allocated to this lease under such agreement.

13. REDUCTION OF RENTAL AND ROYALTY. Rental or minimum royalty may be waived, suspended, or reduced, or royalty may be reduced on all of said land or any tract or portion thereof segregated for royalty purposes if Lessor finds that such relief is necessary for the purpose of encouraging the greatest ultimate recovery of oil or gas and is in the interest of conservation of natural resources and either that such relief is necessary in order to promote development or that the lease cannot be successfully operated under the terms provided herein.

14. ROYALTY IN KIND. Whenever, at the option of Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, Lessor elects to take its royalty in kind, Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon) to Lessor or to such individual, firm, or corporation as Lessor may designate all royalty oil and/or gas produced and saved from said land. Such oil and/or gas shall be in good and merchantable condition. Lessee shall, if necessary, furnish storage for royalty oil free of charge for thirty days after the end of the calendar month in which the oil is produced from said land; provided, that Lessee shall not be held liable for loss or destruction of royalty oil and/or gas from causes beyond Lessee's reasonable control. Should Lessee dehydrate or clean the oil or gas produced from said land, Lessee shall be entitled to an allowance of the actual cost of dehydrating or cleaning said royalty oil or gas.

15. ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts of gross production.

16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or, (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

17. PAYMENTS. All payments to Lessor under this lease shall be made payable to the Department of Revenue of the State of Alaska and shall be tendered to Lessor at the place designated under Paragraph 43 for giving notices to Lessor.

18. OFFSET WELLS. Lessee shall drill such wells as a reasonably prudent operator would drill to protect Lessor adequately from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas should be produced in a well on other land not owned by Lessor or on which Lessor receives a lower rate of royalty than the royalty under this lease, which well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and such well shall produce oil or gas in paying quantities for a period of thirty consecutive days, and if, after notice to Lessee and an opportunity to be heard, Lessor finds that production from such well is draining lands then subject ot this lease, Lessee shall within 120 days after written demand by Lessor begin in good faith and prosecute diligently drilling operations for an offset well on said land. In lieu of drilling any well required by this paragraph, Lessee may with Lessor's consent compensate Lessor in full each month for the estimated loss of royalty through drainage in the amount determined by lessor.

19. OTHER WELLS. This lease contemplates the reasonable development of said land for oil and gas as the facts may justify. Upon discovery of oil or gas in paying quantities on said land, Lessee shall drill such wells as a reasonably prudent operator would drill having due regard for the interests of Lessor as well as the interests of Lessee.

20. DILIGENCE; PREVENTION OF WASTE. Lessee shall exercise reasonable diligence in drilling, producing, and operating wells on said land unless consent to suspend operations temporarily is granted by Lessor; shall carry on all operations hereunder in a good and workmanlike manner in accordance with approved methods and practices, having due regard for the prevention of waste of oil and gas and the entrance of water to the oil and gas bearing sands or strata to the destruction or injury of such deposits and the preservation and conservation of the property for future productive operations; shall use reasonable care and all proper safeguards to prevent the pollution of water; shall plug securely in an approved manner any well before abandoningit; shall allow Lessor to inspect all operations at any time; shall carry out at Lessee's expense all reasonable orders and requirements of Lessor relative to the prevention of waste and the preservation of said land, and on failure of Lessee so to do, Lessor shall have the right together with any other recourse available to it to enter on said land to repair damage or prevent waste at Lessor's expense; and shall abide by and conform to valid applicable rules and regulations of the Alaska Oil and Gas Conservation Commission and the regulations of Lessor relating to the matters covered by this paragraph in effect on the effective date hereof or hereafter in effect if not inconsistent with any specific provisions of this lease.

21. WELL LOCATIONS. Lessee shall within five days after spudding in a well advise Lessor in writing of the location and date of spudding of said well.

22. APPROVAL OF PLANS. Lessee shall not place into actual operation any plan or method for the purpose of stimulating or increasing production on said land other than plans and methods in common use without first having obtained the written approval of Lessor.

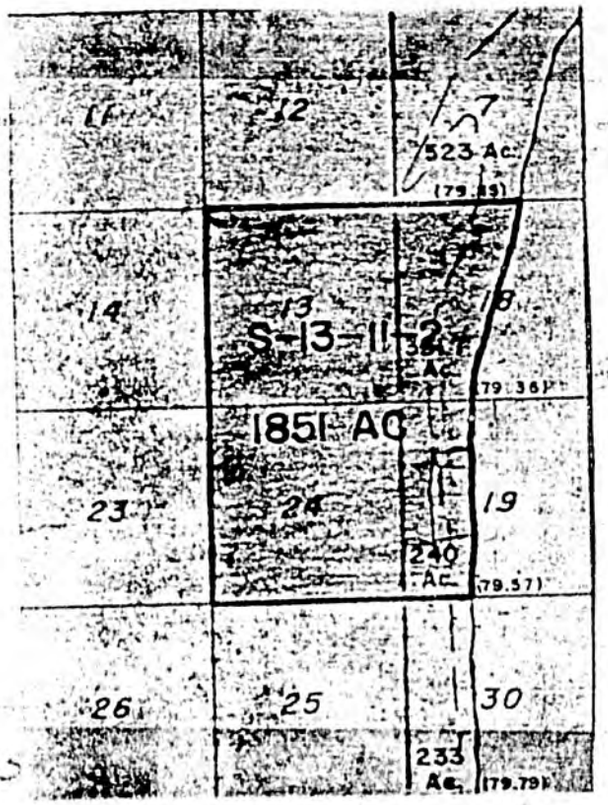
23. LOGS AND RECORDS. An electric log or radioactive log, if taken, and a descriptive geologic sample log, if taken, and a record of all tests run for each well drilled on said land, together with a plat showing the exact location of each such well, shall be filed with Lessor within sixty days after such well has been completed or abandoned; provided, that such logs and records of an exploratory well, whether completed as a producer or abandoned as a dry hole, may be filed at any time within eighteen months after the completion or abandonment of such well. Any and all information filed by Lessee with Lessor in connection with this lease shall be available at all times for the confidential use of Lessor for the purpose of enforcing compliance with the terms, covenants, and conditions of this lease and the regulations of Lessor but shall not be open for inspection by any person other than officers or employees of Lessor and persons performing any function or work assigned to them by Lessor except upon the written consent of Lessee. Notwithstanding any other provision hereof, said information may be disclosed to any person where such disclosure is reasonably necesesary for the administration of the functions, responsibilities, and duties vested by law in the Commissioner of the Department of Natural Resources or in the Division of Lands or the Director thereof, including but not limited to functions, responsibilities, and duties arising in connection with any litigation or administrative adjudication relating to this lease or to the rights, duties, and obligations arising hereunder.

24. RECORDS. Lessee shall keep and have in its possession books and records showing the production and disposition of all oil and gas produced from said land and shall permit Lessor or its agents at all reasonable hours to examine the same. Such records and reports of production shall be based upon such methods and techniques as shall insure the most accurate figures reasonably available without requiring the Lessee to provide separate tankage for each well.

25. DAMAGES. Section 2 of Article VII of the Alaska Land Act, Chapter 169, S.L.A., 1959, provides in part that no rights under reservations contained in certain leases or grants of Alaska land shall be exercised by Lessor or its Lessee until provision has been made to pay to the owner of the land upon which the reserved rights are sought to be exercised full payment for all damages sustained by said owner by reason of entering upon said land; provided, that if said owner for any cause whatever refuses or neglects to settle said damages, Lessor or its Lessee shall have the right to institute such legal proceedings in a court of competent jurisdiction wherein the land is situated as may be

AGO 570660

MAP OF TRACT AS INDICATED ON PROTRACTION
GRID OF THE COOK INLET SHELIKOF STRAIT SERIES



24

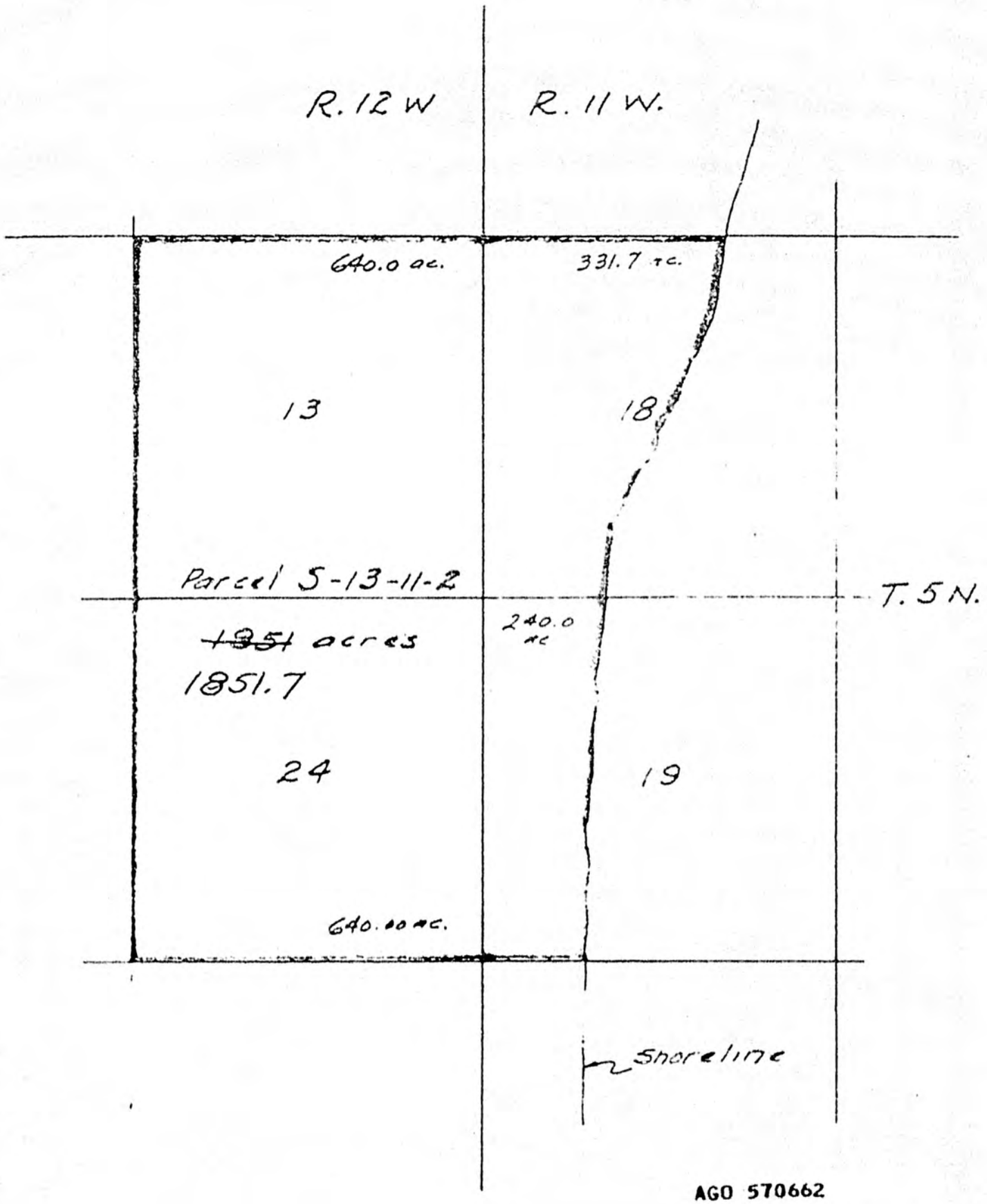
S-13-11-2 Frac. Section 18, T. 5N, R.11W., SM 331.7
Frac. Section 19, T. 5N, R.11W., SM 240.
All Section 13, T. 5N, R.12W., SM 640.
All Section 24, T. 5N, R.12W., SM 640.
~~1851.7~~ acres

640.00 ac.

1851.75 See dic. of 10/16/62
PJ

AGO 570661

...which the owner of such land may suffer. I accept hereby agrees to pay any dam-



AGO 570662

it may become payable under said statutory provisions and to indemnify Lessor and hold it harmless from and st any claims, demands, liabilities, and expenses arising from or in connection with such damage. The furnishing a bond in compliance with t[illegible]ease will be regarded by Lessor as a [illegible]ient provision for the payment of all damage that may become paya[illegible]nder said statutory provisions.

26. BONDS.

(a) Lessee shall maintain the bond furnished prior to the issuance of this lease in an amount equal to at least $2.00 per acre or fraction thereof contained in said land but not less than $1,000.00.

(b) Before beginning drilling operations on said land Lessee must have furnished and shall maintain a bond in an amount of at least $5,000.00.

(c) Lessee may, in lieu of the foregoing, furnish and maintain a statewide bond in the amount of $100,000.00

(d) Lessor may, after notice to Lessee and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified above in this paragraph where such greater amount is justified by the nature of the surface and its uses and improvements in the vicinity of said land and the degree of the risks involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph but will be considered by Lessor in determining the need for and the amount of any additional bond under this subparagraph.

(e) If said land is committed in whole or in part to a cooperative or unit agreement approved or prescribed by Lessor pursuant to law and the regulations and a unit bond is furnished in accordance with the regulations, Lessee need not thereafter maintain any bond with respect to the portion of said land so committed to such agreement.

27. ACTS OF GOD. Should Lessee be prevented from complying with any expressed or implied covenant of this lease, from conducting drilling operations thereon, or from producing or marketing oil or gas from said land after efforts made in good faith, by reason of war, riots, acts of God, severe weather in the area of said land, acts of governmental authorities, failure or lack of adequate transportation facilities, or any other cause beyond Lessee's reasonable control whether similar to those enumerated or not, then while so prevented and for a reasonable time thereafter within which to resume operations, Lessee's obligation to comply with such covenant shall be suspended and Lessee shall not be liable for damages for failure to comply therewith. If drilling or reworking operations are suspended by virtue of this paragraph and the prosecution of such operations would have had the effect of preventing the expiration or termination of this lease, then this lease shall not terminate during the period which the obligation to perform such operations is suspended under this paragraph; provided, however, that nothing in this paragraph shall be construed to suspend the payment of rentals or of minimum royalties.

28. SUSPENSION. Lessor may from time to time direct or assent to the suspension of production or other operations or both under this lease is such action is necessary or justified in the interest of conservation.

29. RESERVATIONS. Lessor reserves the right to dispose of the surface of said land to others subject to this lease, and the right to authorize others by grant, lease, or permit subject to this lease and under such conditions as will prevent unnecessary or unreasonable interference with the rights of Lessee and operations under this lease, to enter upon and use said land:

(a) To explore for oil or gas by geological or geophysical means including the drilling of shallow core holes or stratigraphic tests to a depth of not more than 1,000 feet.

(b) To explore for, develop and remove natural resources other than oil, gas, and associated substances on or from said land.

(c) For nonexclusive easements and rights of way for any lawful purpose including shafts and tunnels necessary or appropriate for the working of said land or other lands for natural resources other than oil, gas or associated substances.

(d) For well sites and well bores of wells drilled from or through said land to explore for or produce oil, gas, and associated substances in and from other lands.

(e) For any other purpose now or hereafter authorized by law and not inconsistent with the rights of Lessee under this lease.

30. UNDERGROUND STORAGE. This lease does not authorize the subsurface storage of oil or gas except as a necessary incident to recycling pressure maintenance, repressuring, or other similar operations designed to increase the ultimate recovery of oil or gas or prevent the waste of oil or gas produced from said land or from any unit area of which the said land is a part. Lessor reserves the right to authorize the subsurface storage of oil or gas in said land by Lessee or by others in order to avoid waste or to promote conservation of natural resources and upon such conditions as will prevent unnecessary or unreasonable interference with the rights and operations of Lessee under this lease, including conditions prohibiting the storage of oil or gas without the consent of Lessee in any reservoir covered by this lease capable of producing oil or gas in paying quantities.

31. ASSIGNMENTS. This lease or any undivided interest herein may with the approval of Lessor be assigned or subleased as to said land or any one or more legal subdivisions included therein, or any separate and distinct zone or geological horizon underlying said land or such one or more legal subdivisions, to any person or persons qualified to hold a lease. No transfer of any interest in this lease including assignments of working or royalty interests and operating agreements and subleases shall be binding upon Lessor unless approved by Lessor. Lessee shall remain liable for all obligations under this lease accruing prior to the approval of such transfer. Approval of transfer of this lease or an interest therein will not be denied except (1) for failure to comply with the regulations, (2) in the discretion of Lessor, where the transfer covers any distinct zone or geological horizon, or (3) where Lessor determines that the best interests of Lessor justify such action. Applications for approval of a transfer under this paragraph must comply with the regulations and must be filed within ninety days after the date of final execution of the instrument of transfer. Where a transfer is made of all or a part of Lessee's interest in and to a portion of the acreage in said land the assigned acreage shall, at the option of Lessor, or may upon request of the transferee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

32. UNITIZATION. Whenever determined and certified by Lessor to be necessary or advisable in the public interest for the purpose of properly conserving the natural resources of any oil or gas pool, field or like area or any part thereof, which includes or underlies said land or any part thereof, Lessee may unite with other Lessees of Lessor or with others owning or operating lands not belonging to Lessor including lands belonging to the United States and with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the development or operation of the pool or field or like area or part thereof. Lessee shall within thirty days after demand by Lessor subscribe to such a cooperative or unit agreement, which agreement shall be reasonable and shall adequately protect all parties in interest including Lessor. Lessor may with the consent of Lessee establish, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of this lease if committed to any such cooperative or unit agreement and may make such regulations with reference to this lease with the like consent of Lessee in connection with the institution and operation of any such cooperative or unit agreement as Lessor may determine to be necessary or proper to secure the proper protection of the public interest. If a portion of said land is committed to an approved or prescribed unit agreement, the committed acreage shall at the option of Lessor and may upon the request of Lessee and with the approval of Lessor be segregated into a separate and distinct lease having the same effective date as this lease.

33. SURRENDER. Lessee may at any time make and file with Lessor a written surrender of all rights under this lease or any portion thereof comprising one or more legal subdivisions or, with the consent of Lessor, of any separate and distinct Zone or geological horizon underlying said lands or such one or more legal subdivisions thereof. Such a surrender shall be effective as of the date of filing subject to the continued obligations of Lessee and his surety to make payment of all royalties theretofore accrued and to place all wells on the surrendered land or in the surrendered zones or horizons in condition satisfactory to Lessor for suspension or abandonment; thereupon, Lessee shall be released from all other obligations accrued or to accrue under this lease with respect to the surrendered lands, zones, or horizons.

34. DEFAULT; TERMINATION. Whenever Lessee fails to comply with any of the provisions of this lease other than the payment of rental and Lessee fails within sixty days after written notice of such default to commence to remedy and thereafter prosecute diligently operations to remedy such default, Lessor may cancel this lease if at that time there is no well on said land capable of producing oil or gas in paying quantities. If at such time there is on said land a well capable of producing oil or gas in paying quantities, this lease may be cancelled only by judicial proceedings. In the event of any cancellation under this paragraph, Lessee shall have the right to retain under this lease any and all drilling or producing wells as to which no default exists together with a parcel of land surrounding each such well or wells and such rights of way through said land as may be reasonably necessary to enable Lessee to drill and operate such retained well or wells.

35. EXCESS AREA. If for any reason said land includes more acreage than the maximum permitted under aplicable laws and/or regulations, this lease shall not be void but the acreage included in said land shall be reduced to the permitted maximum. Whenever Lessor determines that this lease so exceeds the permitted acreage and notifies Lessee stating the amount of acreage that must be eliminated, Lessee may within sixty days after such notice surrender one or more legal subdivisions included in said lands comprising at least the amount of acreage that must be eliminated. If such a surrender is not filed within such sixty days Lessor may terminate this lease as to the acreage that must be eliminated by mailing notice of such termination to Lessee describing the parcel or parcels eliminated. Such a notice shall have the effect of terminating this lease as to the parcel or parcels described in such notice.

36. RIGHTS ON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion of said lands, Lessee shall have the privilege at any time within a period of six months thereafter, or such extension thereof as may be granted by Lessor, of removing from said land or portion thereof all machinery, equipment, tools, and materials other than improvements needed for producing wells. Any materials, tools, appliances, machinery, structures, and equipment subject to removal as above provided which are allowed to remain on said land or portion thereof shall become the property of Lessor upon expiration of such period; provided, that Lessee shall remove any and all of such properties when so directed by Lessor. Subject to the foregoing, Lessee shall deliver up said lands or such portion or portions thereof in good order and condition.

37. INTEREST IN LAND. It is the intention of the parties that the rights vested in Lessee by this lease shall constitute an interest in real property in said land.

38. LESSOR INTEREST. If Lessor owns a lesser interest in the oil and gas deposits in said land than the entire and undivided fee simple estate, then the royalties and rentals herein provided shall be paid Lessor only in the proportion which its interest bears to the whole and undivided fee.

39. CONDITIONAL LEASE. If all or a part of said land is land that has been selected by the Lessor under laws of the United States granting lands to Lessor, but such land has not been patented to Lessor by the United States, then this lease is a conditional lease as provided by law until such patent become effective. If for any reason such a selection is not finally approved or such a patent does not become effective, and rental, royalty or minimum royalty payments made to Lesosr under this lease will not be refunded.

40. DRILLING OPERATIONS. As used in this lease "drilling operations" mean any work or actual operations undertaken or commenced in good faith for the purpose of carrying out any of the rights, privileges or duties of Lessee under this lease, followed diligently and in due course by the construction of a road or derrick and/or other necessary structures for the drilling of an oil or gas well, and by the actual operation of drilling in the ground. Any such work or operations preliminary to drilling in the ground may be undertaken either on said land or in the vicinity of said land in any order Lessee shall see fit.

41. RULES AND REGULATIONS. As used in this lease "regulations" mean the applicable and valid oil and gas leasing regulations of the Commsisioner of the Department of Natural Resources in effect on the effective date of this lease unless otherwise specified.

42. INTERPRETATION. As used in this lease words which are defined in the regulations have the meaning assigned by such definition except where the context clearly requires a different meaning. The paragraph headings are not a part of this lease and are inserted only for convenience.

43. NOTICES. Any notice required or permitted under this lease shall be in writing and shall be given by registered or certified mail, return receipt requested, addressed as follows:

To Lessor:
Director, Division of Lands
State of Alaska
333 "D" Street
Anchorage, Alaska

To Lessee:
Union Oil Co. of Calif.
2805 Denali Street
Anchorage, Alaska

Any such notice shall be deemed given when delivered to the foregoing address. Either party may change the address to which such notices are to be sent, by a notice given in accordance with this paragraph.

42. HEIRS AND ASSIGNS. Subject to the other provisions of this lease, the covenants, conditions, and agreements contained in this lease shall extend to and be binding upon the heirs, executors, administrators, successors, or assigns of Lessor and Lessee.

IN WITNESS WHEREOF the parties have executed this lease.

UNION OIL COMPANY OF CALIFORNIA
By [signature]
Attorney-in-Fact

THE OHIO OIL COMPANY
By [signature]
Division Manager LESSEE

STATE OF ALASKA
By [signature]
Director, Division of Lands
LESSOR

AGO 570664

THE UNITED STATES OF AMERICA)
) ss.
STATE OF ALASKA)

This certifies that on the 2nd day of February, 1961 before me a notary public in and for the State of Alaska, duly commissioned and sworn, personally appeared ROSCOE E. BELL, to me known and known to me to be the person described in and who executed hte foregoing lease on behalf of the State of Alaska as Director of the Division of Lands, Department of Nautral Resources. The said ROSCOE E. BELL, executed said lease in my presence and, after being duly sworn according to law, stated to me under oath that he is the Director of the Division of Lands, Department of Natural Resources and has authority pursuant to law to execute the foregoing lease as such Director on behalf of the State of Alaska, acting through the Division of Lands, Department of Natural Resources and that he executed the same freely and voluntarily as the free and voluntary act, and lease of the said State of Alaska and for the Division of Lands, Department of Natural Resources.

WITNESS my hand and official seal the day and year in this certificate first above written.

[signature]
Notary Public [illegible]d for Alaska

My Commission expires 12/25/64

LEASES (PHILLIPS)

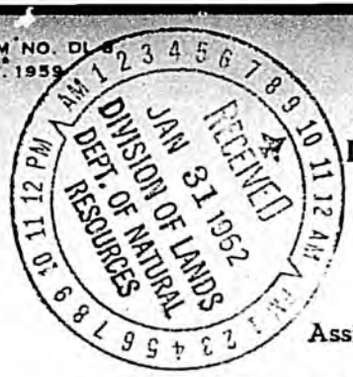
ASSIGNMENT OF LEASES TO PHILLIPS PETROLEUM

FROM PAN AMERICAN PETROLEUM AND ATLANTIC RICHFIELD

NORTH COOK INLET GAS FIELD

AGO 570666

FORM NO. DL-6
SEPT. 1959



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

LEASE NO. ADL 17589

Assignment Affecting Record Title to Oil and Gas Lease

The undersigned assignor, as owner of the record title interest specified in item 3 below in the oil and gas lease designated above, for a good and valuable consideration, does hereby assign to PHILLIPS PETROLEUM COMPANY whose address is BARTLESVILLE, OKLAHOMA the right, title and interest specified in item 4 below in and to the lands embraced in said lease described in item 1 below, or such portion thereof as the lessor may approve and described in item 2 below, giving and granting to assignee the rights and privileges of a lessee in said lands, to the extent indicated, subject to the reservations of overriding royalties noted in item 5 below:

1. LANDS REQUESTED

Tract S 13-6-8

T 11 & 12 N R 9 & 10 W SEWARD Meridian,

containing 5002 acres, more or less

2. LANDS APPROVED

S-13-6-8

All Section	31, T.12N., R.9W., SM	608.
All Section	32, " " " "	640.
All Section	5, T.11N., R.9W., SM	640.
All Section	6, " " " "	610.
All Section	7, " " " "	611.
All Section	18, " " " "	613.
All Section	12, T.11N., R.10W., SM	640.
All Section	13, " " " "	640.
		5002 Acres

containing 5002 acres, more or less.

3. Interest of assignor in said lands: 100%

4. Extent of such interest assigned to assignee: AN UNDIVIDED 25%

5. Overriding royalty reserved herein to assignor: NONE

6. Signed this date: JANUARY 6 1962

PAN AMERICAN PETROLEUM CORPORATION

BY: Willard B. Longshore
(Assignor's Signature)
Its Attorney in Fact

PROVINCE OF ALBERTA)
)
CANADA)
)

BEFORE ME, the undersigned, a Notary Public, within and for said Province of Alberta, on this 6 day of January, 1962, personally appeared Willard B. Longshore, to me personally known to be the identical person who executed the within and foregoing instrument and acknowledged to me that he executed the same as his free and voluntary act and deed for the uses and purposes therein set forth.

IN TESTIMONY WHEREOF, I have hereunto set my hand and official seal the day and year last above written.

AGO 570667

A Notary Public in and for
the Province of Alberta

My commission is held at the

Application for Approval of Assignment

The undersigned assignee hereby requests approval of the above assignment as to all of the lands described in item 1 of the above assignment or such portion thereof as may be approved under applicable law and regulations.

Enclosed with this application are:

(a) Check or money order payable to the Department of Revenue of the State of Alaska covering filing fee of $20.00;

(b) Information and documents, or references thereto, evidencing the qualifications of the undersigned to hold a lease, in compliance with Section 10.31 (c) of the Oil and Gas Leasing Regulations; and

(c) Any bond or reference thereto required by said Regulations.

Any notice in connection with this application or the undersigned's interest in the lease designated in the foregoing assignment may be sent to the undersigned's address set forth in said assignment.

The undersigned agrees to be bound by the provisions of said lease, if the above assignment is approved in whole or in part.

This application discloses and is signed by or on behalf of all persons who will or may, if the above assignment is approved in whole or in part, receive any interest in the lease designated above by virtue of any agreement or understanding, oral or written.

Signed this date: January 19, 1962

ATTEST:

Assistant Secretary

PHILLIPS PETROLEUM COMPANY

By: (Assignee's Signature) Vice President

File No. ADL-CF-17
B1-1

Approval

The above assignment is approved as to the lands described in item 2 thereof, effective as of the date set forth below.

STATE OF ALASKA

Effective date of assignment Jan 31, 1962

By ~~Director, Division of Lands~~
Mineral Leasing Officer

(Submit in triplicate. Must be filed within 90 days after date shown in item 6 of the above assignment form. All copies must be signed in ink.)

AGO 570668

FORM NO. DL-8
SEPT. 1959

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

RECEIVED AUG 24 1962 Division of Lands Dept. of Natural Resources

LEASE NO. ADL 18740

Assignment Affecting Record Title to Oil and Gas Lease

The undersigned assignor, as owner of the record title interest specified in item 3 below in the oil and gas lease designated above, for a good and valuable consideration, does hereby assign to PHILLIPS PETROLEUM COMPANY BARTLESVILLE, OKLAHOMA whose address is

the right, title and interest specified in item 4 below in and to the lands embraced in said lease described in item 1 below, or such portion thereof as the lessor may approve and described in item 2 below, giving and granting to assignee the rights and privileges of a lessee in said lands, to the extent indicated, subject to the reservations of overriding royalties noted in item 5 below:

1. LANDS REQUESTED

S-13-6-28

2. LANDS APPROVED
(Not to be filled in)

All	Section 3, T11N, R10W, SM		640
All	Section 9, " " "		640
All	Section 10, " " "		640
All	Section 11, " " "		640
All	Section 14, " " "		640
All	Section 15, " " "		640
All	Section 16, " " "		640
All	Section 35, T12N, R10W, SM		640
			5120 Acres

T11&12 N., R. 10 W., SEWARD Meridian, containing 5120 acres, more or less

T11&12N., R. 10W., Seward Meridian, containing 5120 acres, more or less.

3. Interest of assignor in said lands: 100%

4. Extent of such interest assigned to assignee: An undivided 25%

5. Overriding royalty reserved herein to assignor: None

6. Signed this date: July 26th, 1962

PAN AMERICAN PETROLEUM CORPORATION

Willard B Longshore
(Assignor's Signature)

Willard B. Longshore
Its Attorney-in-Fact

CERTIFICATE OF ACKNOWLEDGMENT

PROVINCE OF ALBERTA)
CANADA)

BEFORE ME, the undersigned, a Notary Public, within and for said Province of Alberta, on this 26th day of July A.D. 1962, personally appeared WILLARD B. LONGSHORE, to me personally known to be the identical person who executed the within and foregoing instrument and acknowledged to me that he executed the same as his free and voluntary act and deed for the uses and purposes therein set forth.

IN TESTIMONY WHEREOF, I have hereunto set my hand and official seal the day and year last above written.

A Notary Public in and for the
Province of Alberta.

My commission is held at the pleasure of the Lieutenant-Governor of the Province of Alberta

AGO 570669

(CORPORATION ACKNOWLEDGMENT)

STATE OF OKLAHOMA
COUNTY OF WASHINGTON } SS.

On this 14th day of August, 1962, before me MARY HENTON, a notary public, appeared R. B. STEWART to me personally known, who being by me duly sworn did say: that he is the Vice-president of PHILLIPS PETROLEUM COMPANY and that the seal affixed to the above and foregoing instrument is the corporate seal of said corporation, and that said instrument was signed and sealed in behalf of said corporation by authority of its Board of Directors, and said R. B. STEWART acknowledged said instrument to be the free act and deed of said corporation.

Given under my hand and seal this 14th day of August, 1962.

My commission expires: 11-8-65

Mary Henton
Notary Public for the State of Oklahoma

Residing at Bartlesville

whole or in part.

This application discloses and is signed by or on behalf of all persons who will or may, if the above assignment is approved in whole or in part, receive any interest in the lease designated above by virtue of any agreement or understanding, oral or written.

Signed this date: 8-14-62

ATTEST:

PHILLIPS PETROLEUM COMPANY

By R. B. Stewart
(Assignee's Signature) Vice-President

Asst. Secretary

(b) Delaware Corporation authorized to hold Oil & Gas Leases. Statement of Qualification filed in Q-17. There have been no amendments.
B1-1

Approval

The above assignment is approved as to the lands described in item 2 thereof, effective as of the date set forth below.

STATE OF ALASKA

Effective date of assignment August 24, 1962

By ~~Director, Division of Lands~~
Minerals Officer

(Submit in triplicate. Must be filed within 30 days after date shown in item 6 of the above assignment form. All copies must be signed in ink.)

AGO 570670

Application for Approval of Assignment

The undersigned assignee hereby requests approval of the above assignment as to all of the lands described in item 1 of the above assignment or such portion thereof as may be approved under applicable law and regulations.

Enclosed with this application are:

(a) Check or money order payable to the Department of Revenue of the State of Alaska covering filing fee of $20.00;

(b) Information and documents, or references thereto, evidencing the qualifications of the undersigned to hold a lease, in compliance with Section 10.31 (c) of the Oil and Gas Leasing Regulations; and see below

(c) Any bond or reference thereto required by said Regulations.

Any notice in connection with this application or the undersigned's interest in the lease designated in the foregoing assignment may be sent to the undersigned's address set forth in said assignment.

The undersigned agrees to be bound by the provisions of said lease, if the above assignment is approved in whole or in part.

This application discloses and is signed by or on behalf of all persons who will or may, if the above assignment is approved in whole or in part, receive any interest in the lease designated above by virtue of any agreement or understanding, oral or written.

Signed this date: 8-14-62

ATTEST: [signature]
Asst. Secretary

PHILLIPS PETROLEUM COMPANY

By [signature]
(Assignee's Signature) Vice-President

(b) Delaware Corporation authorized to hold Oil & Gas Leases. Statement of Qualification filed in Q-17. There have been no amendments.
B1-1

Approval

The above assignment is approved as to the lands described in item 2 thereof, effective as of the date set forth below.

STATE OF ALASKA

Effective date of assignment August 24, 1962

By [signature]
~~Director, Division of Lands~~
Minerals Officer

(Submit in triplicate. Must be filed within 90 days after date shown in item 6 of the above assignment form. All copies must be signed in ink.)

AGO 570671

FORM NO. DL-8
SEPT. 1959

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Lands

RECEIVED
AUG 24 1962
Division of Lands
Dept. of Natural Resources

LEASE NO. ADL 18771

Assignment Affecting Record Title to Oil and Gas Lease

The undersigned assignor, as owner of the record title interest specified in item 3 below in the oil and gas lease designated above, for a good and valuable consideration, does hereby assign to PHILLIPS PETROLEUM CORPORATION whose address is BARTLESVILLE, OKLAHOMA the right, title and interest specified in item 4 below in and to the lands embraced in said lease described in item 1 below, or such portion thereof as the lessor may approve and described in item 2 below, giving and granting to assignee the rights and privileges of a lessee in said lands, to the extent indicated, subject to the reservations of overriding royalties noted in item 5 below:

1. LANDS REQUESTED

S-13-6-27

2. LANDS APPROVED
(Not to be filled in)

S-13-6-27

All	Section 3, T11N, R 9W, SM		640
All	Section 4, " " "		640
All	Section 8, " " "		640
All	Section 9, " " "		640
All	Section 16, " " "		640
All	Section 17, " " "		640
All	Section 33, T12N, R 9W, SM		640
All	Section 34, " " "		640
			5120 Acres

T 11&12 N, R 9 W, SEWARD Meridian, containing 5120 acres, more or less

T. 11&12N, R. 9W, Seward Meridian, containing 5120 acres, more or less.

3. Interest of assignor in said lands: 100%

4. Extent of such interest assigned to assignee: An undivided 25%

5. Overriding royalty reserved herein to assignor: None

6. Signed this date: July 26th, 1962

PAN AMERICAN PETROLEUM CORPORATION

Willard B. Longshore

(Assignor's Signature)

Willard B. Longshore
Its Attorney-in-Fact

CERTIFICATE OF ACKNOWLEDGMENT

AGO 570672

PROVINCE OF ALBERTA)
CANADA)

BEFORE ME, the undersigned, a Notary Public, within and for said Province of Alberta, on this 26th day of July A.D. 1962, personally appeared WILLARD B. LONGSHORE, to me personally known to be the identical person who executed the within and foregoing instrument and acknowledged to me that he executed the same as his free and voluntary act and deed for the uses and purposes therein set forth.

IN TESTIMONY WHEREOF, I have hereunto set my hand and official seal the day and year last above written.

A Notary Public in and for the
Province of Alberta

My commission is held at the pleasure of the
Lieutenant-Governor of the Province of Alberta

STATE OF OKLAHOMA
COUNTY OF WASHINGTON } SS.

On this 14th day of August, 19 62, before me MARY HENTON, a notary public, appeared R. B. STEWART to me personally known, who being by me duly sworn did say: that he is the Vice president of PHILLIPS PETROLEUM COMPANY and that the seal affixed to the above and foregoing instrument is the corporate seal of said corporation, and that said instrument was signed and sealed in behalf of said corporation by authority of its Board of Directors, and said R. B. STEWART acknowledged said instrument to be the free act and deed of said corporation.

Given under my hand and seal this 14th day of August, 1962.

My commission expires: 11-8-65

Mary Henton
Notary Public for the State of Oklahoma
Residing at Bartlesville

This application discloses and is signed by or on behalf of all persons who will or may, if the above assignment is approved in whole or in part, receive any interest in the lease designated above by virtue of any agreement or understanding, oral or written.

Signed this date: 8-14-62

ATTEST:

Asst. Secretary

PHILLIPS PETROLEUM COMPANY

By R. B. Stewart
(Assignee's Signature) Vice-President

(b) Delaware Corporation authorized to hold Oil & Gas Leases. Statement of Qualification filed in Q-17. There have been no amendments.
Bl-1

Approval

The above assignment is approved as to the lands described in item 2 thereof, effective as of the date set forth below.

STATE OF ALASKA

Effective date of assignment August 24, 1962

By [redacted]
Minerals Officer

(Submit in triplicate. Must be filed within 90 days after date shown in item 6 of the above assignment form. All copies must be signed in ink.)

AGO 570673

P-34-011

Application for Approval of Assignment

The undersigned assignee hereby requests approval of the above assignment as to all of the lands described in item 1 of the above assignment or such portion thereof as may be approved under applicable law and regulations.

Enclosed with this application are:

(a) Check or money order payable to the Department of Revenue of the State of Alaska covering filing fee of $20.00;

(b) Information and documents, or references thereto, evidencing the qualifications of the undersigned to hold a lease, in compliance with Section 10.31 (c) of the Oil and Gas Leasing Regulations; and see below

(c) Any bond or reference thereto required by said Regulations.

Any notice in connection with this application or the undersigned's interest in the lease designated in the foregoing assignment may be sent to the undersigned's address set forth in said assignment.

The undersigned agrees to be bound by the provisions of said lease, if the above assignment is approved in whole or in part.

This application discloses and is signed by or on behalf of all persons who will or may, if the above assignment is approved in whole or in part, receive any interest in the lease designated above by virtue of any agreement or understanding, oral or written.

Signed this date: 8-14-62

ATTEST:

Asst. Secretary

PHILLIPS PETROLEUM COMPANY

By R. B. Stewart
(Assignee's Signature) Vice-President

(b) Delaware Corporation authorized to hold Oil & Gas Leases. Statement of Qualification filed in Q-17. There have been no amendments.
B1-1

Approval

The above assignment is approved as to the lands described in item 2 thereof, effective as of the date set forth below.

STATE OF ALASKA

Effective date of assignment August 24, 1962

By [redacted]
Minerals Officer

(Submit in triplicate. Must be filed within 90 days after date shown in item 6 of the above assignment form. All copies must be signed in ink.)

AGO 570674

FORM NO. DL-8
SEPT. 1959

North Cook Inlet Area
Shell et al. #3 Lease
Property No. 18442

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

Division of Lands

LEASE NO. ADL 18755

Assignment Affecting Record Title to Oil and Gas Lease

The undersigned assignor, as owner of the record title interest specified in item 3 below in the oil and gas lease designated above, for a good and valuable consideration, does hereby assign to

PHILLIPS PETROLEUM COMPANY

whose address is 1300 SECURITY LIFE BUILDING
DENVER, COLORADO 80202

the right, title and interest specified in item 4 below in and to the lands embraced in said lease described in item 1 below, or such portion thereof as the lessor may approve and described in item 2 below, giving and granting to assignee the rights and privileges of a lessee in said lands, to the extent indicated, subject to the reservations of overriding royalties noted in item 5 below:

1. LANDS REQUESTED

Township 12 North, Range 9 West, S.M.

Section 19: SE¼
Section 20: S½ and NE¼
Section 29: All
Section 30: All

Township 12 North, Range 10 West, S.M.

Section 25: SE¼
Section 36: All

Township 11 North, Range 10 West, S.M.

Section 1: All

2. LANDS APPROVED
(Not to be filled in)

SAME AS ITEM #1

..... R 9W Meridian,

ntaining 3326.00 acres, more or less.
Decision 9/1/67

1

None

AGO 570675

COUNTY OF LOS ANGELES }

On this 24th day of May, 1967, before me

Mildred M. Crawford, a Notary Public in and for said County and State, residing therein, duly commissioned and sworn, personally appeared D. E. CLARK, known to me to be the person whose name is subscribed to the within instrument as the Attorney In Fact of Shell Oil Company, and acknowledged to me that he subscribed the name of Shell Oil Company thereto as principal, and his own name as Attorney In Fact.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal, at my office, in said County and State, the day and year in this certificate first above written.

Mildred M. Crawford

Mildred M. Crawford
Name (Typed or Printed)
Notary Public in and for said County and State

My Commission expires December 11, 1967

OFFICIAL SEAL
MILDRED M. CRAWFORD
NOTARY PUBLIC - CALIFORNIA
PRINCIPAL OFFICE IN
LOS ANGELES COUNTY

ltr 6-26-67

Application for Approval of Assignment

The undersigned assignee hereby requests approval of the above assignment as to all of the lands described in item 1 of the above assignment or such portion thereof as may be approved under applicable law and regulations.

Enclosed with this application are:

(a) Check or money order payable to the Department of Revenue of the State of Alaska covering filing fee of $20.00;

(b) Information and documents, or references thereto, evidencing the qualifications of the undersigned to hold a lease, in compliance with Section 10.31 (c) of the Oil and Gas Leasing Regulations; and

(c) Any bond or reference thereto required by said Regulations.

Any notice in connection with this application or the undersigned's interest in the lease designated in the foregoing assignment may be sent to the undersigned's address set forth in said assignment.

The undersigned agrees to be bound by the provisions of said lease, if the above assignment is approved in whole or in part.

This application discloses and is signed by or on behalf of all persons who will or may, if the above assignment is approved in whole or in part, receive any interest in the lease designated above by virtue of any agreement or understanding, oral or written.

Signed this date: June 16, 1967

PHILLIPS PETROLEUM COMPANY

By _____
(Assignee's Signature)

Its Attorney-in-Fact



The above assignment is approved as to t bed in item 2 thereof, effective as of the date set forth below.

STATE OF ALASKA

Effective date of assignment JUN 16 1967

By _____
Director, Division of Lands PEDRO DENTON
Minerals Officer

(Submit in triplicate. Must be filed within 90 days after date shown in item 6 of the above assignment form. All copies must be signed in ink.)

AGO 570676

7. Assignor warrants this assignment to be free and clear of all liens, clouds and encumbrances caused, suffered or created by, through or under Assignor, but not otherwise, except the North Cook Inlet Unit Agreement and the North Cook Inlet Unit Operating Agreement, both dated November 1, 1966.

RDA

Form DL-8 (O&G)
May, 1966

LEASE NO. ADL 17590
EFFECTIVE DATE OF LEASE March 1, 1962

State of Alaska
Department of Natural Resources
Division of Lands
ALK 1645

Assignment Affecting Record Title to Oil and Gas Lease

The undersigned assignor, as owner of the record title interest specified in item 3 below in the oil and gas lease designated above, for a good and valuable consideration, does hereby assign to Phillips Petroleum Company, a Delaware corporation whose address is Bartlesville, Oklahoma the right, title and interest specified in item 4 below in and to said lease insofar as it covers the lands described in item 1 or such portion thereof as the lessor may approve and describe in item 2 below, giving and granting to assignee the rights and privileges of a lessee in said lands, to the extent indicated, subject to the reservations of overriding royalties noted in items 5 and 6 below:

1. LANDS REQUESTED

Section 21: W 1/2
Section 28: W 1/2

T 12 N, R 9 W, S. M. Meridian, containing 640 acres, more or less.

2. LANDS APPROVED
(Not to be filled in)

SAME AS ITEM #1

T _____, R _____, _____ Meridian, containing _____ acres, more or less.

3. Interest of assignor in said lease: 1/3rd
4. Extent of such interest assigned to assignee: All
5. Overriding royalty reserved herein to assignor: None
6. Overriding royalty previously reserved: None
7. Signed this date: May 26, 1967
8. See Rider attached

ATTEST:
Assistant Secretary

ATLANTIC RICHFIELD COMPANY
(Assignor's Signature)
By W. F. Kieschnick Jr. ad
W. F. Kieschnick, Jr.
Vice President

THE UNITED STATES OF AMERICA)
) ss.
STATE OF Texas)

This certifies that on the 26th day of May, 19 67, before me a notary public in and for the State of Texas, duly commissioned and sworn, personally appeared W.F.Kieschnick, Jr. to me known and known to me to be the person described in and who executed the foregoing assignment, who then after being duly sworn according to law, acknowledged to me under oath that he executed same freely and voluntarily for the uses and purposes therein mentioned, and for Atlantic Richfield Company, a Pennsylvania corporation, as its Vice President.

WITNESS my hand and official seal the day and year in this certificate first above written.

Notary Public for Dallas County, Texas
My Commission expires: June 1. 1967

AGO 570678

W6-23-67 mjr



Application for Approval of Assignment

The undersigned assignee hereby requests approval of the above assignment as to all of the lands described in item 1 of the above assignment or such portion thereof as may be approved under applicable law and regulations.

Enclosed with this application are:

(a) Cash, check or money order payable to the Department of Revenue of the State of Alaska covering filing fee of $20.00;

(b) Any bond or reference thereto required by said regulations.

Any notice in connection with this application or the undersigned's interest in the lease designated in the foregoing assignment may be sent to the undersigned's address set forth in said assignment.

The undersigned agrees to be bound by the provisions of said lease, if the above assignment is approved in whole or in part.

This application discloses and is signed by or on behalf of all parties who will or may, if the above assignment is approved in whole or in part, receive any interest in the lease designated above by virtue of any agreement or understanding, oral or written and constitutes certification that each such party is qualified to hold Alaska State Oil and Gas Leases pursuant to Section 503.1 of the Oil and Gas Leasing Regulations.

Signed this date: June 16, 1967

PHILLIPS PETROLEUM COMPANY

By: _____
(Assignee's Signature)

It's Attorney-in-Fact

Approval

The foregoing assignment is approved as to the lands described in item 2 thereof, effective as of the date set forth below.

STATE OF ALASKA

Effective date of assignment JUN 16 1967

By _____

PEDRO DENTON
Minerals Officer

(Submit in triplicate. Must be filed within 90 days after final execution by the assignee. All copies must be signed in ink.)

AGO 570679

APUC ORDERS

U-M GAS LINE

ORDER NO. 1

ORDER NO. 2

(including dissenting opinion by Gordon Zerbetz)

(PARTIAL) EXEMPTION OF U-M TRANSMISSION LINE FROM APUC JURISDICTION

AGO 570681

December 31, 1970

STATE OF ALASKA

BEFORE THE ALASKA PUBLIC UTILITIES COMMISSION

In the Matter of the Certification of UNION OIL COMPANY OF CALIFORNIA and MARATHON OIL COMPANY

U-70-73

ORDER NO. 1

ORDER GRANTING TEMPORARY EXEMPTION

On December 18, 1970, the Commission received a request on behalf of the above-named parties for exemption from the certification provisions of AS 42.05.221, which provides:

> "Sec. 42.05.221. Certificates required. (a) No public utility may operate and receive compensation for providing a commodity or service after January 1, 1971 without first having obtained from the commission under this chapter a certificate declaring that public convenience and necessity require or will require the service . . . ."

In the opinion of the Commission, the request poses problems sufficiently similar to those presented in Commission Cause No. U-70-85 to warrant the same approach utilized in Order No. 1 in that docket (copy attached).

FINDINGS

THE COMMISSION FINDS, good cause exists for temporarily exempting Union Oil Company of California and Marathon Oil Company from complying with AS 42.05.221 pending final decision on the request for exemption pursuant to AS 42.05.711(d).

U-70-73

93

AGO 570682

ORDER

THE COMMISSION ORDERS:

1. Upon the request of the parties named in the caption of this proceeding for exemption from complying with AS 42.05.221, said parties are temporarily exempted from complying with AS 42.05.221 pending final decision on the issues raised pursuant to AS 42.05.711(d), upon the following condition:

That the parties must submit a complete application for a certificate of public convenience and necessity (Commission Form PU 101) on or before February 1, 1971.

2. Failure to comply with the condition specified in Paragraph (1) shall result, without necessity of further order, in termination of the temporary exemption.

3. The applications shall be accompanied, either individually or collectively, by whatever additional argument or information may be necessary to complete the presentations of the parties in support of the request for exemption. Factual matters contained in the request for exemption, if not also provided in the applications, shall be verified by persons having personal knowledge of such factual matters.

4. Pending final disposition of the request for exemption, Union Oil Company and Marathon Oil Company shall not enter into any new contracts for the sale of natural gas without affording the Commission a prior opportunity of at least thirty (30) days in which to review each said contract. Any such contracts entered into without prior submission to the Commission shall be null and void.

5. The Commission shall schedule such further proceedings, including public notice and hearing (consolidated or separate) as it deems warranted.

By Direction of the Commission:

DATED at Anchorage, Alaska this 31st day of December, 1970.

ALASKA PUBLIC UTILITIES COMMISSION

Don Hall

Don Hall
Executive Director

STATE OF ALASKA

September 28, 1971

BEFORE THE ALASKA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of UNION OIL COMPANY OF CALIFORNIA and MARATHON OIL COMPANY for Exemption of its Kenai-Nikiski Natural Gas Pipeline from Regulation Pursuant to AS 42.05.711(d)	)	U-70-73 ORDER NO. 2

ORDER DISMISSING APPLICATION FOR CERTIFICATE AND GRANTING PARTIAL EXEMPTION FROM THE PROVISIONS OF AS 42.05

The UNION OIL COMPANY OF CALIFORNIA (UNION) and MARATHON OIL COMPANY (MARATHON) each own fifty percent of the Kenai-Nikiski Pipeline (Pipeline) located in Section 21, T7N, R12W of the Seward Meridian. On December 18, 1970 Union and Marathon (herein after referred to as "Applicants") jointly filed an application with the Commission under AS 42.05.711(d) for exemption of the pipeline from all provisions of the Alaska Public Utilities Commission Act, and rules and regulations promulgated thereunder, except those pertaining to safety standards.

The above application indicates that approximately 160,000 - 170,000 Mcf of gas were being transported daily through the pipeline. Of that total, it appears that about 900 Mcf per day are delivered through a portion of the pipeline to the City of Kenai for use in its municipal gas distribution system.

On December 31, 1970, the Commission entered its Order No. 1 in this proceeding which granted the Applicants

temporary exemption from compliance with AS 42.05.221 pending final decision of the issues in this matter on the condition that a complete application for a certificate of public convenience and necessity would be filed by the Applicants on or before February 1, 1971. The order further provided that no new agreements for the sale of natural gas would be entered into without first affording the Commission an opportunity of at least thirty (30) days in which to review each proposed contract.

Union and Marathon, on January 29, 1971, each filed a separate application for a certificate of public convenience and necessity to operate a natural gas transmission pipeline, but continued to urge consideration of their previous request for partial exemption in preference to their application for a certificate.

Subsequent to the Applicants' filing for an exemption, but prior to the application being noticed to the public, the Alaska Public Service Corporation (APSC) requested an opportunity to intervene and to oppose the granting of such exemption because of the disclosure in the application that it was proposing to sell gas from the Pipeline to Chugach Electric Association, Inc. On January 29, 1971, the request to intervene and to oppose the granting of an exemption was withdrawn by the APSC. However, in a letter to the Commission, dated August 30, 1971, the President of APSC informed the Commission that the reason it did not object to the exemption of Applicants was ". . . because we believed the Commission would not allow the invasion of our Service Area during the course of such exemption."

gas distribution utility subsidiary of APC via APC?

AGO 570686

The aforementioned applications were noticed to the public and all known interested parties on March 6, 1971. No opposition to, or support for, the application was received in response to the public notice.

It is the position of the Applicants that, except for safety considerations, the provisions of AS 42.05 are not applicable to the type of operations performed or contemplated by the Pipeline. Clearly in contrast, the Applicants do transmit and sell natural gas to the City of Kenai, which in turn sells it to Wildwood Air Force Station and to Kenai Utility Service Corporation for resale to its individual commercial and residential customers. A natural gas utility as defined in AS 42.05.701(2) (D) includes any corporation or company furnishing, by transmission or distribution, natural gas to the Alaska public for compensation. This definition, viewed by itself, might lead to the assumption that since the individual commercial and residential consumers are not being served directly by the Applicants, the Applicants are not a public utility. AS 42.05.701(5), however, provides that the "public" or "general public" includes any utility purchasing or paying for the transmission of natural gas which is resold to ten or more customers; thus the City of Kenai and the Kenai Utility Service Corporation are the "public" in addition to being utilities. Sale of natural gas to the City of Kenai (the public), by statutory definition, make the Applicants a public utility.

It is apparent to the Commission that the primary purpose and use of the Pipeline is to provide natural gas to the Applicants' affiliated industrial manufacturing interests

and to other related gas and oil production activities. The Commission understands the reluctance of the Applicants to submit all of their pipeline operations to regulation as a public utility, particularly in view of the extremely small percentage of the total pipeline capacity dedicated to public utility service. On the other hand, the Commission must recognize its obligation to protect the interests of all ultimate utility customers who depend on the Applicants for the gas they use regardless of the fact that their usage is only a minuscule part of the gas transmitted by the Pipeline. The Commission must be assured that once utility service has been offered to the public, it will continue to be offered for a reasonable period at rates which are just and fair. Further, the Commission must be in a position to ascertain periodically that rates being charged to the utilities are consistent with those being charged to other users of the Pipeline and that the rates of return for sales to utilities are not excessive. Finally, the Commission should have a current knowledge of the quantity of gas the Applicants are prepared to deliver for public utility usage and the time periods over which such deliveries can be made.

AS 42.05.711(d) provides that the Commission, on finding that no legitimate public interest would be served, may exempt a utility from all or any portion of the Act. It would appear that the majority of Applicants' pipeline activities can properly be exempted from regulation, provided sufficient safeguards are retained to guarantee that the rate payers using the natural gas supplied by the Pipeline

will receive adequate regulatory protection. Safety matters, for which no exemption has been requested, should continue to be regulated by the Commission in accordance with the authority delegated to it through the Federal Government's Natural Gas Pipeline Safety Act of 1968, as amended.

FINDINGS

THE COMMISSION FINDS:

1. Union Oil Company of California and Marathon Oil Company, to the extent of their ownership, control and operation of the Kenai-Nikiski Pipeline, are a public utility as defined by AS 42.05.701(2) (D) and AS 42.05.701(5) (B).

2. Union Oil Company of California and Marathon Oil Company, in their ownership, control and operation of the Kenai-Nikiski Pipeline, should be exempted from the provisions of AS 42.05 except as it relates to or affects:

A. The terms, conditions or pricing of natural gas sales to public utilities;

B. The quality of service rendered to public utilities as customers;

C. The safety of operations of the pipeline and its related facilities and appurtenances.

3. No legitimate public interest will be served by regulating any of the operations of Union Oil Company of California and Marathon Oil Company except to the extent indicated in Finding No. 2 above.

ORDER

THE COMMISSION ORDERS:

1. Order No. 1 in this proceeding is hereby rescinded.

2. The application of Union Oil Company of California and Marathon Oil Company for a certificate of public convenience and necessity to furnish natural gas transmission service is dismissed without prejudice.

3. Subject to the conditions of this Order, the application of Union Oil Company of California and Marathon Oil Company, as owners and operators of the Kenai-Nikiski Pipeline, for an exemption from the provisions of AS 42.05 is granted in part. The Commission retains jurisdiction to the extent that Union Oil Company of California and Marathon Oil Company, as owners and operators of the Kenai-Nikiski Pipeline shall:

a) File with the Commission within thirty (30) days of the effective date of this Order, copies of all contracts, agreements, or arrangements for the sale or delivery of natural gas in effect on the effective date of this Order.

b) File with the Commission within thirty (30) days after execution, a copy of any new contract, agreement, or arrangement or any modification, alteration or extension of an existing contract, agreement, or arrangement for the sale or delivery of natural gas.

c) Obtain prior written approval of the Commission before placing in effect any new contract, agreement, or arrangement or any

Does this not apply to APC contract?

AGO 570690

modification, alteration or extension of an existing contract, agreement, or arrangement for the sale of natural gas to an utility certificated by the Commission.

applicability to APC "extension"?

d) Make available to the Commission, its employees, agents, and consultants for inspection and examination, at all reasonable times, the accounts, books, records, maps, inventories, appraisals, valuations, and/or other reports and documents of the pipeline operation which may be required to evaluate the justice, fairness and reasonableness of its contracts, agreements, and arrangements for the sale of natural gas to certificated public utilities, and to determine the quality of service being rendered.

Applicable to APC!

e) Comply with all State, Federal and Commission rules, regulations, orders, or procedures relating to natural gas pipeline safety.

4. The Commission retains jurisdiction to investigate all complaints filed by any certificated public utility to which the sale or delivery of natural gas is being made and to exercise all provisions of AS 42.05 in the resolution of such complaints.

AGD 570691

5. The exemption granted herein is subject to modification or revocation after thirty (30) days notice to the Union Oil Company of California and the Marathon Oil Company, including an opportunity to be heard if requested by the parties in writing.

By Direction of the Commission (Commissioner Zerbetz, dissenting, filed a Dissenting Statement appended hereto):

DATED at Anchorage, Alaska this 28th day of September, 1971.

ALASKA PUBLIC UTILITIES COMMISSION

J. Lowell Jensen

J. Lowell Jensen
Deputy Director

AGO 570692

-70-73 (2)

STATE OF ALASKA

BEFORE THE ALASKA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of UNION OIL COMPANY OF CALIFORNIA and MARATHON OIL COMPANY for Exemption of its Kenai-Nikiski Natural Gas Pipeline from Regulation Pursuant to AS 42.05.711(d)	U-70-73 ORDER NO. 2

ORDER DISMISSING APPLICATION FOR CERTIFICATE AND GRANTING PARTIAL EXEMPTION FROM THE PROVISIONS OF AS 42.05
(DISSENT OF COMMISSIONER GORDON J. ZERBETZ)

I cannot agree with the decision of the majority which would allow Union Oil Company of California and Marathon Oil Company jointly to operate as a public utility without a certificate of public convenience and necessity in violation of AS 42.05.701(5). The majority opinion admits that applicant is a utility subject to certification but chooses to exempt it for various reasons including apparently the relatively small percentage of the operation which would be considered to be in public use. The size of the utility operation should not be used as a measure of determining the Commission's primary mission to protect the public. Furthermore, this particular operation represents the entire gas supply of the principal cities on the Kenai Peninsula and to the Wildwood Air Force Station.

APC not included! Yet they had a contract as of 1967?

Applicant contends that customers other than the City of Kenai are affiliated interests and that service to these affiliates would not place applicant in a public utility category. It is worthy of note that the other customers are not in the same ownership entity and though there

AGO 570693

are less than 10 of this type of customer their existence as separate entities strengthens my moral conviction that applicant should be treated as a public utility.

Also worthy of note is applicant's disclosure of an attempt to provide services in an area that has already been certificated to another gas utility. Granting of a certificate to one utility and granting an exemption to another for an operation in the same service area cannot but lead to regulatory difficulties in the future.

What/Who that?

The majority decision would retain safety responsibility for this gas pipeline in spite of exemption. The creation of this special utility category could necessitate special handling of general safety orders which would add an unnecessary element of confusion to the Commission's regulatory procedures.

Final and timely consideration should also include the environmental aspect of this exemption. At a time when the Commission is involved in a vigorous program to balance essential utility services with ecological considerations, the jurisdiction of the Commission should be extended to the fullest extent allowed by the existing statutes.

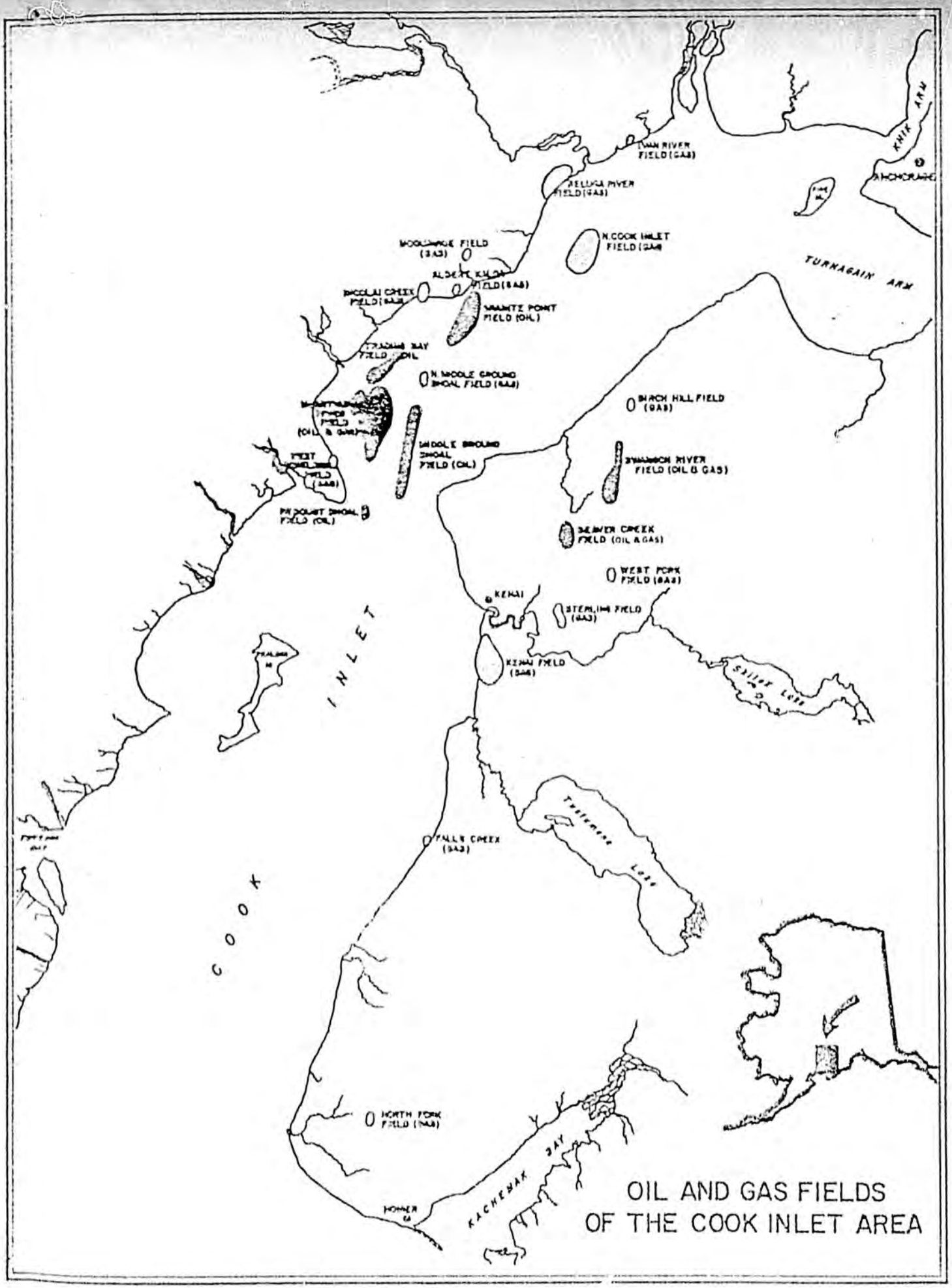
DATED at Anchorage, Alaska this 28th day of September, 1971.

ALASKA PUBLIC UTILITIES COMMISSION

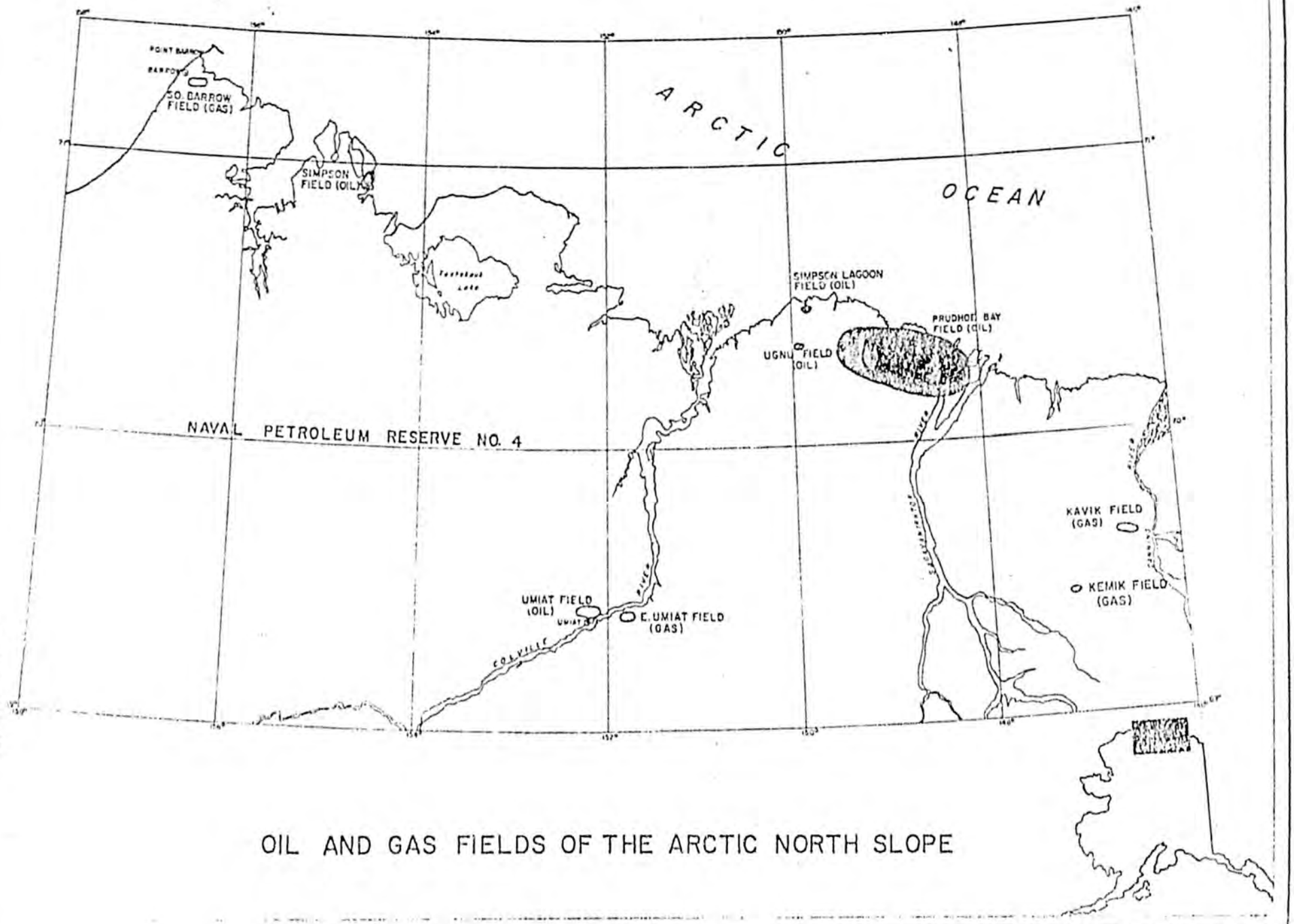
Gordon J. Zerbetz
Commissioner

AGO 570694

COOK INLET OIL + GAS FIELDS


KNIK ARM
ANCHORAGE
TURNAGAIN ARM
COOK INLET
KENAI
SKILAK LAKE
TUSTUMENA LAKE
HOMER
KACHEMAK BAY
N. COOK INLET FIELD (GAS)
BIRCH HILL FIELD (GAS)
SWANSON RIVER FIELD (OIL & GAS)
BEAVER CREEK FIELD (OIL & GAS)
WEST FORK FIELD (GAS)
STERLING FIELD (GAS)
KENAI FIELD (GAS)
FALLS CREEK (GAS)
NORTH FORK FIELD (GAS)
N. MIDDLE GROUND SHOAL FIELD (GAS)
MIDDLE GROUND SHOAL FIELD (OIL)
TRADING BAY FIELD OIL
MCARTHUR RIVER FIELD (OIL & GAS)
PRODUCT SHOAL FIELD (OIL)
OIL AND GAS FIELDS
OF THE COOK INLET AREA

AGO 570695



AGO 570697

OIL AND GAS FIELDS OF THE ARCTIC NORTH SLOPE

BEAVER CREEK GAS FIELD

Operator: Marathon

Other Participants: Union Oil

Discovered: 1967

Production started: 1973

Number of wells (as of 2/75): 1 producer, 0 shut-in

Current producing rate (2/75): 7,249 MCF/month, 259 MCF/day

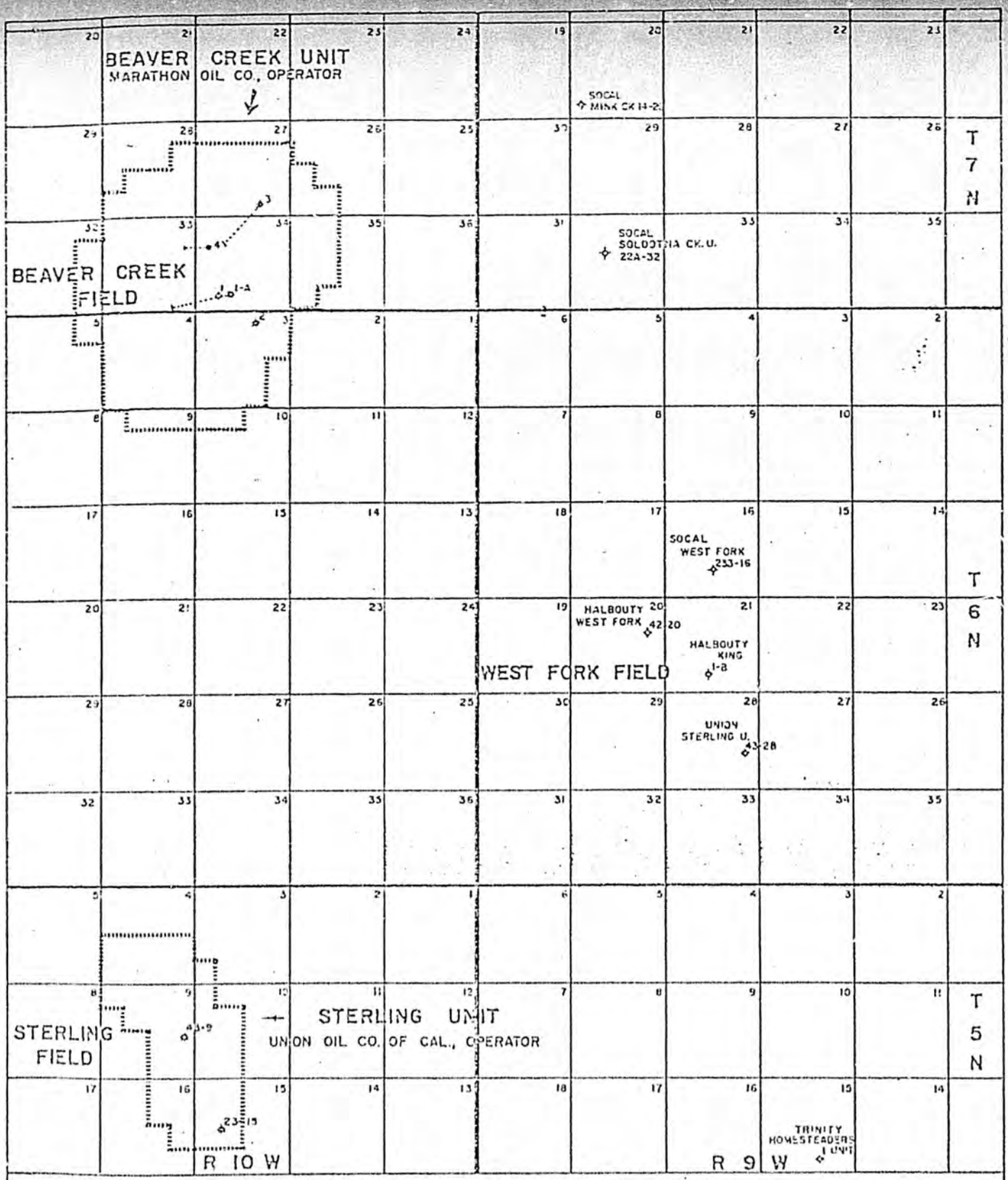
Estimated remaining reserves: 400,000 MMCF

Gas utilization: Gas lift gas

State royalty interest: 0

General onshore location: Eastside Cook Inlet, see attached map.

Comments:
This field is a probable source of gas for the proposed Pacific Lighting LNG project near Kenai.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

BEAVER CREEK, STERLING AND WEST FORK FIELDS

AGO 570699

SCALE: 4,000' 0 4,000' 8,000' 12,000'

APRIL 1, 1974

BELUGA RIVER GAS FIELD

Operator: Socal

Other participants: Shell and Arco

Discovered: 1962

Production started: 1968

Number of wells (as of 2/75): 1 producing, 4 shut-in

Current producing rate (2/75): 507,126 MCF/month, 18,112 MCF/day

Estimated remaining reserves: 700,00 MMCF

Gas utilization: Chugach Electric Assoc.

Current wellhead value: $0.163/MCF, escalates 1¢/MCF every 5 years

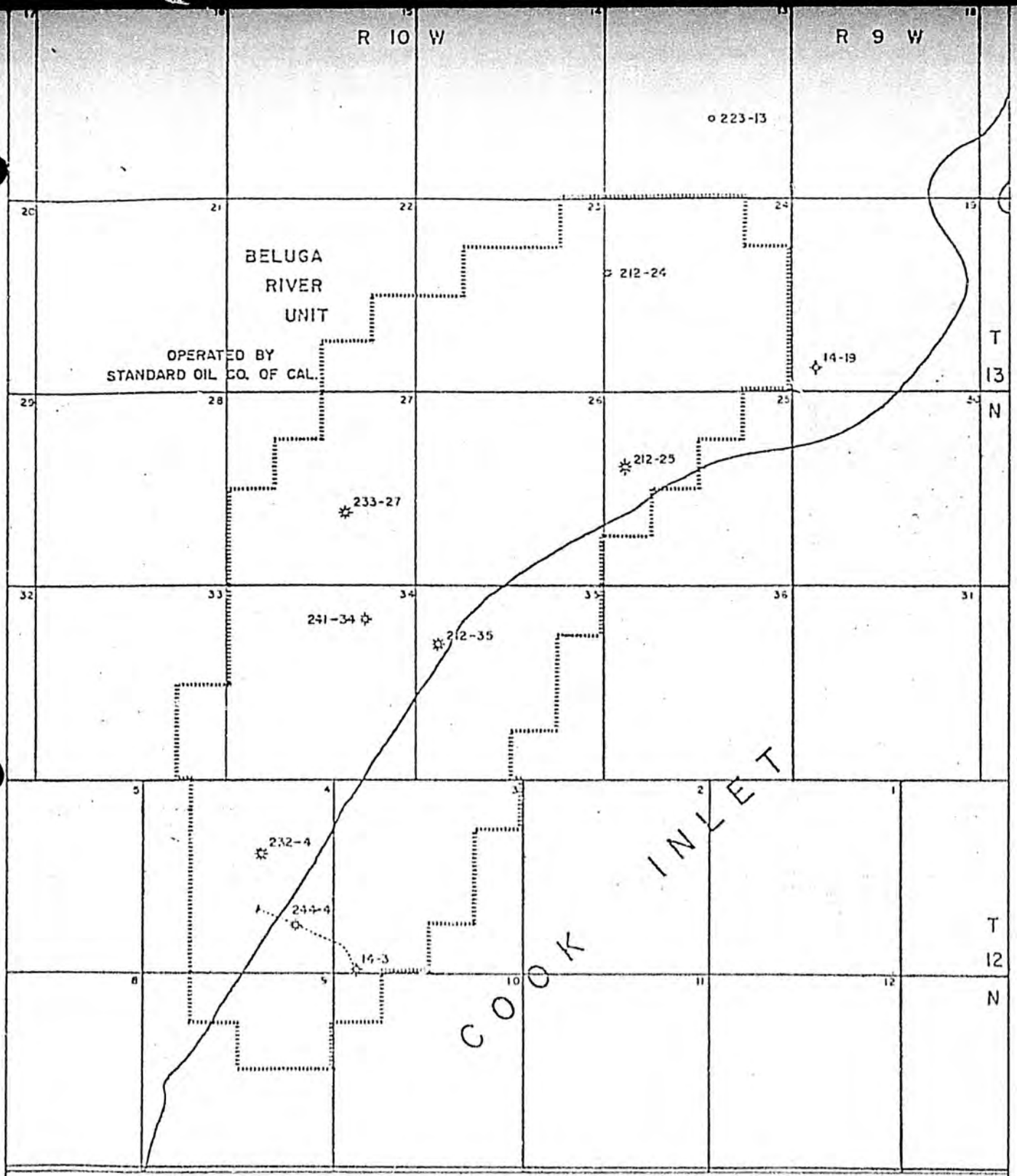
State royalty interest: 7.9862%

Gas sales (1974): 15,182 MCF/D

Possible inkind royalty rate: 1318 MCF/D

General onshore location - Westside Cook Inlet, see attached map.

Comments:
A 6% annual increase in gas production is predicted for this field. Future gas sales are an extrapolation of the past trend which reflects a continuing population and industry growth in the area.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

BELUGA RIVER GAS FIELD

SCALE: 2,000' 0 2,000' 4,000' 6,000'

AGO 570701

APRIL 1, 1974

NORTH COOK INLET GAS FIELD

Operator: Phillips Pet. Co.

Other participants: None

Discovered: 1962

Production started: 1969

Number of wells (as of 2/75): 7 producing, 1 shut-in

Current producing rate (2/75): 4,194,850 MCF/month, 149,816 MCF/day

Estimated remaing reserves: 1,500,00 MMCF

Gas utilization: LNG Plant

X Current wellhead value: $0.3305/MCF

State royalty interest: 12.5%

Gas sales (1974): 120,797 MCF/D gross

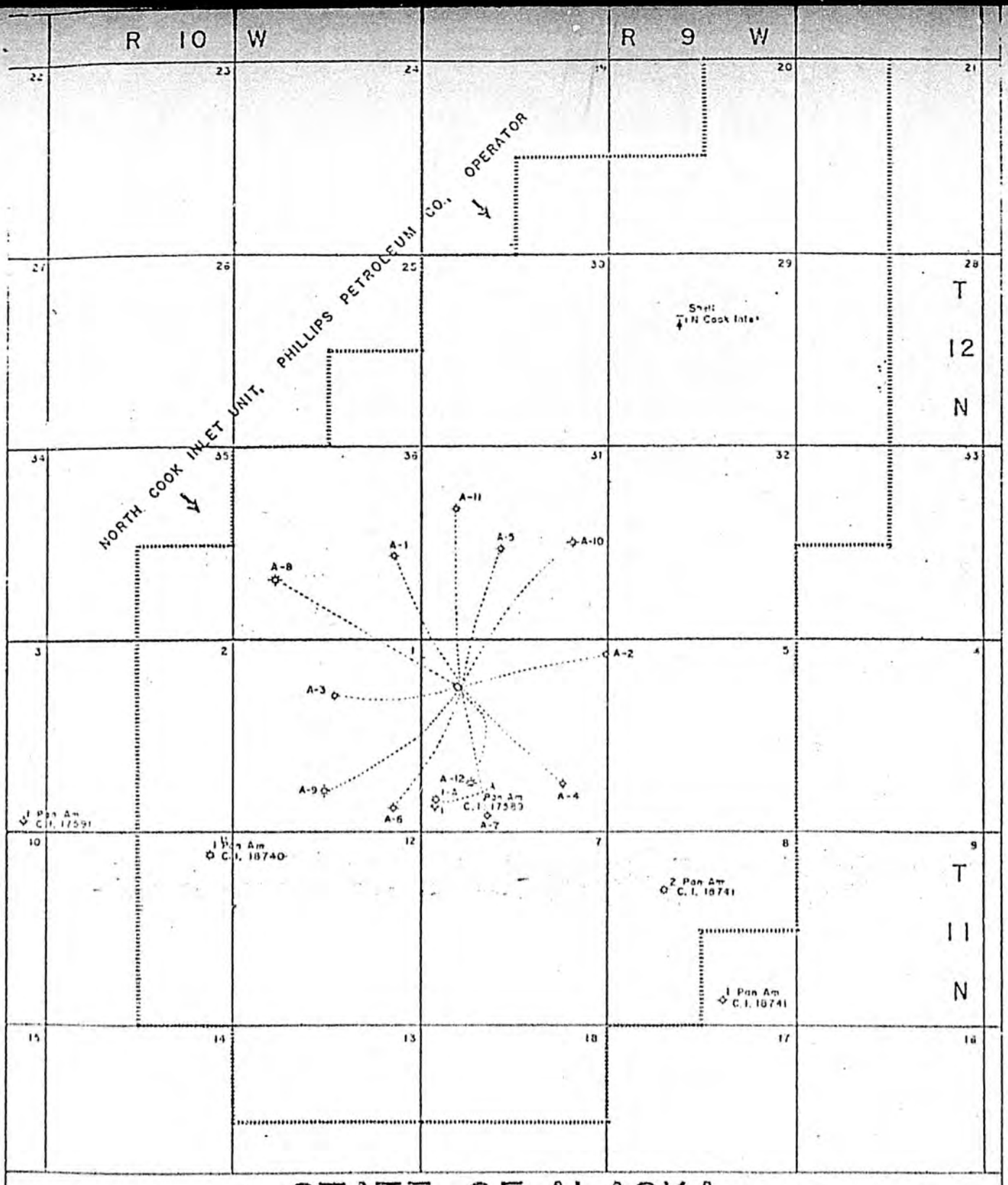
Possible inkind royalty: 17,257 MCF/D

General onshore location: Nikiski, eastside Cook Inlet

Comments:
This Phillips Petroleum Company operated unit delivers a fixed volume of gas for LNG manufacture and sale to Japan. The wellhead value has been increased by contract renegotiation with the Japanese from 10.45¢/MCF to 15.31¢/MCF on 3/12/74, to 28.78¢/MCF on 10/1/74, and to 33.05¢/MCF on 1/1/75. A contract with a new purchaser, NW Natural Gas Co. of Oregon, has been negotiated and is now in the courts. This new sale amounting to 28 MMCF/D should start in mid 1976 at a current Kenai dock price of 80¢/MCF with a 2¢/MCF/yr escalation. With escalation and plant costs it is estimated that the mid 1976 wellhead value for the new sale will be 43¢/MCF.

Kenai Field 7.17 million cf/day (average)
Cyclic supply max 4.95 mil cf/day
min 9.25 " "
based on 1976 production

AGO 570702



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

NORTH COOK INLET FIELD

SCALE: 2,000' 0 2,000' 4,000' 6,000'

APRIL 1, 1974

AGO 570703

KENAI GAS FIELD

Gene Griffin

Operator: Union Oil

{34.8¢/cf.} Royalty

Other participants: Arco, Marathon, Socal

Discovered: 1959

Production started: 1961

Number of wells (as of 2/75): 19 producing, 0 shut-in

Current producing rate (2/75): 6,324,540 MCF/month, 225,876 MCF/day

Estimated remaining reserves: 2,400,000 MMCF

Gas utilization (major): Collier Carbon and Chemical Plant (19%), LNG Plant (30%), Swanson River Oil Field Repressurization (19%), Anchorage and Kenai Residential and Commercial Consumers (32%).

Current wellhead value: Collier Carbon = $0.17/MCF, escalates 1¢/MCF every 5 years.
Phillips LNG Plant = $0.38/MCF
Swanson River Rental = $0.16/MCF
Anchorage Natural Gas PL. = $0.22/MCF, escalates 2¢/MCF every 5 years. Special deliverability charge of 19.5¢/MCF minimum will be added to 22¢/MCF base charge starting 7/1/75.

State royalty interest: Shallow 3.6164% ---------- Deep 1.1407%

Gas sales (1974): 187,474 MCF/D gross

Possible inkind royalty: 6,196 MCF/D

General onshore location - Eastside Cook Inlet, see attached map.

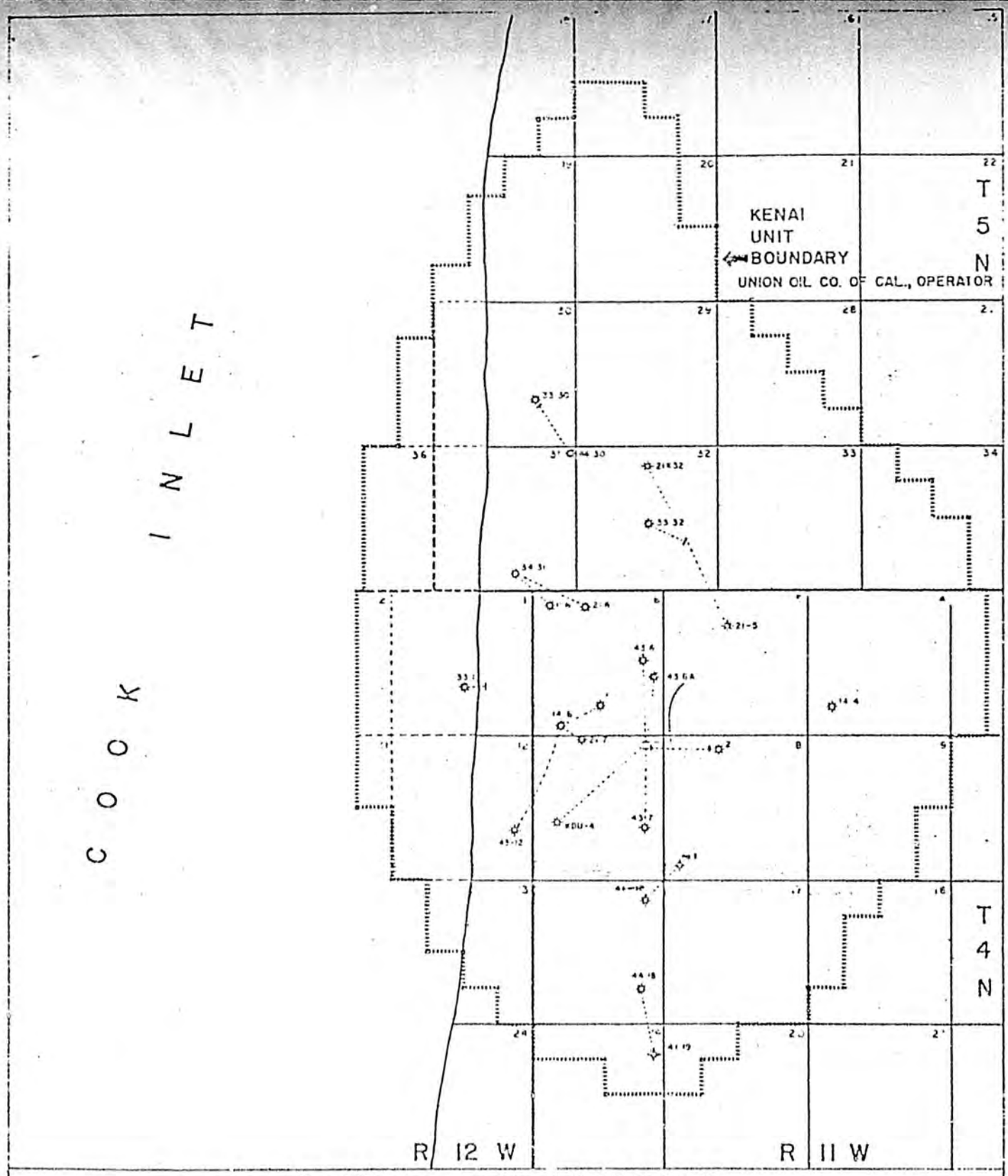
Comments:
Gas sales are predicted to steadily increase even though west side casinghead gas partially displaces Kenai dry gas. Previously flared wet gas from Cook Inlet oil fields became available to the market in October 1972 upon completion of pipeline and compression facilities, to displace dry gas purchased by Collier Chemical Plant and Phillips LNG Plant, and dry gas purchased for injection into the Swanson River Oil Field pressure maintenance project. Gas production is about 84% from Sterling (shallow) pools and 14% from the Tyonek (deep) pool. The federal government has the major royalty interest.

Kenai gas sales to Collier are predicted to increase 2% as the wet gas supply declines until mid 1977, when a planned plant expansion will add 65 MMCF/D.

MCF 6.71

AGO 570704

capacity making a total from Kenai of about 100 MMCF/D. The LNG plant demand should be static until mid 1976 when a new contract, now in the courts, will add 12 MMCF/D in sales to NW Natural Gas Co. in Oregon making total Kenai gas purchases 62 MMCF/D. Alaska Pipeline is predicted to continue its 8% annual increase due to population growth and expansion of the domestic gas systems in Anchorage. Use of Kenai gas on a rental basis for injection in the Swanson River Oil Field reservoir pressurization project is estimated to decline at 15%. In summary, Kenai gas sales are predicted to increase at 5% annually to a mid 1977 average of 214 MMCF/D, when Collier plant expansion will increase sales to 276 MMCF/D; thereafter, total sales should increase at 4% annually.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

KENAI FIELD

AGO 570706

SCALE 1/2 0 1/2 1 1 1/2 miles

APRIL 1, 1973

MCARTHUR RIVER GAS FIELD

Operator: Arco, Marathon and Union

Other participants: Amoco, Phillips, Skelly and Socal

Discovered: 1968

Production started: 1969

Number of wells (as of 2/75): 5 producing, 0 shut-in

Current producing rate (2/75): 624,846 MCF/month; 22,316 MCF/day

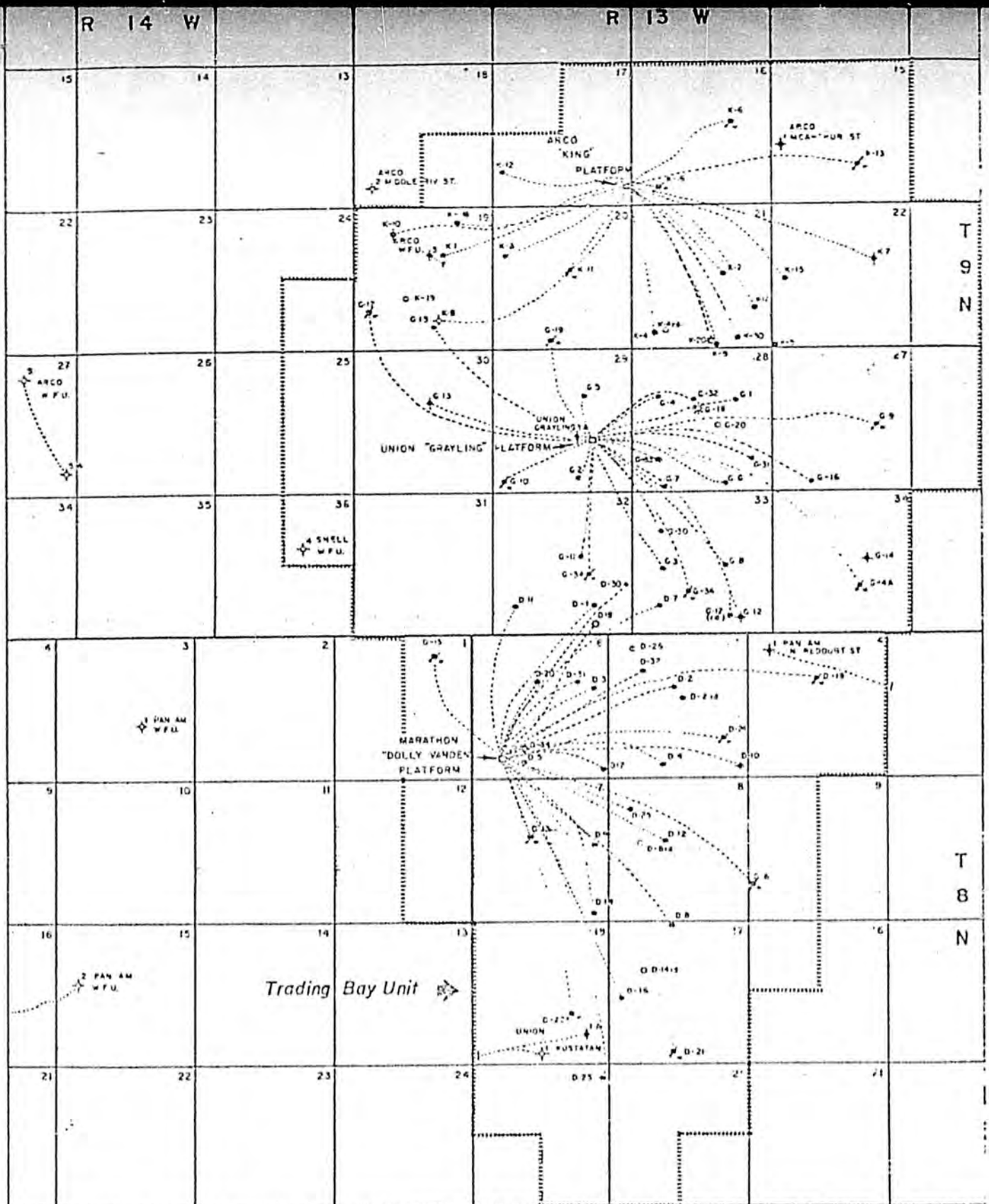
Estimated remaining reserves: 800,000 MMCF

Gas utilization: Used to run equipment on platforms. No sales

State royalty interest: 12.5%

General onshore location: Nikiski, eastside Cook Inlet, see attached map.

Comments:
This field is a probable source of gas for the proposed Pacific Lighting LNG project near Kenai. Gas pipelines from the McArthur River Field platforms to the westside shore facility and from there across Cook Inlet to Nikiski are installed and are being used to ship casinghead gas to market. These same pipelines are available for the dry gas.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
AGO 570/708

ANCHORAGE, ALASKA

MCARTHUR RIVER FIELD

SCALE: 1/2 0 1/2 1 1 1/2 miles

APRIL 1, 1974

NICOLAI CREEK GAS FIELD

Operator: Texaco

Other participants: Superior Oil

Discovered: 1966

Production started: 1968

Number of wells (as of 2/75): 1 producing, 2 shut-in

Current producing rate (2/75): 597 MCF/month, 21 MCF/day

Estimated remaing reserves: 50,000 MMCF

Gas utilization: Fuel for production and transmission equipment for Granite Point Field

Current wellhead value: $0.151/MCF

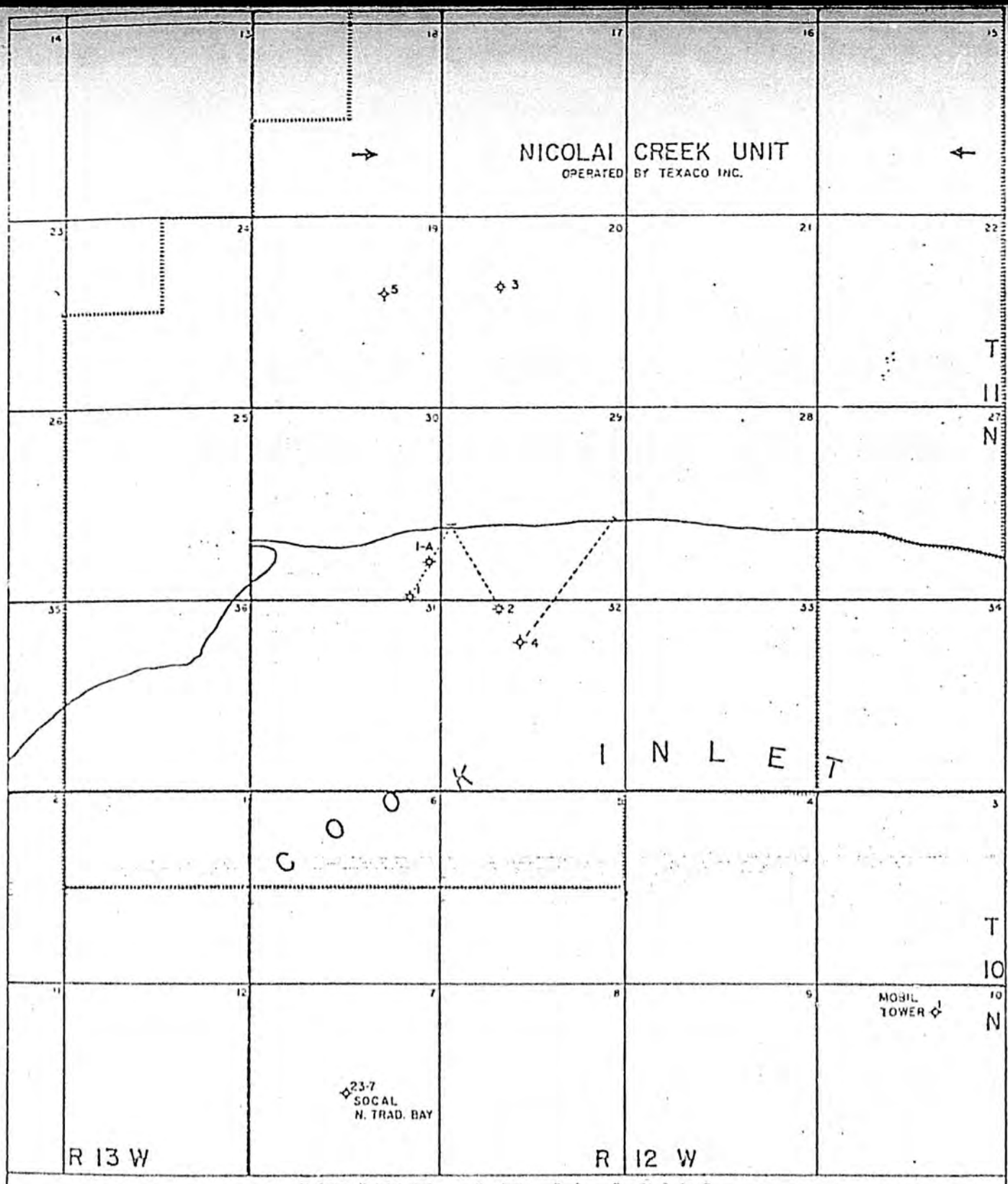
State royalty interest: 12.5%, 5% on non-producing lease

Gas sales (1974): 26 MCF/D gross

Possible inkind royalty: 4 MCF/D

General location - Westside Cook Inlet, see attached map.

AGO 570709



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

AGO 570710

NICOLAI CREEK FIELD

SCALE: 2,000' 0 2,000' 4,000' 8000'

APRIL 1, 1974

STERLING GAS FIELD

Operator: Union Oil Co.

Other participants: Marathon

Discovered: 1961

Production started: 1962

Number of wells (as of 2/75): 1 producing, 0 shut-in

Current producing rate (2/75): 3,810 MCF/month, 136 MCF/day

Estimated remaining reserves: 200,000 MMCF

Gas utilization: Heat greenhouse

Current wellhead value: $0.25/MCF

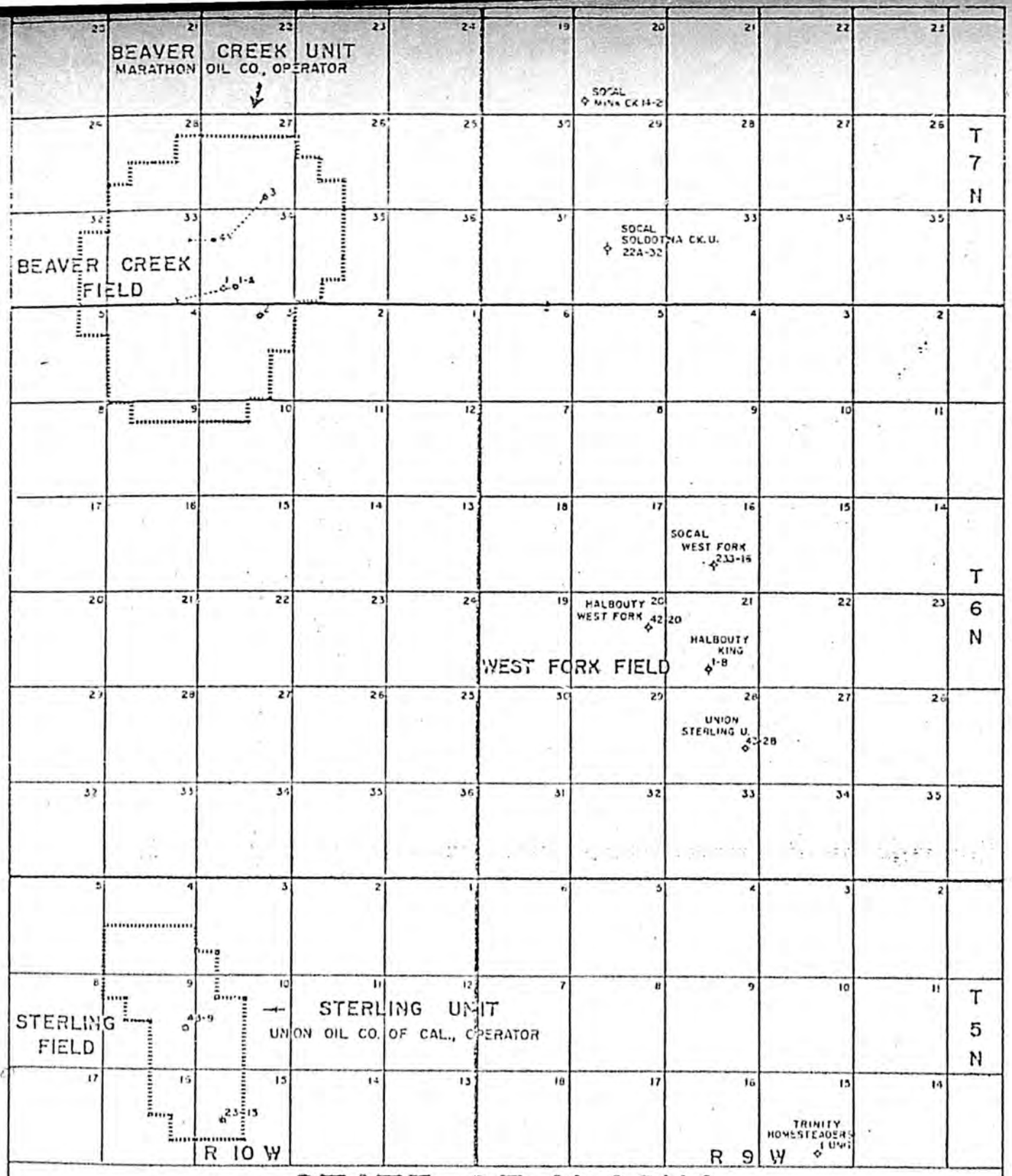
State royalty interest: 2.7224%

Gas sales (1974): 88 MCF/D

Possible inkind royalty: 2 MCF/D

General onshore location: Kenai, eastside Cook Inlet, see attached map.

Comments:
Available producing capacity is much greater than current sales, as shown in 1972 when gas was purchased by Consolidated Utilities to generate domestic electricity. All Sterling gas is now sold to heat a large greenhouse where vegetables are grown commercially.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

BEAVER CREEK, STERLING AND WEST FORK FIELDS

AGO 570712

SCALE: 4,000' 0 4,000' 8,000' 12,000'

APRIL 1, 1974

ALBERT KALOA GAS FIELD

Operator: Amoco

Other participants: Arco, Phillips and Skelly

Discovered: 1968

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 shut-in well

Current producing rate (2/75): No production

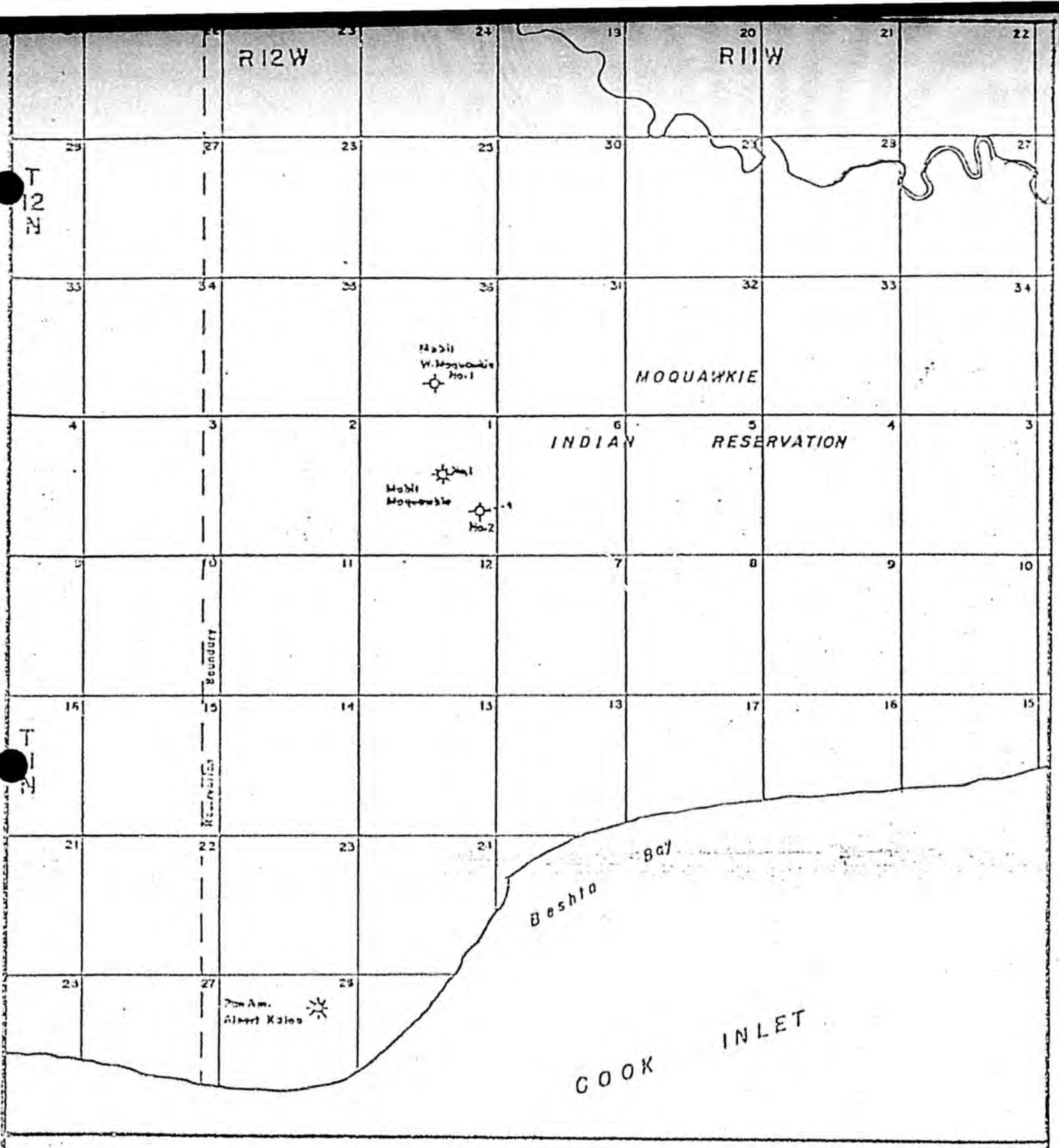
Estimated remaining reserves: Not known

Gas utilization: No production

State royalty interest: 0

General onshore location: Westside Cook Inlet, see attached map.

Comments:
This field has no pipeline connection but is close to the submarine pipeline to eastside Cook Inlet.



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS

AGO 570714

ANCHORAGE, ALASKA

ALBERT KOLOA and MOQUAWKIE FIELDS

Scale 1:63360

APRIL 1, 1974

BIRCH HILL GAS FIELD

Operator: Socal

Other participants: Arco, Union and Marathon

Discovered: 1965

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 well shut-in

Current producing rate (2/75): No production

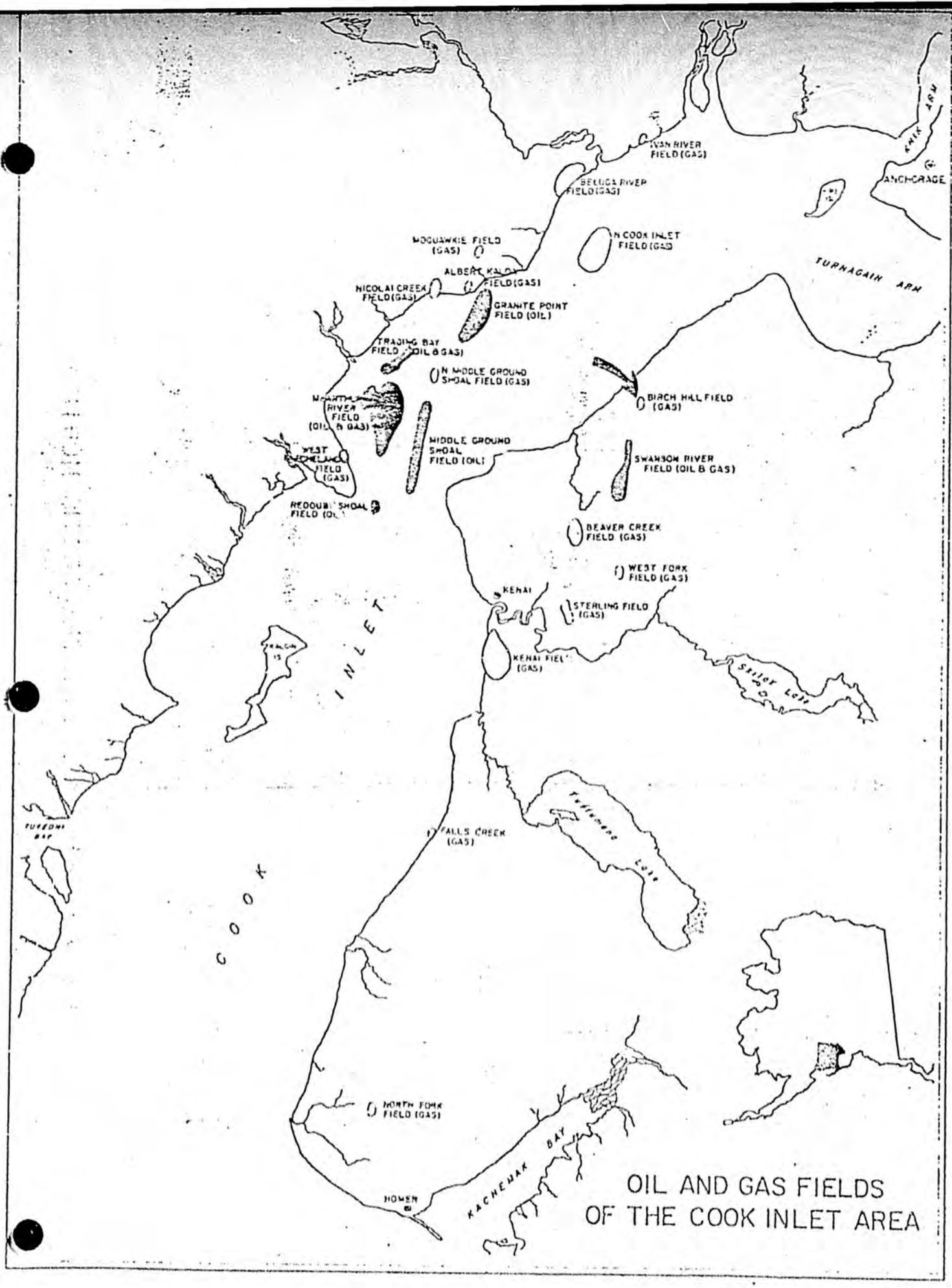
Estimated remaining reserves: 20,000 MMCF

Gas utilization: No production

State royalty interest: 0

General onshore location: Eastside Cook Inlet, see attached map.

Comments:
This semi-remote field is four miles north of Swanson River Oil and Gas Fields. The closest possible pipeline would be the 16" line from Kenai Field which transports rental gas for Swanson River Field reservoir pressure maintenance.


IVAN RIVER FIELD (GAS)
BELUGA RIVER FIELD (GAS)
KNIK ARM
ANCHORAGE
MOQUAWKIE FIELD (GAS)
N COOK INLET FIELD (GAS)
TURNAGAIN ARM
NICOLAI CREEK FIELD (GAS)
GRANITE POINT FIELD (OIL)
TRADING BAY FIELD (OIL & GAS)
N MIDDLE GROUND SHOAL FIELD (GAS)
BIRCH HILL FIELD (GAS)
MIDDLE GROUND SHOAL FIELD (OIL)
SWANSON RIVER FIELD (OIL & GAS)
BEAVER CREEK FIELD (GAS)
WEST FORK FIELD (GAS)
KENAI
STERLING FIELD (GAS)
KENAI FIELD (GAS)
COOK INLET
FALLS CREEK (GAS)
NORTH FORK FIELD (GAS)
KACHEMAK BAY
HOMER
OIL AND GAS FIELDS
OF THE COOK INLET AREA

AGO 570716

IVAN RIVER GAS FIELD

Operator: Socal

Other participants: Arco

Discovered: 1966

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 shut-in well

Current producing rate (2/75): No production

Estimated remaining reserves: 5,000 MMCF

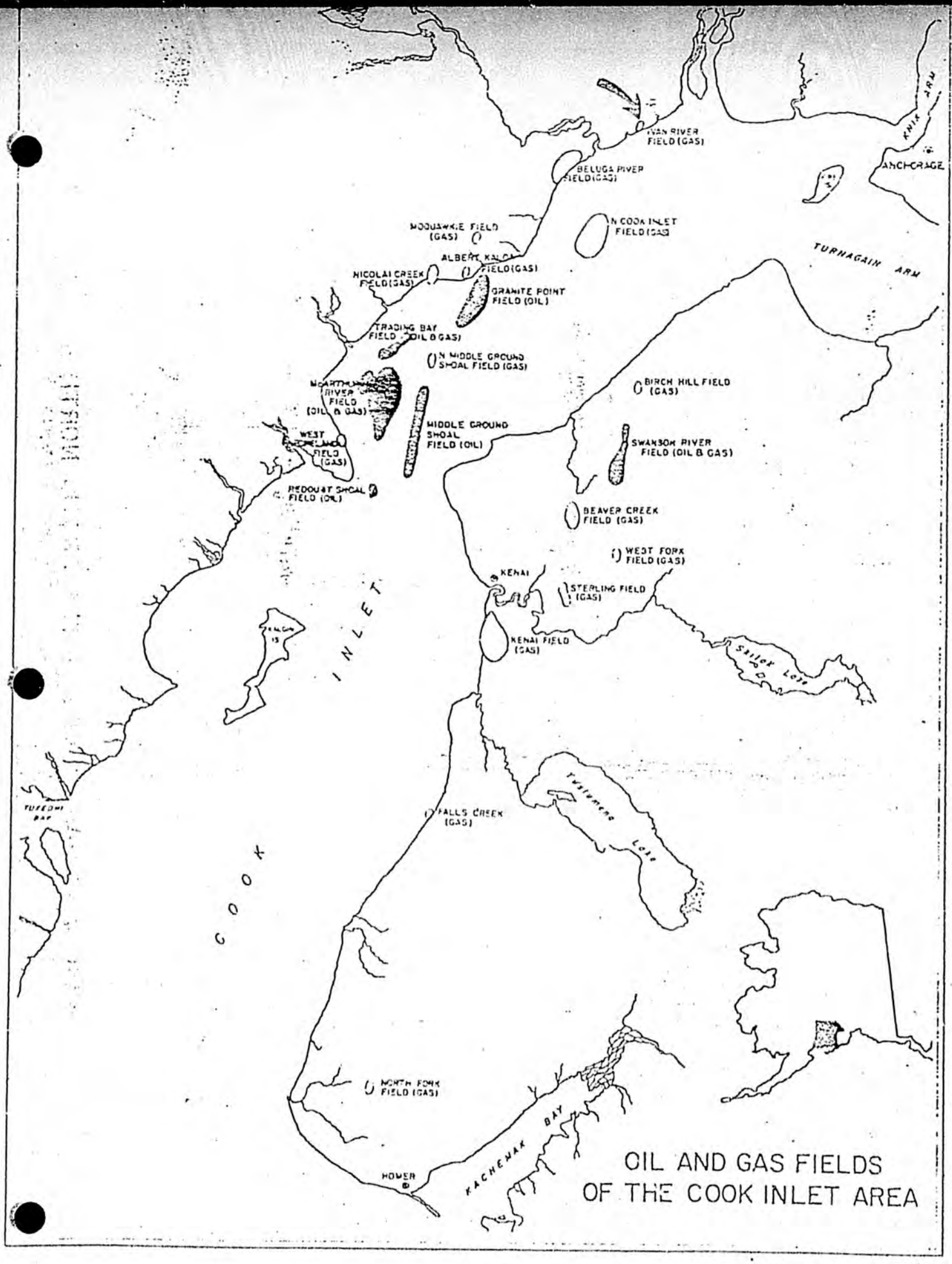
Gas utilization: No production

Misc.: One dry hole drilled within a mile

State royalty interest: 12.5%

General onshore location: Westside Cook Inlet, see attached map.

Comments:
This field is located approximately nine miles northeast of Beluga Gas Field which fuels electric generators supplying electricity to Anchorage through a 138 KV transmission line which runs three miles northwest of Ivan River Field. No pipelines are close to this field.


IVAN RIVER FIELD (GAS)
BELUGA RIVER FIELD (GAS)
KNIK ARM
ANCHORAGE
MOQUAWKIE FIELD (GAS)
N COOK INLET FIELD (GAS)
TURNAGAIN ARM
ALBERT KALOA FIELD (GAS)
NICOLAI CREEK FIELD (GAS)
GRANITE POINT FIELD (OIL)
TRADING BAY FIELD (OIL & GAS)
N MIDDLE GROUND SHOAL FIELD (GAS)
McARTHUR RIVER FIELD (OIL & GAS)
BIRCH HILL FIELD (GAS)
MIDDLE GROUND SHOAL FIELD (OIL)
WEST FORELAND FIELD (GAS)
SWANSON RIVER FIELD (OIL & GAS)
REDOUBT SHOAL FIELD (OIL)
BEAVER CREEK FIELD (GAS)
WEST FORK FIELD (GAS)
KENAI
STERLING FIELD (GAS)
KENAI FIELD (GAS)
COOK INLET
Tustumena Lake
TUXEDNI BAY
FALLS CREEK (GAS)
NORTH FORK FIELD (GAS)
KACHEMAK BAY
HOMER
OIL AND GAS FIELDS
OF THE COOK INLET AREA

AGO 570718

NORTH FORK GAS FIELD

Operator: Socal

Other participants: Arco, Sun Oil Co.

Discovered: 1965

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 shut-in well

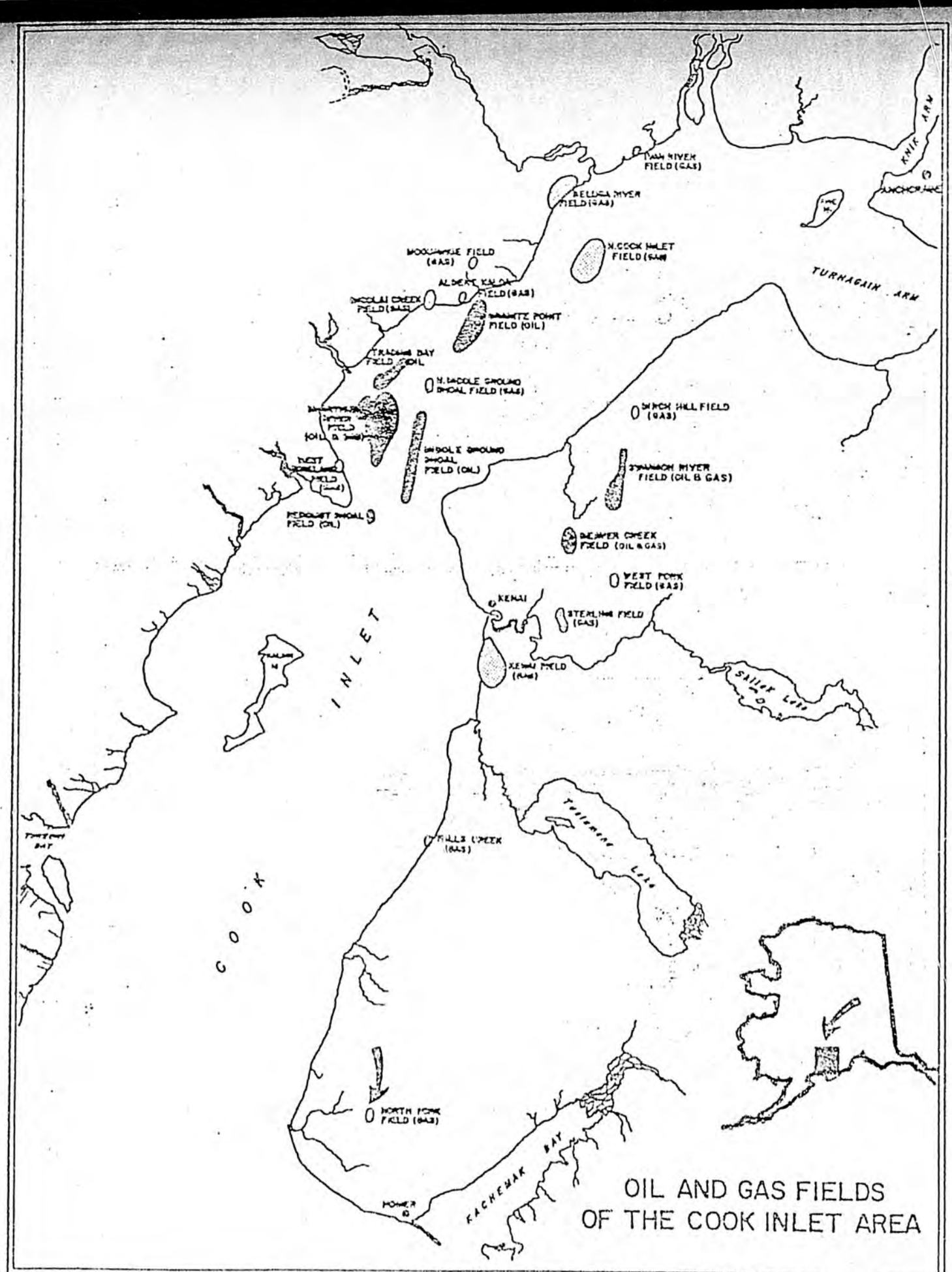
Current producing rate (2/75): No production

Estimated remaining reserves: 20,000 MMCF

Gas utilization: No production

General onshore location: Eastside Cook Inlet, see attached map.

Comments:
This semi-remote field is not near any existing gas pipelines.



OIL AND GAS FIELDS
OF THE COOK INLET AREA

AGO 570720

SWANSON RIVER GAS FIELD

Operator: Socal

Other participants: Arco, Union and Marathon

Discovered: 1957

Production started: 1960

Number of wells (as of 2/75): 6 shut-in wells

Current producing rate (2/75): No production

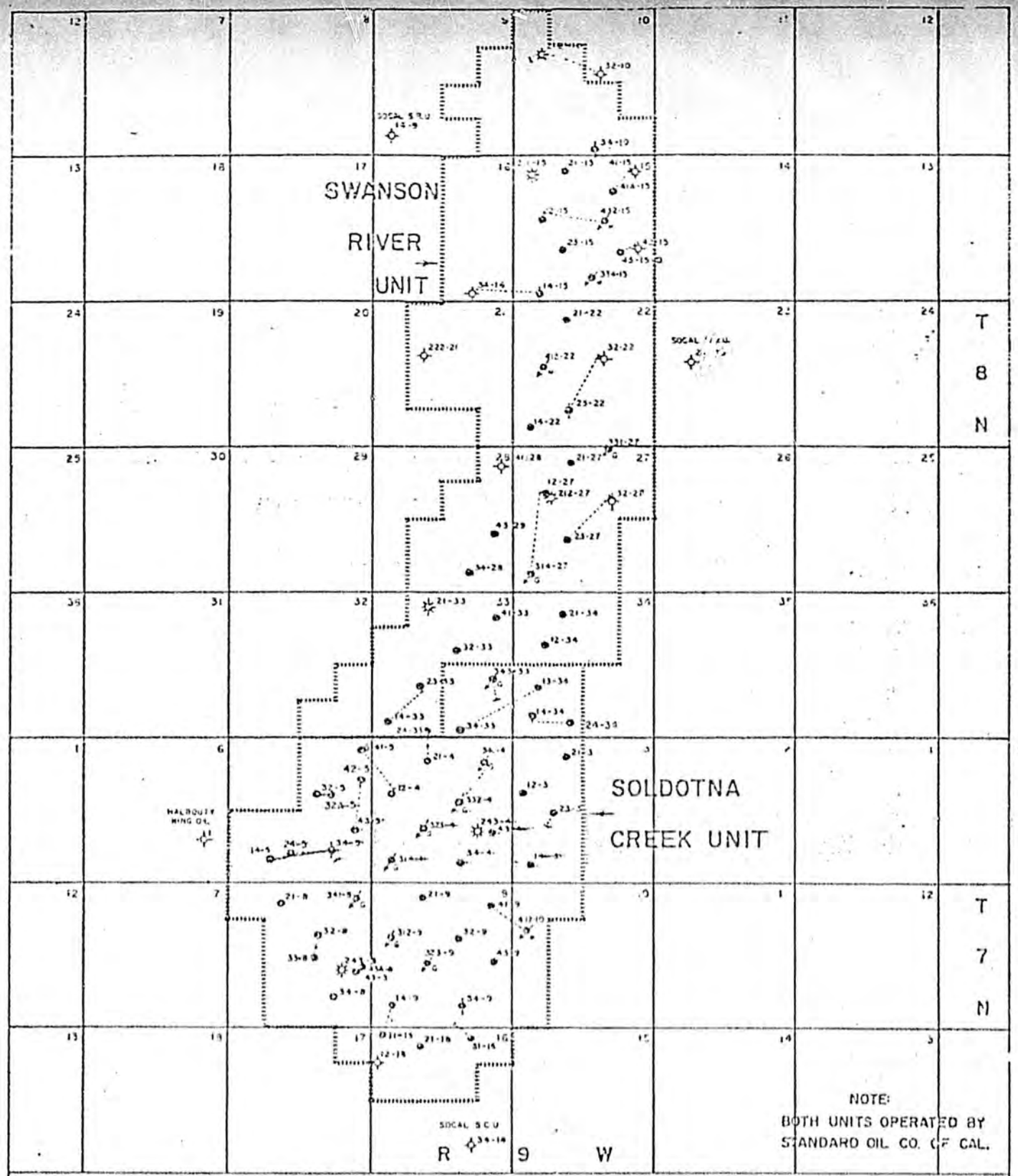
Estimated remaining reserves: 300,000 MMCF

Gas utilization: Produced gas was injected into Swanson River Oil Field until 1967. The field has been shut-in since that time.

State royalty interest: 0

General onshore location: Eastside Cook Inlet, see attached map.

Comments:
This field has no gas pipeline connection but could feed the Kenai Field system through the rental gas pipeline if it became available.



NOTE:
BOTH UNITS OPERATED BY
STANDARD OIL CO. OF CAL.

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

SWANSON RIVER FIELD

AGO 570722

SCALE: 1/2 mi 0 1/2 mi 1 mi 1 1/2 mi

APRIL 1, 1974

WEST FORELAND GAS FIELD

Operator: Amoco

Other participants: Arco, Phillips and Skelly

Discovered: 1962

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 shut-in well

Current producing rate (2/75): No production

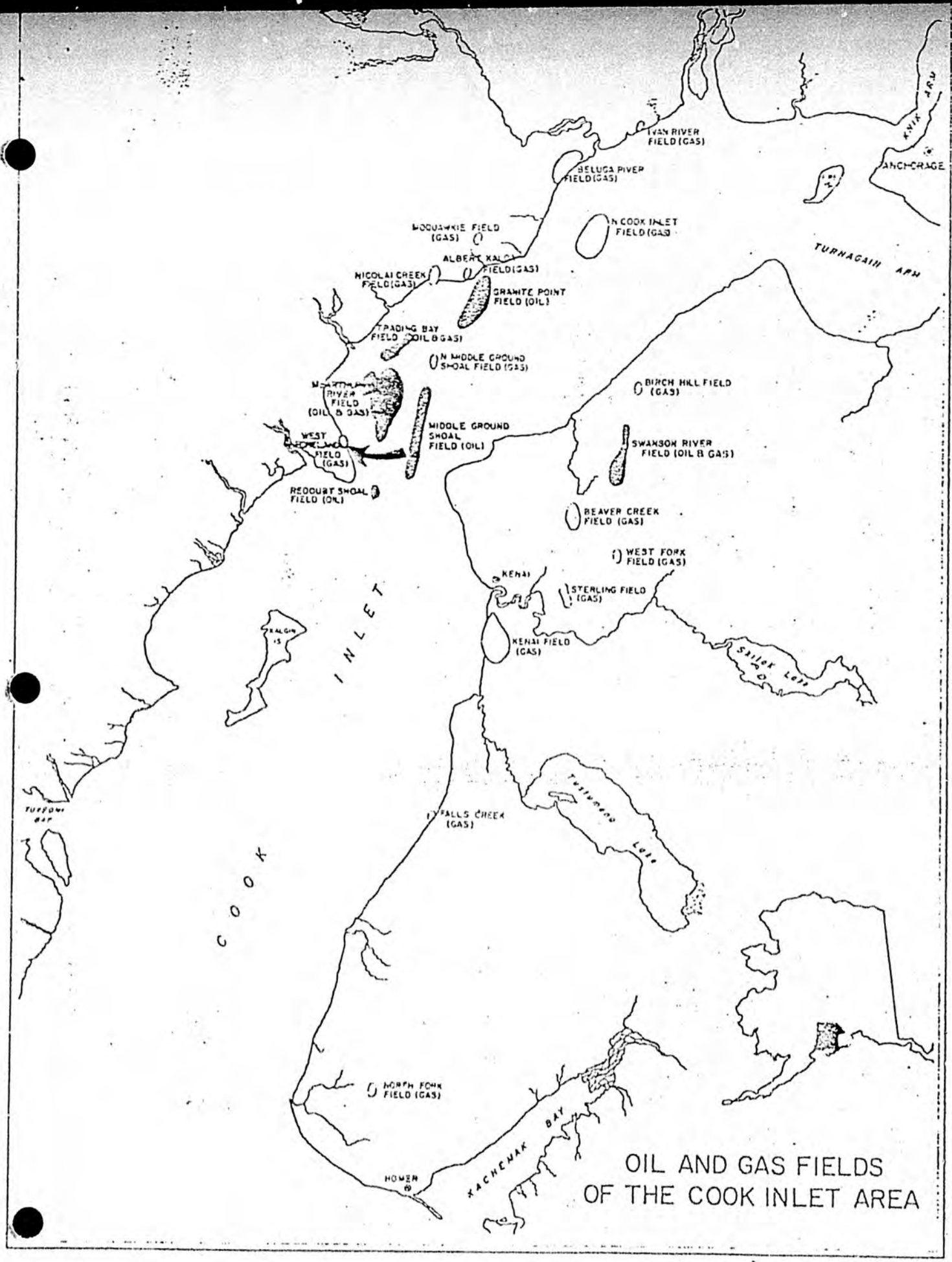
Estimated remaining reserves: 120,000 MMCF

Gas Utilization: No production

State royalty interest: 0

General onshore location: Westside Cook Inlet, see attached map.

Comments:
Gas from this semi-remote field could possibly be connected by pipeline to the existing submarine gas pipeline and moved to Nikiski, eastside Cook Inlet.



OIL AND GAS FIELDS OF THE COOK INLET AREA

AGO 570724

WEST FORK GAS FIELD

Operator: Socal

Other participants: Arco, Belco Pet. Co., Pet Corp. of Texas, Halbouty Alaska

Discovered: 1960

Production started: Field shut-in since discovery

Number of wells (as of 2/75): 1 shut-in well

Current producing rate (2/75); No production

Estimated remaining reserves: 100,000 MMCF

Gas utilization: No production

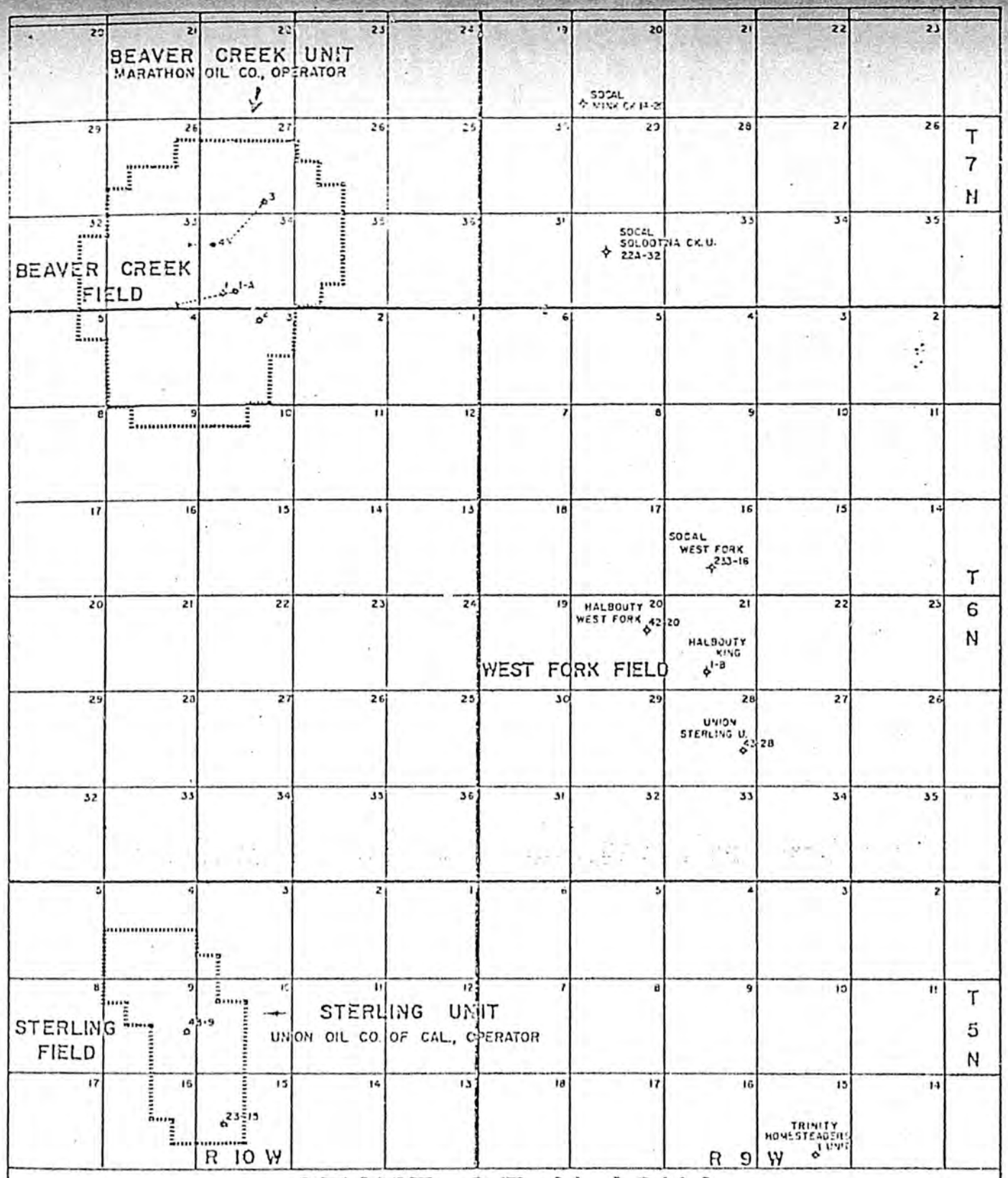
Misc.: This ultimately may be a one well field since three other wells drilled in this vicinity were dry holes.

State royalty interest: 0

General onshore location: Eastside Cook Inlet, see attached map.

Comments:
This semi-remote field is seven miles from the Sterling Gas Field pipeline.

AGO 570725



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

BEAVER CREEK, STERLING AND WEST FORK FIELDS

AGO 570726

SCALE: 4,000' 0 4,000' 8,000' 12,000'

APRIL 1, 1974

PRUDHOE BAY FIELD

Prudhoe Oil Pool

Proposed unit operators: Arco and BP

Other participants: Exxon Amerada, Getty, Hunt, Louisiana Land & Explor., Marathon, Mobil, Phillips, Placid, and Socal.

Discovered: 1967

Production started: 4/69, very small volumes for fuel requirements

Number of wells (as of 3/75): 2 producing, 97 shut-in

Current producing rate (2/75): Gas 225,165 MCF/month, 8042 MCF/day
oil (net) 46,209 bbl/month, 1650 B/D

Estimate of reserves by industry: Oil, approximately 9-1/2 billion bbls
Gas, approximately 26 trillion cu. ft.

Oil and gas utilization: Oil is run through topping plant to make arctic diesel and naptha. Gas is used to generate electrical power.

Current wellhead value: Gas, $.30/MCF, oil $2.07/BBL.

State royalty interest: 12-1/2%

Comments:
If the oil pipeline is completed on schedule, oil production could start from the Prudhoe Bay Oil Pool in July, 1977. The start of gas sales is more uncertain since the route for the gasline has not been selected yet. The earliest forecasted date for gas sales is 1980.

The following table shows the state royalty volumes of oil and gas from the Prudhoe Bay Oil Pool for a 5 year period on the following assumptions: (1) oil production begins in July, 1977 and will build up to a maximum rate of 1.7 million barrels per day at the end of the second year. (2) gas sales will begin in July, 1980 and will build up to a maximum rate of 2.6 billion cu. ft. per day in the second year.

Fiscal Year	78	79	80	81	82
Total oil production (million bbls.)	315	584	621	621	621
Total oil production (million barrels per day)	0.9	1.6	1.7	1.7	1.7
State royalty share (million bbls.)	39	73	78	78	78
State royalty share (million bbls. per day)	0.1	0.2	0.2	0.2	0.2
Total gas sales (billion cu.ft.)				708	967
Total gas sales (billion cu.ft. per day)				1.9	2.6
State's royalty share (billion cu.ft.)				88	121
State's royalty share (billion cu.ft. per day)				0.2	0.3

Lisburne Pool

The area and productivity of this pool have not been defined. Well information released to date has not been very encouraging. Arco recently tested their East Bay St. well in the Lisburne and reported a total rate from all intervals tested of only 1350 barrels of oil per day. Since this is a deep pool, approximately 11,000'; higher rates would probably be needed to be commercial. Further drilling will be required to determine if this pool has any significant reserves.

Kuparuk River Pool

Drilling on the west end of the Prudhoe Bay Field has indicated that the areal extent of the Kuparuk River Pool is larger than originally anticipated. Arco reported a test rate of 1030 barrels of oil per day from its West Sax #2 well. Since this is not a deep pool, approximately 6500', well rates as reported could be commercial. Additional drilling will be required to better define the area and productivity, indications are that this pool may have significant oil reserves.

OTHER NORTH SLOPE FIELDS

Oil

The Ugnu field and the Simpson Lagoon fields have 2 shut-in wells and one shut-in well respectively. These wells tested oil in the Kuparuk River sands. These fields could be just extensions of the Kuparuk River Pool of the Prudhoe Bay Field.

Gas

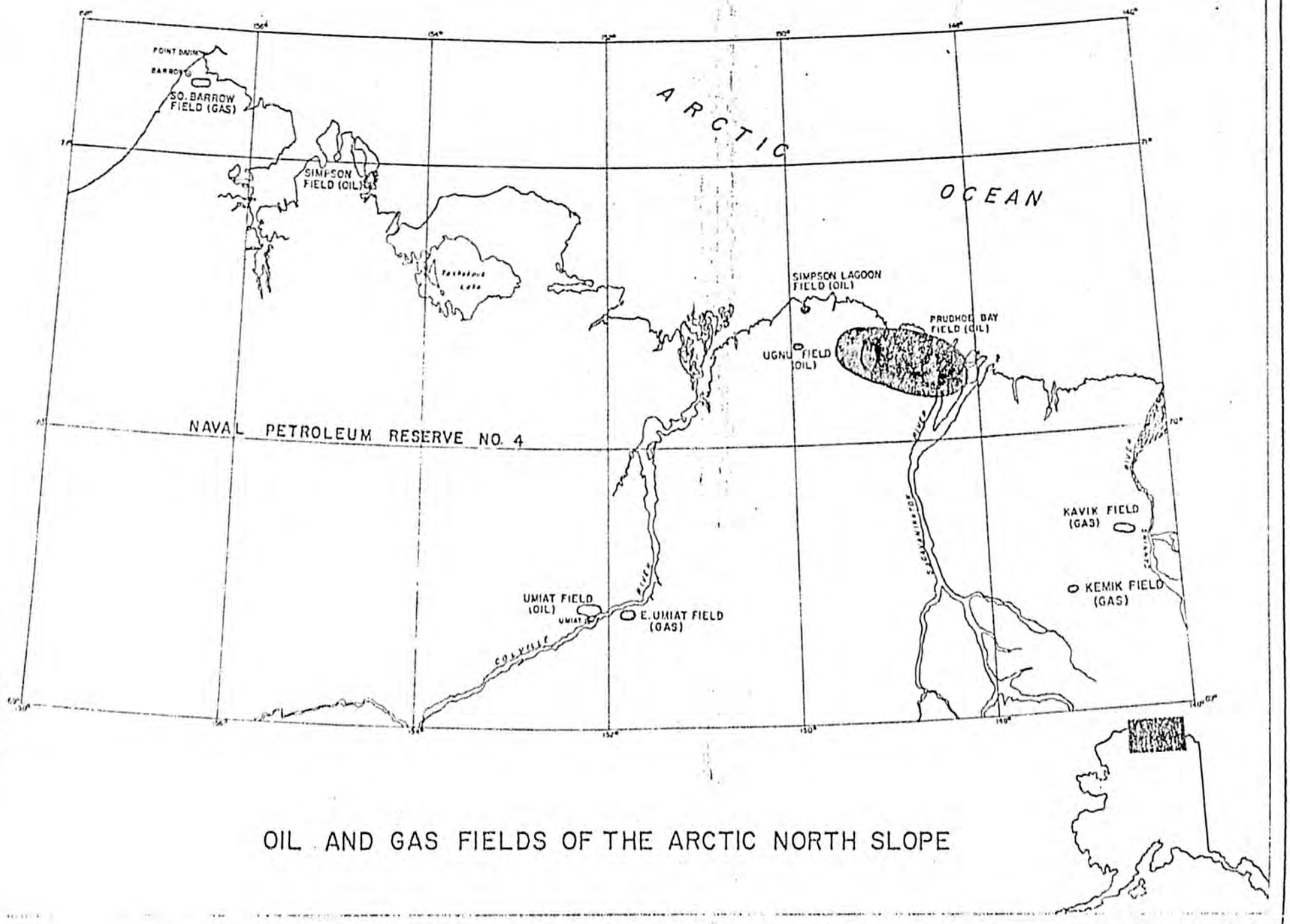
There are three small gas fields on the north slope, East Umiat with 2 shut-in wells, Kavik with 2 shut-in wells and Kemik with 1 shut-in well. The East Umiat and Kemik fields are on federal leases. The Kavik field is a unit on state leases. The unit size has been reduced and plans are to drill two additional wells for a total of four. This would complete the development of this small field.

Comments:
The oil and gas fields mentioned above as well as the Kuparuk River Pool and Lisburne Pool in the prudhoe Bay field have not been adequately defined and tested to determine their potential. The following forecast is actually the additional production, besides that predicted for the Prudhoe Bay Oil Pool, that is needed to fill the oil and gas pipelines. It assumes that this production will come from the miscellaneous fields and pool described or from new discoveries.

Fiscal Year	78	79	80	81	82
Total oil production (million bbls.)			18	55	146
Total oil production (million bbls. per day)			.05	.15	.25
State royalty share (million bbls.)			2	7	18
State royalty share (million bbls. per day)			.006	.02	.03
Total gas sales (billion cu.ft.)				22	36
Total gas sales (billion cu.ft. per day)				.06	.10
State royalty share (billion cu.ft.)				3	5
State royalty share (billion cu.ft. per day)				.008	.012

TOTAL PRUDHOE BAY FIELD & OTHER NORTH SLOPE FIELDS

Fiscal Year	78	79	80	81	82
Total oil production (million bbls.)	315	584	639	675	712
Total oil production (million bbls. per day)	0.9	1.6	1.75	1.85	1.95
State royalty share (million bbls.)	39	73	80	84	89
State royalty share (million bbls. per day)	0.11	0.20	0.22	0.23	0.24
Total gas sales (billion cu.ft.)				730	1004
Total gas sales (billion cu.ft. per day)				2.0	2.75
State royalty share (billion cu.ft.)				91	126
State royalty share (billion cu.ft. per day)				0.25	0.34



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OIL AND GAS FIELDS OF THE ARCTIC NORTH SLOPE

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PIPELINE AND LNG TRANSPORTATION SYSTEMS

FOR

COOK INLET GAS

Pacific Gas and Electric C
Southern California Gas Cc
February 14, 1978

AGO 544928 +

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F. Hood Corporation Appraisal

I. SUMMARY

The recent selection of the Alcan Highway Route for transportation of Alaskan North Slope gas has raised questions concerning the feasibility of moving Cook Inlet gas to the lower 48 states via pipeline across Central Alaska to the Alcan system. From this connection, Cook Inlet gas would flow south to Kingsgate, B.C. where connection would be made to the Pacific Gas Transmission Company (P.G.T.) portion of the Western Leg for transport to Malin, Oregon and then through Pacific Gas and Electric Company's system to Antioch, California. Several routes from the Cook Inlet area to a point of connection with this system were investigated in September, 1977, and cost estimates were prepared. A pipeline from Cook Inlet to Tok, on the Alcan Route, proved to be the most promising alternative.

On October 28, 1977, the FERC requested Pacific Alaska LNG Associates to provide a supplement to the "Alternatives to the Proposed Action" section of their environmental report. Specifically, FERC asked for information on possible pipeline route alternatives from Cook Inlet to the proposed Alcan Highway pipeline at Tok or Fairbanks.

This report summarizes estimated capital costs of these two alternatives and includes construction schedules and cost of service projections. All estimates are based on a 24" main line with an initial capacity of 431.4 million cubic feet per day. This volume is identical to that of the Pacific Alaska

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filing. All costs are in July, 1977 dollars.

Energy balances for both alternatives have been estimated and are compared with the energy balance for the Pac Alaska LNG project. The following are the points of comparison:

	Pac Alaska	Pipeline via Tok	Pipeline via Fairbanks
Efficiency (%)	88.1	82.1	81.3
Capital ($ MM)	1269	1154	1233
Cost of Delivered Gas ($/MMBtu)			
Incremental:			
1st Year	3.63	4.03	4.29
Level Annual	3.42	3.45	3.66
Average:			
1st Year	4.06	4.64	5.06
Level Annual	3.72	3.85	4.16

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II. DESCRIPTION OF ALTERNATES

Two cases are considered in this study (See Map - Exhibit A). Common to both are the Cook Inlet gathering systems, compressor stations at Beluga and Soldotna, 20" transmission lines from these stations to Palmer, and the Palmer compression station. From Palmer, Case I transports the gas in a 24" main line along Highway No.1 to a compressor station at Glennallen and then to Tok with a fifth station at Tok for delivery to the Alcan system. Case II provides for a 24" main line from Palmer generally following Highway No.3 with compressor stations at Curry, Lignite, and Fairbanks where connection to the Alcan line would be made.

Several assumptions have been necessary which undoubtedly will be changed by actual gas discoveries. These changes should have little effect on the capital cost and cost of service figures, however. For this initial study, the 431.4 million cubic feet per day capacity of the Pacific Alaska LNG project has been used as the basis for line and compressor sizing and cost of service calculations. Pacific Alaska's layout and cost estimates for gathering systems on both sides of Cook Inlet were also used with the exception that this pipeline plan provides for laterals on each side of the Inlet and eliminates the need for the 23-mile long underwater crossing required by the LNG project. Lacking firm data on location and deliverability of actual gas sources, it was further assumed that the two laterals would carry equal volumes of gas and that final design

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changes in pipeline sizes and compression requirements would balance out in the final cost estimate.

Flow calculations for the two cases are detailed in Exhibits E-1 and E-2.

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III. ENERGY BALANCES

Gas balances have been estimated for both pipeline alternatives as well as for the LNG project. Fuel usage from Cook Inlet to the points of delivery, Gosford, California for Pac Alaska and Antioch, California for the pipeline alternatives have been calculated and are detailed in Exhibits B-1, B-2, and B-3. The overall efficiency of the LNG project is about 6-7% higher than the pipeline alternatives' incremental efficiencies presented in the Exhibits. The pipeline alternatives' efficiencies are based on the incremental fuel necessary to transport the Cook Inlet gas when it is transported on top of Prudhoe Bay and Mackenzie Delta Gas.

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IV. CAPITAL COSTS

Capital cost figures have been developed for Cook Inlet to Alcan and Western Leg segments of the proposed system using, wherever possible, firm quotations from suppliers and contractors. In this phase of the study, however, it has been necessary to make assumptions on construction methods and unit costs on some portions of the work. Where this has been done, the effort has been made to estimate costs on the conservative side. For example, total costs include refrigeration of the gas to 30°F and insulation of the entire pipeline. In final design, it may well be that this will prove redundant. Bases for the major cost items are:

Construction - Hood Corporation was retained to inspect and determine the feasibility of the proposed routes, and to prepare installation estimates and construction schedules. Exhibit F is a statement of their assessment of the project.

Pipeline Materials - Price quotations were obtained by Southern California Gas Company's purchasing department from domestic suppliers for pipe, valves, and insulation. All pipe was quoted as double-jointed and wrapped, F.O.B., Seattle. Transportation to the job sites is included in the Hood estimate. Ten mile spacing of main line valves was used with three main valves at compressor stations and valves at both sides of the Turnagain Arm underwater crossing.

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Gathering Systems - Costs developed by Pacific Alaska LNG Associates (Docket No. CP75-140, et al, Exhibit No. _____ MEF-12) were amended to eliminate the 23-mile Cook Inlet crossing. Pipeline systems on both sides of the inlet were retained with connection assumed to be made at compressor stations located at Beluga and Soldotna.

Capital cost estimates are itemized in Exhibits C-1 through C-5.

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V. COST OF SERVICE

Cost of service figures have been developed for delivery of Cook Inlet gas to California using the following data:

- Cook Inlet to Alcan: Southern California Gas Company capital cost extimates, Exhibits C-1 and C-2.

- Alcan System: to Kingsgate, B.C. Southern California Gas Company estimates based on Alcan Pipeline Company, March, 1977 FPC filing. Average cost of service for Prudhoe gas was used prorated on a mileage basis. Incremental cost of service for Prudhoe plus Cook Inlet gas based on PGandE estimates.

- P.G.T. System: Kingsgate-Malin, Ore. P.G.T. estimates for 592 miles of 42" - 911 psig pipeline looping with 4-14100 HP compression units. Incremental cost for Prudhoe plus Cook Inlet gas.

- PG&E System: Malin-Antioch, CA. PG&E estimate for 281.6 miles of 42" - 911 psig pipeline looping with 2-14100 HP compression units. Incremental cost for Prudhoe plus Cook Inlet gas.

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Other assumptions used in the calculations were:

	Debt/Equity	Return on Equity	Debt Interest
Pac Alaska	75/25	16%	10%
Cook Inlet to Alcan Pipelines	75/25	16%	10%
P.G.T.-Kingsgate to Malin	75/25	16%	10%
PGandE-Malin to Antioch	75/25	16%	10%

Cost of Services Estimates for both the first year of full delivery and on a level annual cost basis over the project life are tabulated in Exhibits D-1 through D-6.

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VI. CONSTRUCTION

Project completion date is assumed to be first quarter 1983 to agree with estimated completion of the Alcan System. Actual construction time for either the Tok or Fairbanks alternate is estimated to be 18 months. Soil conditions are expected to limit construction of the gathering systems and Beluga and Soldotna laterals to the winter months. Work on the main lines from Palmer to Alcan is expected to be possible year-round. Thus, construction would start in the fall of 1981, and be completed in spring 1983 with two winter construction periods available for the Cook Inlet work. Hood Corporation has estimated that the work would be organized in the following manner:

	Miles	Crew Size	# of Spreads	Pipeline Inst. Time	Project Duration
East Side Cook Inlet					
Soldotna-Turnagain Arm	60	190	1	5 mo.	7 mo.
Turnagain Arm Crossing	5	160	1	2 mo.	4 mo.
Turnagain Arm-Palmer	43	190	1	4 mo.	6 mo.
West Side Cook Inlet					
Beluga-Palmer	84	260	2	4 mo.	6 mo.
Main Line					
Palmer-Tok	267	750	3	6 mo.	8 mo.
or					
Palmer-Fairbanks	314	750	3	7 mo.	9 mo.
Gathering Systems					
Indefinite but based on previous estimates of laterals extending to Anchor Point and Drift River on the order of:					
East Side Cook Inlet	--	190	1	5 mo.	7 mo.
West Side Cook Inlet	--	260	1	7 mo.	9 mo.

Other conditions considered in the study are 100% x-ray of all welds and the use of existing power line and/or highway rights-of-way.

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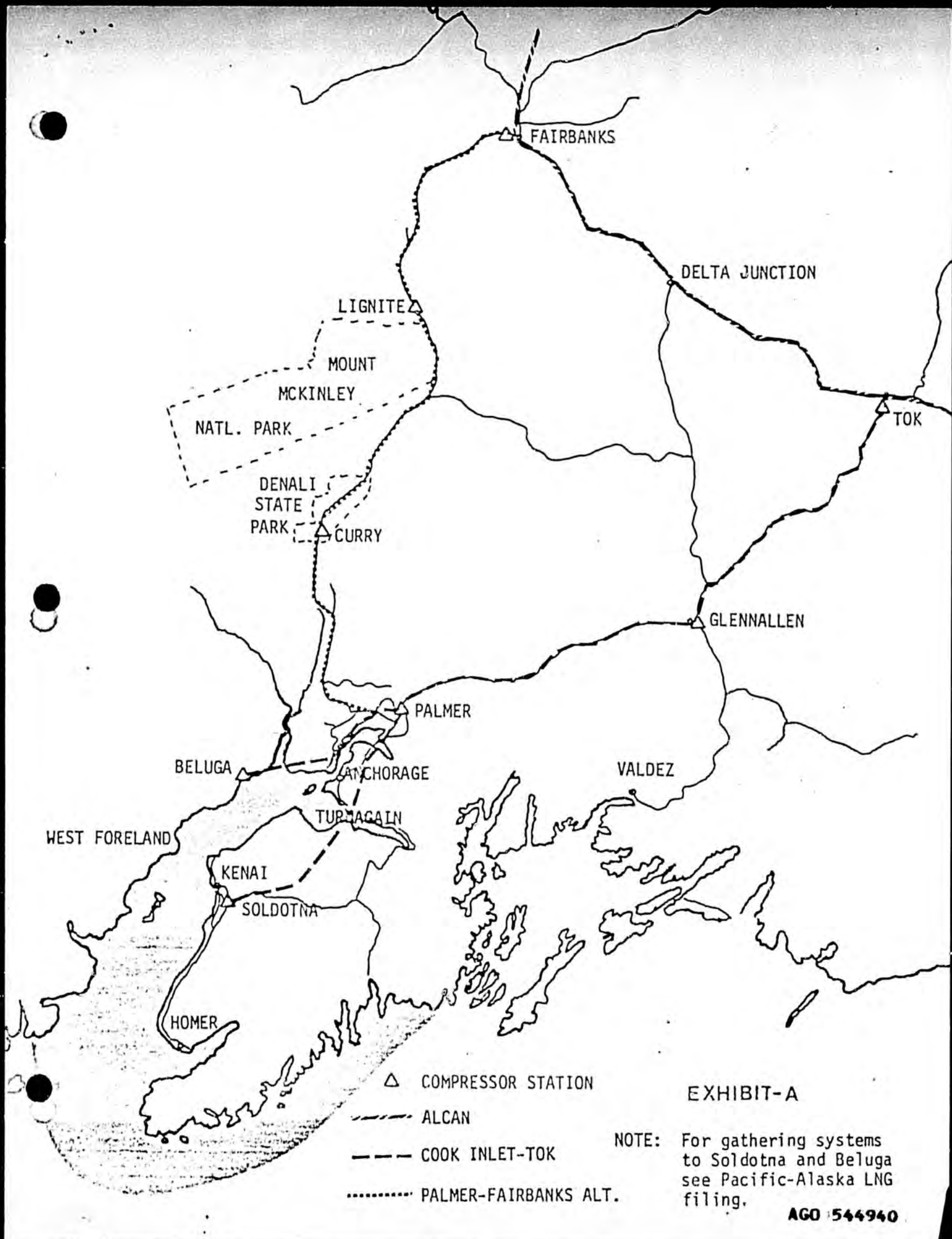

EXHIBIT-A

NOTE: For gathering systems to Soldotna and Beluga see Pacific-Alaska LNG filing.

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PAC ALASKA

GAS BALANCE
(Millions of cubic feet per day) (1)

Cook Inlet Input		442.8
Fuel		
LNG Plant	39.3	
LNG Shipping (2)	3.3	
LNG Terminal	0.2	
Total Fuel	42.8	
Delivery to Gosford		400
Pac Alaska Efficiency (2)		90.3%

(1) All gas volumes adjusted to 1014 Btu/cf heating value.
(2) If Bunker "c" fuel oil consumption of 10.1 mmcf/d gas equivalent is included, efficiency is reduced to 88.1%.

Exhibit B-1

PIPELINE ALTERNATIVE VIA TOK

GAS BALANCE

(Million cubic feet per day) (1)

Cook Inlet Input		431.4
Fuel (2)		
Cook Inlet to Tok	9.0	
Tok to Caroline	50.7	
Caroline to Kingsgate	2.5	
Kingsgate to Malin	10.8	
Malin to Antioch	4.2	
Total Fuel	77.2	
Delivery to Antioch		354.2
Pipeline Efficiency		82.1%

(1) All gas volumes adjusted to 1014 Btu/cf heating value.
(2) Incremental fuel to transport Cook Inlet gas in addition to Prudhoe (2.4 Bcf/d) and Delta (1.2 Bcf/d) gas.

Exhibit B-2

PIPELINE ALTERNATIVE VIA FAIRBANKS
GAS BALANCE
(million cubic feet per day) (1)

Cook Inlet Input		431.4
Fuel (2)		
Cook Inlet to Fairbanks	8.9	
Fairbanks to Tok	3.4	
Tok to Caroline	50.7	
Caroline to Kingsgate	2.5	
Kingsgate to Malin	10.8	
Malin to Antioch	4.2	
Total Fuel	80.5	
Delivery to Antioch		350.9
Pipeline Efficiency		81.3%

(1) All gas volumes adjusted to 1014 Btu/cf heating value.

(2) Incremental fuel to transport Cook Inlet gas in addition to Prudhoe (2.4 Bcf/d) and Delta (1.2 Bcf/d) gas.

Exhibit B-3

COOK INLET TO TOK PIPELINE

CAPITAL COST ESTIMATE - 1977 $

(Thousands of Dollars)

	Materials	Construction	Total
Pipeline	$ 79,690	$247,494	$327,184
Valves, Fittings, Misc.	8,679	4,575	13,254
Insulation	39,816	19,340	59,156
Compression	28,000	12,750	40,750
Refrigeration	12,280	5,590	17,870
Anchors	820	1,640	2,460
Controls	6,515	13,030	19,545
X-Ray	--	8,845	8,845
	$175,800	$313,264	$489,064
Sales Taxes	10,080	--	10,080
Total Pipeline Direct	$185,880	$313,264	$499,144
Right-of-Way			$ 11,641
R/W Restoration			9,300
E.I.R			2,815
Engineering			26,310
Contingency			71,497
Working Capital			588
AFUDC			64,073
Financing Fee			2,522
Materials & Supplies			6,210
Total Project			$694,100

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Exhibit C-1

COOK INLET TO FAIRBANKS PIPELINE

CAPITAL COST ESTIMATE - 1977 $

(Thousands of Dollars)

	Materials	Construction	Total
Pipeline	$ 86,130	$267,474	$353,604
Valves, Fittings, Misc.	8,914	4,581	13,495
Insulation	44,331	21,274	65,605
Compression	28,000	12,750	40,750
Refrigeration	12,280	5,590	17,870
Anchors	820	1,640	2,460
Controls	6,515	14,350	20,865
X-Ray	--	9,832	9,832
	$186,990	$337,491	$524,481
Sales Taxes	10,751	--	10,751
Total Pipeline Direct	$197,741	$337,491	$535,232

Right-of-Way	$ 12,192
R/W Restoration	10,220
E.I.R.	3,061
Engineering	28,115
Contingency	76,910
Working Capital	588
AFUDC	68,721
Financing Fee	2,704
Materials & Supplies	6,657
Total Project	$744,400

Exhibit C-2

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PAC ALASKA LNG

CAPITAL INVESTMENT SUMMARY - 1977$
(Millions of Dollars)

Pac Alaska LNG	Phase I	Phase II	Total
Gas Gathering	168	32	200
Liquefaction Plant	496	154	650
Ships	197	197	394
Terminal	25	-	25
Total	886	383	1269

Exhibit C-3

PIPELINE ALTERNATIVE VIA TOK

CAPITAL INVESTMENT SUMMARY - 1977 $

(MILLIONS OF DOLLARS)

	Base[1] Design	Base Plus Cook	Cook Incremental
Cook to Tok	0	694	694
Tok to Kingsgate	-	-	150
Kingsgate to Malin	367	590	223
Malin to Antioch	205	292	87
TOTAL[2]	-	-	1154

(1) Base Design is for a system to transport Prudhoe plus Mackenzie Delta Gas.

(2) Modifications to existing natural gas system will be needed south of Antioch. Such modifications may add as much as an additional $126 million (1977 $) investment to the Cook Incremental.

AGO 544947

PIPELINE ALTERNATIVE VIA FAIRBANKS

CAPITAL INVESTMENT SUMMARY - 1977 $

(MILLIONS OF DOLLARS)

	Base[1] Design	Base Plus Cook	Cook Incrementa
Cook to Fairbanks	0	744	744
Fairbanks to Kingsgate	-	-	179
Kingsgate to Malin	367	590	223
Malin to Antioch	205	292	87
TOTAL[2]	-	-	1233

(1) Base Design is for a system to transport Prudhoe plus Mackenzie Delta Gas.

(2) Modifications to existing natural gas system will be needed south of Antioch. Such modifications may add as much as an additional $126 million (1977 $) investment to the Cook Incremental.

Exhibit C-5

PAC ALASKA

INCREMENTAL COST OF GAS SUMMARY

(1977 $/MMBTU)

Pac Alaska	1982 Phase I	1983 Phase I & II	Level Annual
Purchased Natural Gas	1.64	1.64	1.64
Gathering & Liquefaction Plant	2.25	1.29	1.18
Shipping	.61	.62	.52
Terminal (Incremental)	.16	.08	.08
Delivered Price of Gas (Incremental)	4.66	3.63	3.42
Price of Pac Indonesia at Incremental Cost	4.72	3.74	3.45

Exhibit D-1

PAC ALASKA

COST OF GAS SUMMARY SUBSTITUTING AVERAGE TERMINAL AND TERMINAL PIPELINE COSTS

(1977 $/MMBTU)

Pac Alaska	1982 Phase I	1983 Phase I & II	Level Annual
Purchased Natural Gas (Incremental)	1.64	1.64	1.64
Gathering & Liquefaction Plant (Incremental)	2.25	1.29	1.18
Shipping (Incremental)	.61	.62	.52
Terminal (Average)	.93	.46	.34
Terminal Pipeline (Average)	.08	.05	.04
Delivered Price of Gas at Average Cost of California Facilities	5.51	4.06	3.72
Price of Pac Indonesia at Average Terminal Cost	4.04	3.36	3.25

PIPELINE ALTERNATIVE VIA TOK

INCREMENTAL COST OF GAS SUMMARY

(1977 $/MMBTU)

	1983	Level Annual
Purchase of Natural Gas	1.80	1.80
Pipeline Segments		
Cook to Tok	1.28	.92
Tok to Kingsgate	.41	.33
Kingsgate to Malin	.39	.29
Malin to Antioch	.15	.11
TOTAL DELIVERED TO ANTIOCH(1)	4.03	3.45

(1) Modification to existing natural gas system will be needed south of Antioch. Such modification may add as much as an additional 20¢ to 30¢ per million Btu (1977 $).

PIPELINE ALTERNATIVE VIA TOK

COST OF GAS SUMMARY
SUBSTITUTING AVERAGE COST FOR
INCREMENTAL COST FOR TOK TO KINGSGATE

(1977 $/MMBTU)

	1983	Level Annual
Purchase of Natural Gas	1.80	1.80
Pipeline Segments		
Cook to Tok	1.28	.92
Tok to Kingsgate[1]	1.02	.73
Kingsgate to Malin	.39	.29
Malin to Antioch	.15	.11
TOTAL DELIVERED TO ANTIOCH[2]	4.64	3.85

(1) Based on Alcan Pipeline Company, March, 1977 FPC filing. Redesign of Alcan system may reduce this average cost slightly.

(2) Modification to existing natural gas system will be needed south of Antioch. Such modification may add as much as an additional 20¢ to 30¢ per million Btu (1977 $).

PIPELINE ALTERNATIVE VIA FAIRBANKS

INCREMENTAL COST OF GAS SUMMARY

(1977 $/MMBTU)

	1983	Level Annual
Purchase of Natural Gas	1.84	1.84
Pipeline Segments		
Cook to Fairbanks	1.41	1.01
Fairbanks to Kingsgate	.48	.39
Kingsgate to Malin	.40	.30
Malin to Antioch	.16	.12
TOTAL DELIVERED TO ANTIOCH(1)	4.29	3.66

(1) Modification to existing natural gas system will be needed south of Antioch. Such modification may add as much as an additional 20¢ to 30¢ per million Btu (1977 $).

PIPELINE ALTERNATIVE VIA FAIRBANKS

COST OF GAS SUMMARY
SUBSTITUTING AVERAGE COST FOR INCREMENTAL COST FOR FAIRBANKS TO KINGSGATE
(1977 $/MMBTU)

	1983	Level Annual
Purchase of Natural Gas	1.84	1.84
Pipeline Segments		
Cook to Fairbanks	1.41	1.01
Fairbanks to Kingsgate[1]	1.25	.89
Kingsgate to Malin	.40	.30
Malin to Antioch	.16	.12
TOTAL DELIVERED TO ANTIOCH[2]	5.06	4.16

(1) Based on Alcan Pipeline Company, March, 1977 FPC filing. Redesign of Alcan system may reduce this average cost slightly.

(2) Modification to existing natural gas system will be needed south of Antioch. Such modification may add as much as an additional 20¢ to 30¢ per million Btu (1977 $).

Exhibit D-6

ASSUMPTIONS USED IN COST OF SERVICE AND CAPITAL COST COMPARISONS

Cook Inlet to Tok
Cook Inlet to Fairbanks

1. Construction costs, fuel usage, operating and maintenance estimated by Southern California Gas Company. AFUDC cost computed.
2. 75% debt at 10% interest and 25% equity at 16% return.
3. 20-year project life.
4. 2% property tax rate.
5. 52.89% composite federal and state income taxes.
6. Fuel included in cost of purchased gas.
7. Annual Btu volume based on delivered volume as shown in energy balance.
8. Used normalized method to compute cost of service.

Tok to Kingsgate
Fairbanks to Kingsgate

1. Based on cost of service figures from Exhibit 7-1, page 1 of 2 of Alcan's filing of March 1977 for 48" alternative.
2. Used 10% of Alcan's Alaskan cost of service for Tok alternate since distance from Tok to Yukon is approximately 75 miles or 10% of a total of 731 miles from Prudhoe to Yukon. Used 38% for Fairbanks costs since distance from Fairbanks is approximately 280 miles or 38% of a total distance of 731 miles.
3. Used 100% of the remaining cost of service figures excluding PGT and PG&E.
4. Increased cost of service figures by 30% for probable cost overruns per President Carter's Message to Congress.
5. Inflated cost of service derived above by an additional 8% compounded annually to obtain 1977 $ from 1975 $.
6. Fuel cost left at $1.00/MMBTU per the Alcan Pipeline Company filing of March 1977 for 48" alternative.

(Continued)

Kingsgate to Malin

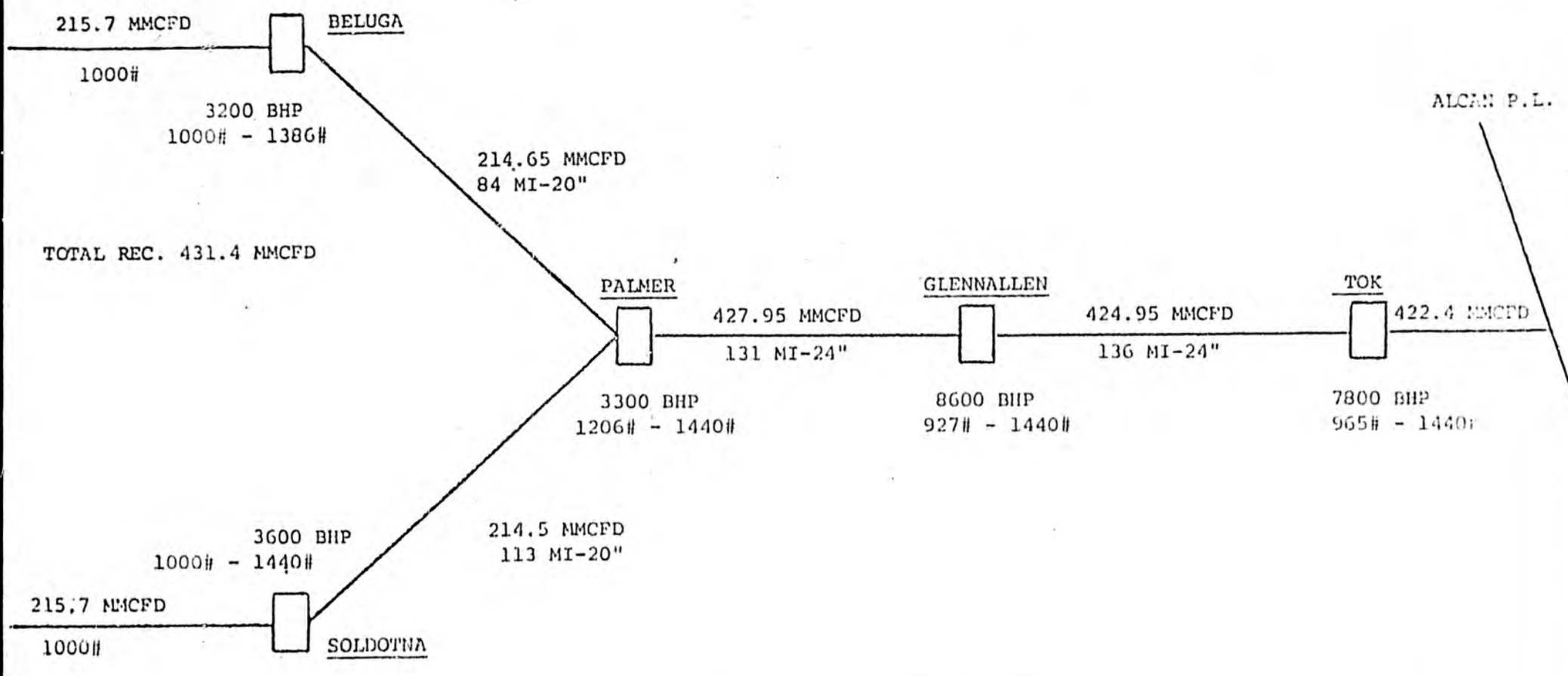
1. Construction costs, fuel usage, operating and maintenance and AFUDC from P.G.T.
2. 75% debt at 10% interest and 25% equity at 16% return.
3. 20-year project life.
4. 1.5% property tax rate.
5. 52% composite federal and state income taxes.
6. Fuel included in cost of purchased gas.
7. Annual BTU volume based on delivered volume as shown in energy balance.
8. Used normalized method to compute cost of service.

Malin to Antioch

1. Construction costs, fuel usage, operating and maintenance and AFUDC from PG&E.
2. 75% debt at 10% interest, 25% common equity at 16% return.
3. 20-year project life.
4. 1.75% property tax rate.
5. 52.68% composite federal and state income taxes.
6. Fuel included in cost of purchased gas.
7. Annual BTU volume based on delivered volume as shown in energy balance.

Purchase Natural Gas Costs

Purchase Natural Gas costs for both the LNG and Pipeline alternatives reflect the $1.46/MMBtu field price assumed for both projects adjusted to reflect the respective overall system gas balance efficiency of each project.

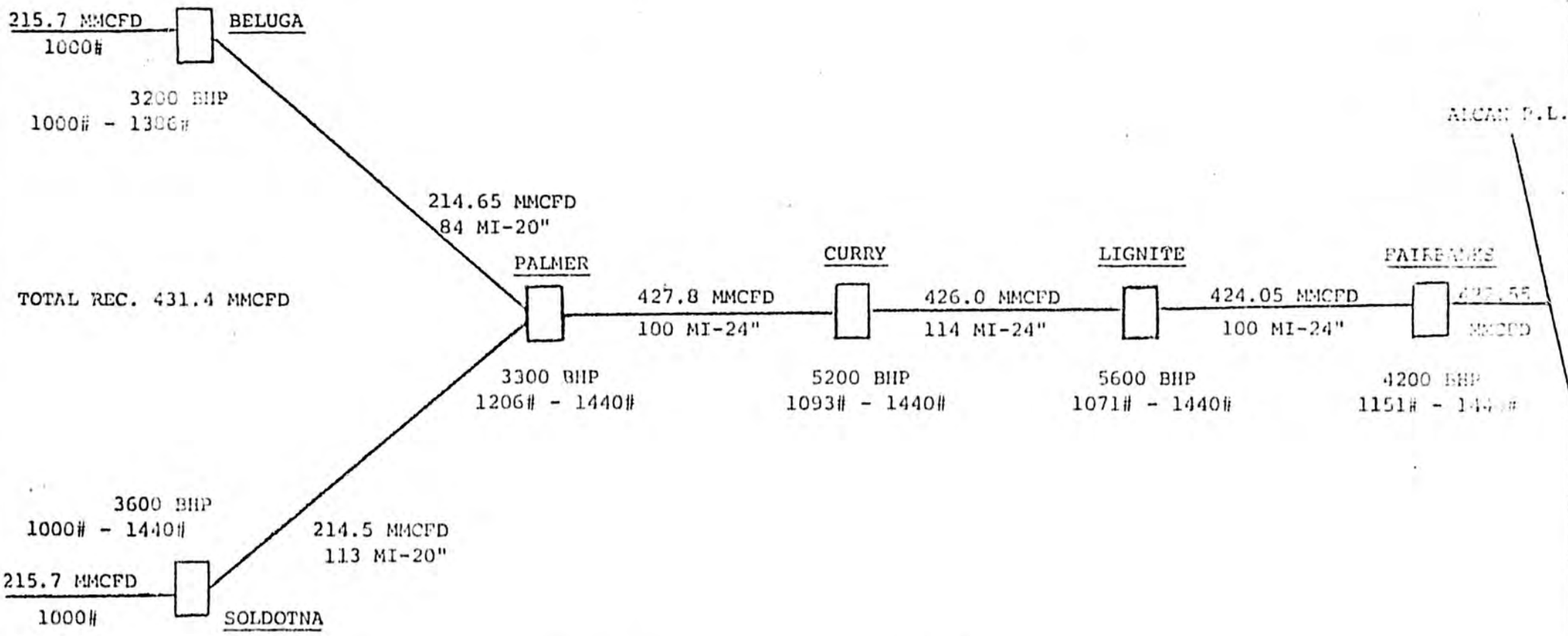


PIPELINE: X-65 t = 30°F
1440# MAOP S.G. = 0.60
CLASS I EFF. = 85%

EXHIBIT E-1

FLOW CALCULATIONS-COOK INLET TO TOK

AGO 544957



PIPELINE: X-65 t = 30°F
1440 MAOP S. G. = 0.60
CLASS I EFF. = 85%

EXHIBIT E-2

FLOW CALCULATIONS-COOK INLET TO FAIRBANKS

AGO 544958

Southern California Gas Company
Alaska Gas Pipeline Study
Possible Route Selection and Description

In November of 1977, Hood Corporation was engaged by the Southern California Gas Company to examine possible gas pipeline routes from Anchor Point, Alaska on the east side of Cook Inlet and Drift River on the west side of Cook Inlet, north to Palmer and then on northerly to a possible tie-in point on the proposed Alcan Natural Gas Pipeline at either Fairbanks, Delta Junction or Tok Junction.

Six different cost of field construction alternates were prepared and submitted to the Gas Company utilizing various pipeline sizes and final tie-in points to the Alcan line. The proposed right-of-way for all cases studied was identical from Drift River and Anchor Point to Palmer. At Palmer the Fairbanks alternate would follow north along Highway 3 to Fairbanks while the Delta Junction and Tok Junction alternates would be routed easterly to Glennallen along Highway #1 and either follow Highway 4 northerly to Delta Junction or continue along Highway 1 to Tok Junction.

Route determination was accomplished by utilizing topographic maps of the Alaska topographic series prepared by the United States Department of the Interior Geological Survey. Topographic or physical features not shown or noted on the U.S.G.S. maps were confirmed by visual inspection while flying the proposed pipeline routes in a Bell Jet Ranger Helicopter.

A generalized description of the terrain to be encountered and existing rights-of-way on each leg of the proposed right-of-way is described below.

Drift River to Beluga (63 Miles)
(Kenai and Tyonek topographic sheets)

Beginning at the Drift River Marine Terminal follow existing Drift River pipeline right-of-way north to West Foreland and Beluga. This terrain is essentially flat, marshy ground and can only be worked as a winter time operation off of snow pads - all materials must be barged in from the east side of Cook Inlet and temporary construction camps set up along the right-of-way. Camp site facilities are available at Drift River, Trading Bay and Standard Oils' Beluga installation. Air strip facilities exist at Drift River, Trading Bay and Beluga. Due to existing pipeline right-of-way, minimal negative environmental effect anticipated from additional pipeline construction operations.

Beluga to Palmer (84 Miles)
(Tyonek and Anchorage topographic sheets)

From Beluga to Point McKinzie follow Chugach Electric transmission line right-of-way across the mouth of the Big Suisitna River Delta. Terrain flat, swampy marsh lands suitable only for winter construction operations. Existing electrical transmission line right-of-way suitable for pipeline construction purposes. All material must be barged across from east side of Cook Inlet, however, there appears to be an abundance of local trails and roads suitable for pipe and equipment hauling.

From Point McKenzie area follow transmission line right-of-way north of Knik Arm up the Matanuska River Valley to Palmer. The existing road system from Goose Lake to Wasilla to Palmer should minimize pipe hauling and stringing operations. Utilization of existing right-of-way should minimize environmental problems. Terrain is high elevation and contains less lakes and swamp conditions.

Anchor Point to Soldatna (57 Miles)
(Seldovia and Kenai topographic sheets)

From Anchor Point follow the existing power line rights-of-way

north along the Sterling Highway to Soldatna. Ample right-of-way for pipeline construction appears to be available with minimal environmental impact anticipated if existing right-of-way is utilized. Right-of-way terrain is cleared of timber with scattered brushy areas.

Kenai River crossing south of Soldatna should be scheduled to avoid Salmon run season.

Between Soldatna and Sterling go north to pick up the existing Anchorage Natural Gas Company right-of-way. This existing cleared pipeline right-of-way is an excellent route across the moose range and should have a very minimal environmental impact. This route avoids most of the major swampy areas and could be constructed in either summer or winter. This route continues to Burnt Island on the south side of Turnagain Arm.

Turnagain Arm Crossing (5 Miles)
(Seward and Anchorage topographic sheets)
This proposed crossing of the Turnagain Arm parallels the dual line crossing installed by Anchorage Natural Gas Company. The recommended crossing point is approximately 500' west of the existing lines from Burnt Island across to Potter on the Anchorage side of the arm. No environmental problems are anticipated in installing a parallel system to the existing lines. Lines should be buried across tidal mud flats.

Turnagain Arm to Palmer (48 Miles)
(Anchorage topographic sheets)
From Potter on the north side of Turnagain Arm it is recommended to follow the existing Anchorage Natural Gas line right-of-way along the foothills east of Anchorage, east of Campbell Air Strip and north to Fort Richardson and Eagle River. From Eagle River north to Palmer follow existing power line right-of-ways along the Glenn Highway across the Knik River, Matanuska River and on into Palmer.

Palmer to Fairbanks (314 Miles)
(Anchorage, Tyonek, Talkeetna, Talkeetna Mts., Healy and Fairbanks topographic sheets)

For the Palmer to Fairbanks alternate route follow Highway 3 west out of Palmer to Willow. Workable right-of-way exists between the highway and the Alaska Railroad right-of-way. From Willow continue to follow Highway 3 and the R.R. right-of-way northerly along the Chulitna River Valley. Terrain is low rolling and swampy with available space for a pipeline adjacent to Highway 3. Continue up the Chulitna Valley through Broad Pass to Cantwell. Highway 3 continues north along the east side of Mount McKinley National Park through the narrow Nenana River Valley. Pipeline right-of-way through this stretch of terrain is narrow and rocky from McKinley Park to Garner. From Lignite north along Highway 3 fair to good right-of-way exists across the Early Warning Missile Range and on up to Nenana. From Nenana to Fairbanks, Highway 3 runs through broken foothills with limited space for a pipeline right-of-way along the highway to Fairbanks.

Palmer to Delta Junction (279 Miles)
(Anchorage, Valdez, Gulkana, Mount Hayes topographic sheets)

From Palmer the proposed right-of-way runs north easterly along Highway 1 (the Glenn Highway) ample cleared space is available on either side of the highway along and under existing power lines to afford an adequate pipeline construction route. Terrain along the Matanuska River Valley is primarily valley glacial moraine deposits which could be easily worked for pipeline construction. Good existing right-of-way exists all along Highway 1 up to Glennallen. From Glennallen the proposed pipeline route travels north along Highway 1 and 4 to Gakona Junction. From Gakona Junction fair to good existing cleared right-of-way is available along the Richardson Highway, #4, north to Delta Junction. A possible alternate for this section of pipeline could be to lay the gas line along the existing Alyeska pipeline right-of-way from Glennallen to Delta Junction.

Palmer to Tok Junction (267 Miles)
(Anchorage, Valdez, Gulkana, Nabesna and Tanacross topographic sheets)

The Palmer to Tok Junction follows the same Highway 1 route from Palmer to Glennallen as previously described and also Highway 1 and 4 from Glennallen to Gakona. At Gakona this proposed route continues north easterly along the continuation of Highway 1 (the Glenn Highway). North of the Cupper River, fair to good existing right-of-way is available for pipeline construction. This Glenn Highway route continues north easterly to cross the Chistochina River at Sinona Lodge up and over Mentasta Pass and on north to Tok Junction.

This alternate from Palmer north to the proposed Alcan gas line appears to have the best existing available right-of-way of all the routes observed.

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ECONOMIC ANALYSIS OF ALASKAN ROYALTY GAS CONTRACTS

a report to

STATE OF ALASKA: THE LEGISLATURE

JENSEN ASSOCIATES, INC.
Boston, Massachusetts
Washington, D.C.

AGO 544879

ECONOMIC ANALYSIS OF
ALASKAN ROYALTY GAS CONTRACTS

A Report to

STATE OF ALASKA: THE LEGISLATURE

January 1977

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APPENDIX A

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I. INTRODUCTION AND SUMMARY

INTRODUCTION

Three contracts for the sale of the State of Alaska's royalty gas from the leases on the Prudhoe Bay oil and gas field have been negotiated by the State of Alaska with Tenneco Alaska, Inc., El Paso Natural Gas Company, and Southern Natural Gas Company. These contracts must be approved by a majority of each House of the Alaska State Legislature. The Legislative Affairs Agency, acting on behalf of the Alaska State Legislature, has retained Jensen Associates, Inc. to perform an economic analysis of the State of Alaska's Proposed Royalty Gas Sales Agreements. The economic analysis of these proposed agreements is presented in this report.

The purpose of our analysis is to determine if the contracts protect the interests of the State of Alaska. In this analysis, we were asked to examine two questions:

1. Is Alaska protected if the El Paso project is not the one selected? and
2. If the El Paso project is approved, does the contract provide favorable value to Alaska?

SUMMARY

Alaska will receive favorable benefits from royalty gas either by obtaining the highest possible price from the sale of gas into interstate markets or for soundly based use in Alaska. Because of the large volumes of royalty gas available and because of the possibility of additional gas discoveries near Alaskan markets for natural gas, the more important question for this analysis appears to be the price that Alaska can receive in interstate markets. Second, it is necessary to analyze the flexibility built into the contract to allow Alaska to use the gas for its own needs.

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There is significant uncertainty about the price of the Prudhoe Bay royalty gas. Table I-1 illustrates this range where it shows the possibility of prices ranging from $0.20 to above $2.00 per Mcf. The uncertainties in the value of the gas and thus risks to Alaska are caused in part by uncertainties in energy markets, but much more importantly are caused by the uncertainties surrounding the legislation and regulation of natural gas.

The initial deliveries of Prudhoe Bay natural gas will occur at a time when--in our view--significantly increasing prices for energy world-wide are likely. Between now and 1985, we believe that the Organization of the Petroleum Exporting Countries (OPEC) is not likely to lose control of international oil pricing despite occasional periods of surplus and some degree of internal dissention within the organization. Beyond 1985, however, the possibility exists for sharply higher real world oil prices. This would result from continued growth of world oil demand combined with growing producing capacity limitations in many OPEC countries, thereby creating the conditions for shortage pricing by those few national oil suppliers who can still respond to world demand growth.

Between now and 1985, U.S. energy prices should rise because of (1) OPEC oil prices rising to keep pace with inflation in industrialized countries, (2) a rise in U.S. oil prices to approximate world oil levels as the current domestic price controls are relaxed or eroded, and (3) the U.S. beings to use higher energy prices to foster energy conservation as do Japan and the countries of Western Europe. Beyond 1985, much greater price uncertainty exists, but in our view, rising real prices are the most likely possibility.

The value of Prudhoe Bay gas netted back to the wellhead from No. 2 oil market values in California and the Midwest are shown in Table I-1 for 1980. Because the market price of No. 2 oil is expected to increase, and perhaps sharply, over the

TABLE I-1

RANGE OF POSSIBLE WELLHEAD PRICES FOR

PRUDHOE BAY NATURAL GAS

1980

Market Values via El Paso Project*	Dollars per million Btu
Competing with No. 2 oil**	
Mid West	0.94
California	1.22
Competing with coal based synthetic natural gas	
Mid West	2.71 - 3.05
Regulated Values	
Opinion No. 770 National Rate on new gas	
$1.42 plus $0.01 per quarter from October 1, 1976	1.56***
Possible Alaska Area Rate****	0.20 - 0.45

*Assuming F.P.C. staff estimate of gas capital transportation costs and netback value for fuel cost.

**Equivalent Btu value with No. 2 oil giving natural gas a 10 percent form value premium.

***If the prices are regulated using more recent drilling costs and discovery data, the cost based price should rise above that shown here.

****Computed with only Alaska data including associated gas.

twenty-year contract life, the netback market values will be higher than the 1980 wellhead price shown.

The greatest uncertainty about price is caused by uncertainty over legislation and regulation. If new gas is deregulated and Prudhoe Bay gas qualifies as new gas, as it will under some bills, then market value pricing will prevail. If wellhead prices continue to be regulated, Prudhoe Bay prices remain uncertain. Recent national rate opinions by the Federal Power Commission (F.P.C.) have specifically excluded Alaska and Hawaii from both the rates and the cost calculations that underlie the rates. If Alaska is included in the national rates as currently computed based only on non-associated gas, the prices will change little from current calculations because of the small amount of Alaska non-associated gas. However, if the vintaging formula under the most recent national rate decision, (Opinion 770-A), were to prevail, in which well spud-date determined the vintage, then some gas would not qualify for the new gas rate. However, vintaging is not the source of great price uncertainty. If regulation does not include Alaska in the national rate and an area rate is set for Alaskan reserves as the associated gas of Prudhoe Bay sets the possibility for lower wellhead prices. Since some of the costs of exploration and development will be allocated to oil for an associated gas discovery, and the Prudhoe Bay field is large, the costs per Mcf of gas is low as shown in the sample calculation in Table I-1. However, such a calculation assumes that the F.P.C. will depart from its recent tradition of excluding associated gas from its national rate calculations as had been done earlier in F.P.C. history. In any case, regulatory decisions can have great impact upon the value to Alaska of the Prudhoe Bay royalty gas.

CONCLUSIONS

The termination clauses built into the contracts protect Alaska in the event that the El Paso project is not approved or that there is excessive delay in approvals.

If the El Paso project is approved or if the terms of the contract prevail under another pipeline route, then the pricing provisions and the reservation clauses become important. The most important question is how does the contract protect Alaska's interest in the face of considerable price, regulatory, and legislative uncertainty. Our conclusions are:

- Future wellhead prices of Alaskan natural gas will be determined either through regulatory processes as they are now, or through price negotiation should Congress deregulate natural gas.
- In the event of deregulation, the contract will play a significant part in price determination. The pricing clauses with periodic redetermination, assuming a proper clarification of the ambiguity of redetermination relative to Section 6.3, are sound.
- If wellhead price regulation remains in force, the role of price determination will remain with the Federal Power Commission, or possibly with Congress and the contract itself can do little to influence the price. It is important to recognize that the contract has adopted a passive stance, having tied itself to the efforts of the producers in obtaining a ceiling price. Since no real precedent for price setting of Alaskan associated gas exists at present within the F.P.C., and since the strength of the producers' gas is not known, the state might have a stronger future position by setting its own price precedent now in this contract under Section 6.2.
- In addition, there is ambiguity in the interpretation of the price including severance taxes on royalty gas under regulation. This may keep severance taxes or their equivalent from being collected on the royalty gas at a loss of $50-$150 million dollars. The ambiguity needs clarification either in the contract or through Alaskan severance tax legislation.

The clauses reserving gas for Alaska are very good and provide significant flexibility. The State can make both time and location exchanges when they provide a better value for natural gas to Alaska than by selling interstate.

Finally, favorable value of the gas will be brought to Alaska more by action outside the contract in legislation and regulation than by the contract itself.

II. SUMMARY OF CONTRACT

The proposed sales by the State of Alaska of 2.6 trillion cubic feet of Prudhoe Bay royalty gas to Tenneco Alaska, Inc., El Paso Natural Gas Company, and Southern Natural Gas Company are designed to help Alaska in three ways:

1. Promote the construction of a trans-Alaska gas pipeline system, with the associated benefit of making gas available close to people and industry;
2. Establish a gas pricing structure favorable to Alaska for sale of royalty gas outside the State; and
3. Protect future needs for gas within Alaska.

A brief review of the contract mechanisms designed to implement the above goals follows.

PROMOTE TRANS-ALASKAN PIPELINE ROUTE

Article I of the contracts (entitled Support for Trans-Alaska Pipeline) requires both the State of Alaska and the royalty gas purchasers to work actively for the selection of a trans-Alaska gas pipeline system. The provision in Article XI (Conditions Precedent) that the royalty gas contracts may be terminated by directive of the Governor of Alaska if another route is approved appears to give sufficient motivation to the buyer to work hard in its endeavors to seek passage of a trans-Alaska pipeline route. Alaska's interests are adequately protected on this point. Alaska may choose to support any trans-Alaska pipeline route, although the State has indicated a preference for that proposed by El Paso Alaska Company. Alaska may also terminate the contract if pipeline route approvals are not forthcoming by December 31, 1978 or if a route other than El Paso's is approved.

ESTABLISH FAVORABLE GAS PRICING STRUCTURE

In order to obtain favorable prices for Alaskan royalty gas, the contracts establish different pricing mechanisms depending upon the regulatory or non-regulatory status of the gas. Article VI (Price) identifies three regulatory situations which might occur:

Section 6.2: Federal Power Commission has jurisdiction at the time of first deliveries over royalty gas resale rates in interstate commerce;

Section 6.3: No Federal Power Commission rate-regulation exists for royalty gas for interstate resale at the time of first deliveries; and

Section 6.4: Federal Power Commission deregulation occurs after first deliveries of royalty gas have begun.

If Federal Power Commission jurisdiction applies, the initial price of the royalty gas is to be the highest applicable rate allowed and never less than the price paid producers for their gas from the same reservoir for comparable interstate sales. If regulation does not apply, then the initial price is to be the highest interstate price being paid producers for similar sales from the applicable Prudhoe Bay leases.

If deregulation occurs after first deliveries, the price is subject to redetermination with a provision for arbitration in the event that price accord can not be reached. Annual redetermination may occur thereafter at the request of either buyer or seller. In all cases, the gas price is adjustable up or down if the gross heating value is more or less than 1,000 British Thermal Units (Btu's) per cubic foot.

Since no specific prices are established in the contracts, our analysis focusses on three issues:

1. The likely U.S. and world energy marketing context facing Alaskan royalty gas in the period 1980 and beyond. Chapter III examines energy economic trends in the U.S. and world pressures on energy prices in that period;
2. The market value of Alaskan royalty gas at the time of actual deliveries (Chapter III); and
3. Possible pricing formulas that may apply in the event of price regulation existing at the time of royalty gas deliveries (Chapter III).

Two additional aspects of natural gas pricing--vintaging and severance taxes--are considered in our analysis.

Vintaging refers to the date assigned to an interstate gas sale to determine the applicable regulatory price. Severance taxes are state-imposed producer taxes on gas extraction. The implications of vintaging and severance taxes to the contracts are discussed in Chapter III also.

PROTECT ALASKA'S FUTURE GAS NEEDS

Alaska clearly desires to retain future access to Prudhoe Bay gas for internal requirements. Under Article III (Quantity), the State has the right to reduce the quantity of royalty gas for interstate sale by varying percentages throughout the life of the contract. Alaska may retain 25% of the royalty gas for the first five years and increase this amount by 25% in each subsequent five-year period over the life of the contract. Alaska also has the right to change the percentages of royalty gas taken for internal needs upon a 24-month written notice as well as to export products, such as ammonia, manufactured from its retained gas. While the three contracts also contain "take-back" provisions enabling the buyer to recoup the quantities retained by the State to meet internal needs, this applies only if additional surplus royalty gas is available. Chapter IV of this report considers possible situations in which Alaska retains royalty gas for internal usage.

Finally, in reviewing the royalty gas contracts, some concerns arose regarding specific contract language. While relatively minor, these points are outlined in Chapter V. It is also recognized that in the process of negotiating a contract, both parties must "give and take" on the various issues. Since Jensen Associates, Inc. was not involved in the negotiating process, we acknowledge that some of the matters on which we comment here may have been dealt with in the negotiations themselves. Nevertheless, the issues are outlined in the report in accordance with our obligation as consultants.

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III. SALE OF PRUDHOE BAY NATURAL GAS

Alaska wants the most favorable price it can obtain for its royalty gas sold into interstate commerce. As we look ahead, we see considerable uncertainty about the price of energy in general and specifically about the price of natural gas in Alaska which may prevail when initial deliveries of royalty gas occur and for the subsequent twenty years over the term of the contracts. These uncertainties were apparently understood in the negotiation of the royalty gas contract. The contract pricing clauses simply state that the price shall be set at the highest price determined for comparable contracts, and if deregulation occurs, periodic price redetermination is established.

The uncertainty in price and thus risks in the payments to Alaska are created by forces outside the contract. These forces are markets and the course of natural gas regulation and/or legislation at the Federal level. This contract can influence the course of markets, regulation or legislation only slightly. However, the Legislature of the State of Alaska needs to be aware of and understand the causes behind these very real uncertainties about the price of Alaskan gas and their economic risk as it evaluates these contracts. Consequently, our evaluation of the contracts focusses more on contractual ability to adapt to changing price circumstances than upon the ability of the contracts to influence the prices.

In order to understand the extent and cause of the uncertainty about price of Alaskan royalty gas, we describe below the movement of energy markets in the United States and the world from 1975 to 1990, market value pricing of Alaskan gas which would prevail if deregulation of the wellhead price of gas were to apply to Prudhoe Bay gas, costs of alternate forms of energy for natural gas pipelines, and the impact and differences in pricing which regulation by a body such as the Federal Power Commission could bring to the price of Alaskan royalty gas.

ENERGY MARKETS IN THE UNITED STATES AND THE WORLD, 1975-1990

The Organization of Petroleum Exporting Countries (OPEC) has demonstrated since late in 1973 that it has considerable power to set the price of crude oil unilaterally in world markets. Western Europe, Japan, and increasingly the United States, as natural gas production declines, are dependent upon this imported oil which is the incremental source of energy in the industrialized nations and tends to set the price of all forms of energy. Consuming nations can influence price through controls or taxes to be more or less than the world market crude oil price. But controlling price below world market levels requires the nation to have its own energy production, as is true of the United States.

OPEC Production and Pricing

Table III-1 is the estimate of the world oil trade to 1985. The growing demands for OPEC oil production make a break-up of the cartel unlikely. We expect the United States to continue to rely upon imported oil, and, thus, be heavily subject to the world price of oil. The production of oil from OPEC nations should increase steadily but within productive capacities. In particular, Saudi Arabia, a country with the largest oil reserves in the world, should be able to accommodate increases in demand without strain to the mid-1980's.

The price of OPEC oil is not expected to decline, rather we expect the oil producing nations to attempt to maintain the value of their oil. As inflation continues in the industrial nations, the price of oil should increase apace to the mid-1980's.

Forecasts of oil, supply, demand and price are subject to an increasing range of error the further into the future the forecast is made. However, the contracts for royalty gas are scheduled to run for twenty years beyond the initial deliveries of gas which should occur sometime between 1980 and 1985.

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TABLE III-1

WORLD OIL TRADE

(Million barrels per day)

	1975	1980	1985
IMPORTS			
United States	5.8	11.5	11.5
Western Europe	12.4	12.0	14.0
Japan	4.9	6.0	8.0
Net to Balance[1/]	4.3	6.5	9.5
OPEC PRODUCTION			
Total	27.4	36.0	43.0
Saudi Arabia[2/]	7.1	10.0	12.0

1/ Includes net imports (exports) of the Non-OPEC developing countries, the Sino-Soviet countries, OPEC internal consumption, stock changes, and adjustments.

2/ Includes 50% of Neutral Zone.

Source: Jensen Associates, Inc.

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Thus, most of the gas under these contracts will be delivered after 1985, the time horizon to which most international oil forecasters have recently chosen to limit their estimates. In order to understand how energy prices will behave in the latter part of the 1980's and beyond, it is important to review the likely trends in world oil consumption compared with the development of both non-OPEC and OPEC supply.

Oil will be a major source of energy into the 1990's and beyond. Even though non-traditional energy sources may begin to grow rapidly, they do so from a small base so that continued economic growth needs to be, for some years after 1985, fueled by oil. But as oil demand on OPEC production increases, production capacity limits for most of the OPEC countries could very likely be strained. It is not hard to see oil demand bumping up against capacity constraints most everywhere except in Saudi Arabia after 1985. If this were to happen, the conditions would be set for another dramatic upward shift in the price of oil. It is also possible to envision very effective conservation efforts and accelerated alternate energy supply programs being developed, in which case the strains on OPEC production capacity would not be severe and oil price increases would be moderated. However, it is difficult to envision a decline in OPEC production in the decade following 1985 which would place downward pressure on world oil prices unless the industrialized nations of the world were to sink into depression.

As the time of initial deliveries of royalty gas nears, the post-1985 energy supply and demand balances will become clearer. These forecasts should begin to have a significant impact upon domestic U.S. energy prices and government policy. The post-1985 conditions are unclear today and the range of uncertainty about energy prices is high. However, forces that would create sharply higher prices seem more likely than a worldwide depression that might force oil prices downward.

U.S. Price Controls

At the current time, the price of oil in the United States is controlled by the Federal government at levels below the world price. However, the price for "new" oil is higher than for "old" oil in order to encourage further exploration and the development of additional supplies. The stated intention of the Energy Policy and Conservation Act is to allow the price of oil to increase and eventually for it to be decontrolled. Either as "new" oil becomes an increasing share of supply or oil price is decontrolled, the price of oil will increase more rapidly in the United States than in world markets as the U.S. prices catch up to the world prices.

U.S. Energy Conservation

There is a developing consensus in the United States that the conservation of energy is an important national objective. Currently, there is no equivalent consensus on how this objective is to be reached. There have been some attempts to use engineering standards mandated by regulation or legislation to promote energy conservation such as mileage requirements for new cars. Meanwhile, government policy has concentrated on keeping the price of energy low.

Other countries, such as Japan and those in Western Europe who have a longer history of oil imports than the United States, have relied upon the price system to bring about energy conservation. These nations increase the cost of energy to the consumer above world oil prices by taxation. Energy consumption in Japan and Western Europe is below that of the United States by more than can be explained by a difference in the standard of living. The use of the price system to bring about energy conservation has proven to be successful in other nations.

As the United States develops an energy conservation program, an increasing reliance upon higher energy prices to bring about conservation is to be expected. This, too,

should reinforce both the OPEC determined price increases, the price increases of oil and other energy forms in the United States as oil market levels are approached, to bring about an even greater increase in the price of energy for the United States.

Conclusion

OPEC oil pricing, the phase-out of oil price control in the United States or an increasing proportion of "new" oil, and greater reliance upon higher prices to foster energy conservation all point to increased energy prices in the U.S. The extent of these increases is uncertain. However, the greatest uncertainty is about prices in the mid-1980's. The potential for oil demand running hard against world productive capacity exists. Sharply increased prices would result. But, if the industrialized nations can aggressively conserve energy and develop sources other than oil, or if economic growth falters, then OPEC oil production capacity will not be under the same stress.

MARKET BASED VALUES OF NATURAL GAS

In the event of deregulation, market forces would determine the field price of Alaskan North Slope gas. One way to anticipate this price is to forecast the market price of alternate fuels and to netback to the North Slope using the costs of transporting the gas to market. The theory is that the price of natural gas at the market (e.g., Los Angeles) would tend toward a level related to the price of alternate fuels, and that the field price resulting would be the market price less the cost of transmission.

We have computed the netback value of Alaskan North Slope gas based on the market prices of competing alternate fuels in Los Angeles and Chicago. This section describes the method and the results of this analysis.

Number Two Fuel Oil

The calculations which compare natural gas with fuel oil are based on the projected prices of No. 2 oil in Los Angeles and Chicago. In the case of Los Angeles, it was assumed that No. 2 oil would be refined primarily from Alaskan crude, priced to be competitive with Saudi Arabian light landed in Houston. The present price of Saudi Arabian light is $12.09 F.O.B. Ras Tanura. This price can be inflated at 5% per year to 1980 and, with the addition of transportation costs, terminal costs and refinery margins, yields a projected price for No. 2 oil in Houston in 1980. Netting back to Los Angeles via crude pipeline results in a price for No. 2 oil refined from Alaskan crude and delivered in Los Angeles. A 10% premium must then be added to account for the fact that natural gas is often preferrable on a Btu basis to No. 2 oil.

To compute a price for No. 2 oil in Chicago, we added to the price of No. 2 in Houston the cost of transporting the fuel by product pipeline to Chicago. Again we added 10% to reflect a premium for clean-burning natural gas.

In both Chicago and Los Angeles, it was assumed that the relevant price comparison was between No. 2 oil at the refinery

rack and natural gas at the city gate. The cost of local delivery to large volume industrial users was assumed to be small and approximately equal for either fuel.

SNG from Coal

Current estimates for the cost of producing gas from coal form a range of between $3.00 and $4.00 per million Btu. To obtain a 1980 price for coal-based SNG, we selected $3.50 as a middle-range figure, inflated it at 8% per year for five years, and added projected transportation costs.

Netback Value

The netback value is computed in the following way. Suppose the projected market price of No. 2 in Los Angeles is $3.50 per MMBtu. Adding 10% results in a market value for natural gas of $3.85 per MMBtu, competing against No. 2 oil. In other words, pipelines could charge gas distributors in Los Angeles up to $3.85 per MMBtu, the price of the competing incremental fuel source. The field price in Alaska is then determined by subtracting from $3.85 the cost of transporting the gas from the field to Los Angeles. If the transport costs were $2.00 per MMBtu, then the price that Alaska could charge for its royalty gas in the field would be $3.85 minus $2.00 equals $1.85 per MMBtu.

It should be noted that transportation costs include the cost of gas used and lost along the respective routes. Consequently, transportation costs vary with the netback value which in turn varies with the projected market price of the competing fuel. In short, the higher the value of Alaskan North Slope gas, the more expensive it is to transport.

Tables III-2, III-3, and III-4 show netback values computed for the El Paso project and the Arctic Gas project separately.

Strictly speaking, netback values show what price would prevail for natural gas (regardless of source) in each market, assuming insufficient gas is available to replace the alternate

TABLE III-2

NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS
BASED ON NO. 2 OIL
1980
(Dollars per million Btu)

El Paso Route

	Price of No. 2 Oil (Incl. Premium)*	- El Paso Transportation Costs**	= Netback Value
Chicago	$3.34	$2.40	$ .94
Los Angeles	$3.10	$1.88	$1.22

Arctic Route

	Price of No. 2 Oil (Incl. Premium)*	- Arctic Transportation Costs**	= Netback Value
Chicago	$3.34	$1.68	$1.66
Los Angeles	$3.10	$1.40	$1.71

*Assumes that the current price of Saudi Arabian light ($12.09) will rise at the rate of 5% per year to 1980 and 7.4% per year from 1980 to 1985. These estimates are representative and merely reflect current expectations.

**Based on average fifth-year cost to the Mid West and California as published by the F.P.C. staff (12/7/76). Estimates assume 2.4 and 2.25 Bcf/d capacity for the El Paso and Arctic systems respectively. Gas lost or used as fuel in transit is valued at the netback value.

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NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS
BASED ON NO. 2 OIL
1985
(Dollars per million Btu)

El Paso Route

	Price of No. 2 Oil (Incl. Premium)*	- El Paso Transportation Costs**	= Netback Value
Chicago	$4.59	$2.61	$1.98
Los Angeles	$4.27	$2.08	$2.19

Arctic Route

	Price of No. 2 Oil (Incl. Premium)*	- Arctic Transportation Costs**	= Netback Value
Chicago	$4.59	$1.79	$2.80
Los Angeles	$4.27	$1.50	$2.77

*Assumes that the current price of Saudi Arabian light ($12.09) will rise at the rate of 5% per year to 1980 and 7.4% per year from 1980 to 1985. These estimates are representative and merely reflect current expectations.

**Based on average fifth-year cost to the Mid West and California as published by the F.P.C. staff (12/7/76). Estimates assume 2.4 and 2.25 Bcf/d capacity for the El Paso and Arctic systems respectively. Gas lost or used as fuel in transit is valued at the netback value.

TABLE III-4

NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS
BASED ON SNG FROM COAL
1980
(Dollars per million Btu)

El Paso Route

	Price of SNG Delivered*	- El Paso Transportation Costs**	= Netback Value
Chicago	$5.46	$2.75	$2.71
Chicago	$5.46	$2.41***	$3.05

Arctic Route

	Price of SNG Delivered*	- Arctic Transportation Costs**	= Netback Value
Chicago	$5.46	$1.87	$3.59
Chicago	$5.46	$1.61***	$3.85

*Current estimates place the cost of producing SNG from coal of between $3 and $4 per MMBtu in 1975 dollars. We have used $3.50/MMBtu and inflated at 8% per year to 1980. Cost of transporting SNG assumed to be 32¢/MMBtu.

**Based on average fifth-year cost to the Mid West and California as published by the F.P.C. staff (12/7/76). Estimates assume 2.4 and 2.25 Bcf/d capacity for the El Paso and Arctic systems respectively. Gas lost or used as fuel in transit is valued at the netback value.

***Assumes gas lost or used as fuel in transit is valued at $1.00/MMBtu.

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fuels. Of course, if all Alaskan gas were channeled into Los Angeles, saturation would occur and Los Angeles' market price of gas would fall. However, in the broader context of the national market, (which size is currently on the order of 55 billion cubic feet per day), the additional 3.5 billion cubic feet per day anticipated from Alaska may not be sufficient to render uneconomical even the most expensive alternate fuel sources now being contemplated.

Contracts

Section 6.3 of the contracts states that in the event of deregulation, prior to first deliveries of Alaskan North Slope gas, "the initial price for gas delivered hereunder shall be the highest price being paid by any interstate gas purchaser for gas under contracts. . . ." This provision appears adequate to insure that Alaska receives the full netback value based on the appropriate competing alternate fuel source, providing that the North Slope producers have marketed their gas judiciously; and with the price incentives inherent under deregulation, there is every reason to believe that they would do so.

Section 6.4 provides, moreover, for price redetermination in the event that the price of gas is regulated at the time of first deliveries and subsequently deregulated.

These two sections together provide that Alaska receives full market value for its royalty gas under deregulation, providing vintaging allows, whether or not deregulation occurs before or after the date of first deliveries. Moreover, inasmuch as Alaska contemplates taking royalty gas in kind, and selling it in the field, netback pricing serves to illustrate the market price potentially available to Alaska for its royalty gas.

COST-BASED REGULATION OF ALASKA GAS PRICES

In the event the sales of Prudhoe Bay gas contemplated in the contracts are found to be jurisdictional by the F.P.C., the price clause (Section 6.2) provides that

1. ". . . The initial price . . . shall be the highest area, national or ceiling rate allowed to be paid by any interstate gas purchaser to any working interest owner . . ."
2. "The price to be paid thereafter shall be subject to all periodic changes permitted in accordance with the . . . Rules and Regulations of the Federal Power Commission . . . or such other changes in price as may be permitted by any new area, national or ceiling rates . . . which may subsequently be established."

Thus, the value of the contracts depends upon the ceiling price which may be established by the Federal Power Commission. The contracts do not specify or assume that the nationwide rate established by the F.P.C. will apply to the contract sales. On the contrary, the contracts accept in advance, whatever rate-making method the F.P.C. might apply to sales of Prudhoe Bay gas. Moreover, the contracts tie the interests of the State of Alaska to the interests of the private companies producing Prudhoe Bay gas. The State will not receive a price for its royalty gas any higher than the cost-based price which the companies can justify to the F.P.C.

The National Rate and Alaska Gas

The current nationwide wellhead ceiling price for "new" natural gas in the United States is $1.42/Mcf (plus 1¢/quarter beginning October 1, 1976), established in F.P.C. Opinions 770 and 770-A. However, these Opinions and the earlier nationwide rate Opinion 699-H all explicitly excluded the States of Alaska and Hawaii.[1] A simple decision could be made by the Commission to delete the exclusion and thus bring Alaskan gas under the

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[1]Title 18, U.S.C., paragraph 2.56a (f).

nationwide ceiling. The difficulty with this approach is that the $1.42/Mcf is a cost-based ceiling price, calculated using cost data from only the lower-48 states. That is, the exclusion of Alaska from the $1.42/Mcf ceiling is not only a legal or procedural fact but also a computational fact. If the F.P.C. were to attempt to establish a single uniform national rate including Alaskan gas, the Commission would likely bring data on the cost of gas production in Alaska into the computation process.

One fundamental assumption underlying Opinions 699-H, 770 and 770-A is that most natural gas produced in the U.S. is from non-associated gas wells (wells which produce gas from reservoirs which do not also contain crude oil). For this reason the Opinions consider data on the drilling costs and drilling footage of gas wells only. All data on oil wells (many of which also produce gas) are excluded. If the F.P.C. were to revise the national rate to incorporate data on non-associated gas wells in Alaska, the national rate would not be much affected. The number of Alaskan non-associated gas wells and the quantity of Alaskan non-associated gas reserves are not large enough (relative to the national total) to have a significant impact upon the calculation of the national rate.

However, the inclusion of Alaska within the national uniform rate may be difficult precisely because of the fundamental assumption stated above, i.e. that most U.S. natural gas is produced from non-associated wells. Such an assumption, some may argue, is inapplicable to Alaska, where over four-fifths of natural gas reserves exist in conjunction with oil. For this reason, there is a reasonable possibility that the Commission will establish a separate area rate for all gas in Alaska or for casinghead gas from oil wells in Alaska.

An Area Price Ceiling for Alaska

The calculation of a wellhead ceiling price for all natural gas in Alaska, or for casinghead (associated-dissolved) gas alone, requires the allocation of costs between oil and gas. During the

long history of F.P.C. wellhead price regulation, many methods have been proposed for making such an allocation. Most of these methods have been based upon a combination of two principles:

- That oil and gas may be substituted for each other as sources of energy and are valuable because of their energy content as measured in Btu's, and
- That oil, which has traditionally sold at a higher wellhead price per Btu than gas, should receive a premium value over gas.

A brief review of F.P.C. wellhead price regulation uncovered no instance in which the Commission had actually allocated costs between oil and gas in order to set an areawide ceiling price on associated gas (called "casinghead gas" in the area rate opinions). In setting area price ceilings between 1961 and 1974, the Commission established various categories of gas according to vintage date. The calculation of the price applicable to each vintage category was based entirely upon the costs of non-associated gas production. Newer vintages of gas received higher ceilings than did older vintages, due to inflation of drilling costs and declining sizes of gas discoveries. Casinghead gas was included in the older vintage and was not vintaged in its own right. Thus, "new" casinghead gas received a lower ceiling price than did new non-associated gas.

The most recent case in which the Commission allocated costs to arrive at a separate cost of service for casinghead gas was in the Phillips Petroleum opinion of September 1960, the last of the individual producer rate cases. In the Phillips opinion, the Commission used separate methods for allocating production costs and for allocating exploration costs. Production costs on leases producing both oil and gas were allocated in proportion to the relative costs of producing oil from oil-producing leases and of producing gas from gas-producing leases. Exploration costs (which were viewed as joint costs because, at that time, the F.P.C. did not accept the concept of directional exploration) were allocated first among oil-only leases, gas-only leases and joint-product

leases on the basis of net investment in each of these three categories of leases. Then the exploration outlays assigned to joint product leaseholds were divided between oil and gas using a modified Btu method. The number of Btu's contained in crude oil produced from the joint-product leases in the test year was multiplied by 4 as an "economic factor" reflecting the then-prevailing higher market value of oil than of gas. Thus, the following fraction of joint-lease exploration costs was assigned to gas:

$$\frac{\text{Btu's of gas produced}}{(4 \times \text{Btu's of oil produced}) + (\text{Btu's of gas produced})}$$

The Commission stated that "we are of the opinion that the proper economic factor to be applied to the straight Btu content of oil to allocate Phillips' test year exploration costs is 4, so that the cost relationship of finding one Mcf of gas to one barrel of oil will be about 1 to 24."

Estimation of Alaskan Natural Gas Ceiling Price

Keeping in mind the long span of time which has lapsed since the Phillips precedent for separating oil from gas costs, we have, nevertheless, calculated several hypothetical ceiling prices for Alaska natural gas. These were calculated under the assumption that the F.P.C. would set an area ceiling price for the State of Alaska as a whole, with no differentiation within the State. It was also assumed that the Commission would follow a method roughly analogous to the present method used in setting the nationwide rate (that is, the method used in Opinion No. 770-A) with the following modifications:

- Data pertaining to drilling cost, drilling footage and reserve additions would be drawn from Alaska's experience only. Successful drilling cost and footage would include both oil and gas wells.
- Lead times between capital outlays and start-up of production could be considerably greater than those used in calculating the Lower-48 ceiling, and
- Unit costs would be divided between oil and gas on a Btu basis, or a value-modified Btu basis.

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Working entirely from published data (the same sources used by the F.P.C. in setting the nationwide ceiling price), we calculated wellhead ceiling prices which ranged from under 20¢/Mcf to about 45¢/Mcf. The higher end of this range was calculated assuming a straight Btu division of oil and gas, which is the most favorable calculation from the gas producer's standpoint. No allowance was made in these calculations for any special capital outlay for waterflood or other enhanced oil recovery operation necessitated by the removal of the natural gas drive mechanism in the reservoir.

F.P.C. Jurisdiction Over Alaska Royalty Gas

The basic presumption of government regulation of an exhaustible resource is that economic rents should be captured by the private consumers of the resource rather than by the private firms or individuals who own and produce the resource. This presumption reflects the present distribution of political power and influence between the two groups, the consumers and the producers. The purpose of setting a ceiling price based upon cost calculations is to carry out this allocation of rents.

The State of Alaska, as a public rather than a private producer and owner of resources, may not be subject to the same political arrangement which underlies cost of service regulation. That is, in addition to the legal argument that a State is not a "person" within the meaning of the Natural Gas Act, there is also an economic and philosophical argument that a State is vested with quite different and much broader social responsibilities than is a private firm. For this reason, the State may be entitled to capture a greater share of the resource rents than has been awarded by the political process to private resource producers. The contracts for the sale of Alaska royalty gas, as they are currently formulated, establish price by reference to a ceiling price established for private producers. Such pricing by reference appears to abdicate the position that the State, even if subject to regulation, should not be subject to cost-based regulation. It would

also appear to place the State in the position of accepting a regulated ceiling price established for private producers even if the State is not found subject to regulation.

As the representative of a diverse social group, the State may not wish to bind itself to prices received by private producers, because these prices may be determined without reference to the public nature of the State of Alaska.

VINTAGING

As presently written, the contracts for the sale of Alaskan royalty gas do not mention the possibility that several ceiling prices might simultaneously apply to gas from the Prudhoe Bay area. Such a circumstance could arise from whatever "vintaging" policy is chosen by the F.P.C. to apply to Alaska gas, and could have a significant impact on the value of Alaskan gas.

"Vintaging" refers to the establishment of a date--such as the date of discovery of the reservoir or date of commencement of the well--which separates the produced gas into two (or more) categories for pricing purposes. For example, the current national rate for interstate natural gas is $1.42 (plus 1¢ per quarter) for gas produced from wells commenced on or after January 1, 1975. Gas from wells commenced between January 1, 1973 and December 31, 1974 qualifies for a price of $.93 (plus 1¢ per annum). In this example, the date of well commencement ("spud date") is the vintaging criterion.

At the present time, Alaska is in a unique position. No existing vintaging basis clearly applies to Alaskan gas. Thus, Alaska is limited in its ability to address future vintaging treatment of royalty gas through the terms of the sales contracts. Alaska can, however, strengthen its future position by clearly understanding the implications of vintaging and being prepared to act through regulatory intervention or otherwise at a future date. This chapter attempts to clarify the vintaging issues pertinent to royalty gas contracts.

Vintaging Under the Uniform National Rate

For Alaskan royalty gas to qualify for the highest national rate, under present vintaging methods, the gas must be produced from wells spudded in after January 1, 1975.

The "spud-in" date is the moment of drilling the first foot of a well regardless of the date of completion or recompletion. Well completion refers to the installation of permanent equipment for the production of oil or gas. The date of completion of an oil well or gas well is the date on which the installation of permanent equipment has been completed for the production of oil or gas as reported to the appropriate regulatory agency.

Depending upon the gas field or reservoir drilling development pattern, spud-in date may or may not be a vintaging basis favorable to Alaska. If most gas is produced from wells spudded-in after January 1, 1975, then Alaska may qualify for the highest available national rate for most of its gas if the national rate applies to Alaska. If the royalty share comes from wells spudded-in at a considerably earlier date than the January 1, 1975 cut-off, then Alaska clearly is in a less favorable position vis-a-vis the national rate. At the present time, wells spudded-in on or after January 1, 1973 and before January 1, 1975 receive separate national rate treatment from the F.P.C. while gas from wells commenced prior to January 1. 1973 receive rate treatment under F.P.C. Opinion No. 749 which has established a price of 29.5¢/Mcf nationally for "old" gas. Clearly, the maximization of Alaskan royalty gas revenues will depend on the type of vintaging mechanism allowed under regulation.

Other Vintaging Methodologies

In the evolution of gas pricing regulations, the Federal Power Commission has used various methods for determining the vintage of gas. Other regulatory vintaging methodologies have used contract date, type of gas, date of dedication to interstate commerce, and reservoir discovery date. Table III-5 details the vintaging mechanisms in national and area rate regulation as well as in two proposed 1975-76 deregulation bills.

TABLE III-5

SUMMARY OF NATURAL GAS VINTAGING APPROACHES RELATED TO INTERSTATE PRICE REGULATION

VINTAGING APPROACH	ALLOWED HIGHEST APPLICABLE RATE FOR: Type of Gas: Associated or Oil Well Gas	Type of Gas: Non-Associated or Gas Well Gas	Qualifying Date for "New" Gas Vintage: Spud-In Date	Qualifying Date for "New" Gas Vintage: Recompletion Date	Qualifying Date for "New" Gas Vintage: Date of Initial Interstate Dedication	Qualifying Date for "New" Gas Vintage: Date of Contract	Qualifying Date for "New" Gas Vintage: Date of Reservoir Discovery	RATE ESCALATION
1. National Rate								
a. Opinion 770-A (November 1976)	yes	yes	yes	no	no	no	no	yes
b. Opinion 770 (June 1976)	yes	yes	yes	yes	yes	no	no*	yes
c. Opinion 699-H (December 1974)	yes	yes	yes	yes	yes	no	no*	yes
2. Area Rate								
Permian Basin Opinion 468 (August 1965)	no	yes	no	no	no	yes	no	no
3. 1975-1976 Proposed Deregulation								
HR 10480 Krueger-Broyhill Bill (October 31, 1975)	yes**	yes**	yes	no	yes	no	no	As Per Contract
S-3422 Pearson-Hollings Bill (May 12, 1976)	yes	yes	yes	yes	yes	no	yes	yes

*Date of discovery of a new gas reservoir on acreage previously dedicated to the interstate market was a vintaging criterion.

**If producer is not affiliated with a pipeline.

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Contract date and type of gas were used together in the first area rate vintaging methodology (Opinion No. 468 issued August 5, 1965). In this case, an established date (January 1, 1961) was the dividing date between old and new gas with new gas being that which was sold through a contract dated after the January 1, 1961 date. However, this system also vintaged gas on the basis of whether it was gas well gas or oil well gas. All casinghead gas (or oil well gas) was categorized as old gas; only post-January 1, 1961 gas well gas received new gas treatment. Similar vintaging methodologies were used in other area rates established by the F.P.C. with some variations as to the applicable contract vintaging date. The pricing implications for Alaskan royalty gas if vintaging occurs on a basis comparable to area rate regulation are considered elsewhere in this chapter. Alaska should understand, however, that by stating a contractual willingness to accept an area rate with its inferred vintaging mechanism, it may face future rate rulings that are either unanticipated or clearly less favorable than more recent pricing regulations.

Vintaging on the basis of first sales into interstate commerce (under contracts executed after a specified date) has also been used by the F.P.C. in the first uniform national rate (June 1974). This methodology has been superceded by well commencement date vintaging. Date of first sales into interstate commerce appears to be an attractive vintaging basis. It has a clear disadvantage, however, if the market value of gas is expected to rise over the term of the contract by committing all the gas to a price set when market value was lower.

Conclusions

1. No single vintaging method yet applies to Alaskan royalty gas and Federal Power Commission actions on this are uncertain.

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2. Revenues to Alaska for royalty gas sold interstate are highly dependent upon the vintaging method selected.

3. No single vintaging system is clearly superior to all others, although in general, the more gas that falls into the "new gas" category or vintage, the greater are Alaska's opportunities to maximize royalty revenues.

Vintaging Under Proposed Gas Legislation

Numerous proposals to deregulate or reregulate natural gas pricing were introduced into the 1975-76 Congressional Session, and already in the current Congress eleven bills as of this writing have been proposed. Passage of a particular bill at this time is unclear. However, based on 1975-1976 bills, vintaging is likely to remain an issue in current proposed legislation of great economic significance to Alaska.

The importance of future deregulation or reregulation to Alaska's royalty gas contracts is the possibility that there may be multiple vintages applicable to the Prudhoe Bay gas. That is, depending upon the vintage method, there may be a deregulated and a regulated price in effect at the time of first deliveries.

SEVERANCE TAXES ON ROYALTY GAS

It is possible that $50 - $150 million[1/] in revenue might be lost to Alaska from an interpretation of price in Section 6.2, 6.3, and 6.4. While the Alaskan severance tax legislation currently does not apply to state-owned royalty interests, the price clause should not preclude by omission the collection of a severance tax or revenue in lieu of severance taxes on Alaskan royalty gas in addition to the base price. Under F.P.C. regulation, the price paid to a producer by a pipeline for the working interest share will be adjusted upwards from the ceiling rate to cover severance tax. This payment for severance tax is in turn fully recovered by the pipeline. If a severance tax on the Alaskan royalty interest is not charged in addition to the highest allowable area, national or ceiling rate under some interpretations of the gas contract pricing clauses, the price for royalty interest gas will be less than the price paid by pipelines for the working interest portion. In the condition that Alaska is not subject to F.P.C. jurisdiction, the royalty gas will be sold at the highest price paid by a purchaser which appears to be wording that would cover severance taxes paid by the working interest holder. Given the amount of money involved, we suggest legal review on the point of collecting severance taxes. The possibility for a low price differential on Alaskan royalty gas may be eliminated in one of two ways:

(1) legislative action to include the royalty interests taken in kind with that production which is subject to a severance tax, or

(2) a change in the contract which sets the price of Alaskan royalty gas at the highest allowable price plus an adjustment in lieu of a severance tax.

1/ For sale of 2.6 tcf at $0.50 to $1.50 per million Btu assuming one million Btu per Mcf and a 4% severance tax.

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IV. USE OF GAS WITHIN ALASKA

The State of Alaska is permitted to reduce the volumes of gas sold under the contracts. Any reduction may be made on twenty-four months' notice, or up to specified limits on twelve months' notice, provided the gas is to be used for "domestic or industrial" purposes in Alaska.

As presently written, the contracts do not specify whether the withdrawn gas must be for current or anticipated domestic or industrial needs. It is possible that Alaska might predict or foresee a need for natural gas within the State which extends beyond the term of the contract, or an increasing demand for intrastate gas which will eventually exceed the total volume of royalty gas during the term of the contract. We see no contract impediment to a time exchange of royalty gas which might be worked out with the owners of the working interests.

For example, the province of Alberta follows a rule of protecting provincial requirements for a forecast 30-year period before permitting additional interprovincial sales. A similar rule could be applied by Alaska.

As shown in Table IV-1, natural gas consumption in Alaska during 1975 was 66.8 billion cubic feet, none of which came from the North Slope. If the total contracted amount of royalty gas (2.6 trillion cubic feet) were produced uniformly over a 20-year period, the annual volume of royalty gas would be 130 billion cubic feet. Thus, if all additions to intrastate natural gas consumption had to be drawn from the royalty gas in the contracts, then Alaskan gas consumption would have to triple over present levels before all the royalty gas would be withdrawn from the contracts.

Gas utility sales in Alaska grew at an average rate of 12.7% per annum from 1965 to 1975 and at a rate of 12.1% from 1974 to 1975. Total consumption of gas in Alaska rose from

TABLE IV-1

NATURAL GAS CONSUMPTION IN ALASKA

1975

User	Sales by Gas Utilities Bcf 1/	Total Consumption Bcf
Residential	5.6	10.4
Commercial	6.4	8.5
Industrial		22.4
Electric Utilities	12.8	19.6
Other	5.9	5.9
Total	30.7	66.8

1/ Bcf = Billions of cubic feet

Sources: U.S. Bureau of Mines, Mineral Industry Surveys; American Gas Association, Gas Facts 1975

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42.0 Bcf in 1971 to 66.8 Bcf in 1975 or at an annual rate of 11.6%, as shown in Table IV-2. Growth of the natural gas industry has been from a fairly small base figure, so that a projection of recent rapid growth rates may be unrealistic, at least in areas already well served by gas. However, even if it is assumed that growth continues at the somewhat reduced rate of 6% per annum, Alaska's internal gas consumption would triple in about 18 years. If the slightly faster rate of growth of 10% occurs, consumption will triple in about 11 years. In either case, internal consumption would outstrip the annual volume of royalty gas before the end of the term of the 20-year contract. Moreover, the level of intrastate demand achieved by the end of the contract term could not be sustained by royalty gas from Prudhoe Bay beyond the productive life of that area. However, areas closer to Alaskan gas markets such as the lower Cook inlet may be the source of future growth in natural gas supply.

AMMONIA PRODUCTION

As a part of our economic analysis of the contracts for the sale of royalty gas, we have considered the possibility that Alaska might prefer to export manufactured products which use gas as a feedstock rather than exporting the natural gas itself. The principle argument would be that the value added (wages, salaries, profit) would thereby be retained for the Alaskan economy.

We considered, in particular, industries which are heavily dependent upon natural gas, such as ammonia manufacture. We determined that, if all of the Alaskan royalty gas were devoted to ammonia production, Alaska would then produce about 30% of the present U.S. level of ammonia output. Ammonia production in the U.S., although it is one of the most intensive industrial uses of natural gas, nevertheless consumes only a small fraction (a little over two percent) of total

TABLE IV-2

GROWTH OF NATURAL GAS CONSUMPTION

ALASKA 1971-1975

Use	1971 Bcf[1/]	1975 Bcf	Average Annual Rate of Growth
Residential	6.9	10.4	10.3%
Commercial	7.5	8.5	3.1
Industrial	10.6	22.4	18.7
Electric Generation	10.3	19.6	16.1
Other	6.7	5.9	-3.2
Total	42.0	66.8	11.6%

1/ Bcf = Billions of cubic feet

Source: U.S. Bureau of Mines, Mineral Industry Surveys

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U.S. natural gas production. The U.S. ammonia market simply could not absorb such a large increment in supply.

Moreover, planned additions to ammonia capacity in the lower 48 states are already quite large, amounting to 3.2 million metric tons per year, or a 22% increase over present capacity. As shown in Table IV-3, principal U.S. markets for ammonia fertilizers are in the Midwest, an area more accessible to ammonia plants in Texas, Louisiana or Alberta than to ammonia plants in Alaska. European markets for nitrogen fertilizer probably could be served more economically from the Persian/Arabian Gulf, and thus may not be a prospective long-run market for ammonia from Alaska.

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TABLE IV-3

UNITED STATES NITROGEN FERTILIZER CONSUMPTION

BY GEOGRAPHIC AREA

1974

(In 10^6 Pounds)

	Quantity	Percent of Total
West Coast [1/]	1,301	7.8
Upper Midwest	10,096	60.8
Lower Midwest	3,111	18.8
Atlantic Seaboard	2,084	12.6
Total United States	16,592	100.0

[1/] Includes Washington, Oregon, and California

Source: U.S. Department of Agriculture

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V. CONCERNS ABOUT CONTRACT AMBIGUITIES

This chapter comments on several specific details in the royalty gas contracts which appear to need clarification. Each point below is keyed to the section of the contract pertinent to the issue. We have suggested possible remedial actions in each case.

1. ARTICLE III (QUANTITY); SECTION 3.7(a):

This section refers to the terms under which the buyer may purchase additional quantities of surplus Alaskan royalty gas in the event that Alaska has previously implemented its option to remove contract gas for intrastate use. Section 3.7(a) continues to be applicable for a period of five years after expiration of the term of the contracts.

The governing price of surplus royalty gas offered to buyer after expiration of the contract and in the event of no other interstate bona fide purchasers is unclear. This section states only that,

> "In the event there are no other interstate bona fide purchasers, the price shall be the price then being paid by Buyer for gas purchased under this Agreement." (Underscoring inserted.)

Contract clarification of the applicable price is needed in the event deliveries have already been completed under the contract and no outside interstate purchasers exist.

2. ARTICLE VI (PRICE); SECTIONS 6.3 - 6.5:

Section 6.4 (deregulation after commencement of first gas deliveries) clearly provides for a price redetermination to occur as outlined in Section 6.5. Section 6.3, however, which provides for an initial price in the event of non-regulation existing at the time of first deliveries does not contain a price redetermination clause. Since Section 6.5 makes specific reference only to Section 6.4, it is unclear that price redetermination will also

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occur in the event Section 6.3 is operative. Insertion of a clause in the contracts indicating that a price redetermination will occur in the event Section 6.3 applies is suggested.

3. ARTICLE VI (PRICE):

This Article of the contracts does not address a pricing situation in which the initial gas sales are not subject to F.P.C. regulation but, later in the contract term, become jurisdictional. Such a scenario could occur as a result of (1) judicial appeal of an initial F.P.C. ruling; (2) deregulation of gas prices conducted on a temporary or experimental basis, such as was proposed by President Carter during the election campaign; or (3) Federal action overriding the F.P.C. (e.g., creation of a general price and wage control policy).

APPENDIX A

TABLE 1

F.P.C. NATIONAL RATE RULINGS

F.P.C. Opinion No.: 699

Date Issued: June 21, 1974

Definitions of "new" gas:

(1) Sales of natural gas in interstate commerce made from wells commenced on or after January 1, 1973.

(2) Sales of natural gas in interstate commerce made pursuant to contracts executed on or after January 1, 1973 for

(a) gas not previously sold in interstate commerce (except under specified F.P.C. certificates); or

(b) where the sales were formerly made pursuant to permanent certificates of unlimited duration under contracts which expired by their own terms on or after January 1, 1973.

Applicable Rate: 42¢/Mcf with 1¢/annual escalation beginning January 1, 1974

F.P.C. Opinion No.: 699-H

Date Issued: December 4, 1974

Definitions of "new" gas:

(1) Sales of natural gas in interstate commerce from a well or wells commenced on or after January 1, 1973.

(2) Sales made pursuant to contracts for the sale of natural gas in interstate commerce

(a) for gas not previously sold in interstate commerce prior to January 1, 1973 (except under specified F.P.C. certificates); or

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(b) where such sales are initiated on or after January 1, 1973 provided the sale has not been certificated under the F.P.C.'s optional procedure.

(3) Sales made pursuant to contracts executed prior to or subsequent to the expiration of the term of the prior contract where the sales were formerly made pursuant to permanent certificates of unlimited duration under such prior contracts which expired of their own terms on or after January 1, 1973, or pursuant to contracts executed on or after January 1, 1973, where the prior contract expired by its own terms prior to January 1, 1973.

(4) Gas produced from newly discovered reservoirs located upon acreage previously dedicated to interstate commerce under a contract dated prior to January 1, 1973, shall have the rate determined by the date of reservoir discovery in lieu of the contract date.

Applicable Rate: 50¢/Mcf and 1¢/annual escalation beginning January 1, 1975

F.P.C. Opinion No.: 749

Date Issued: December 31, 1975

Definitions of "old" gas: Sales of natural gas in interstate commerce for resale from a well or wells commenced prior to January 1, 1973.

Applicable Rate: 23.5¢/Mcf prior to July 1, 1976; 29.5¢/Mcf on and after July 1, 1976. (This rate does not supercede existing higher area rates nor other specified F.P.C. established rates.)

TABLE 1 (continued)

F.P.C. NATIONAL RATE RULINGS

F.P.C. Opinion No.:	770
Date Issued:	July 27, 1976
Definitions of "new" gas:	(1) Sales of natural gas in interstate commerce for resale from a well or wells commenced on or after January 1, 1975. (2) The sale is made pursuant to a contract for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce prior to January 1, 1975 (except under specified F.P.C. certificates), where the sale is initiated on or after January 1, 1975, provided that no certificate for the subject sale has been issued under the optional procedure.
Applicable Rate:	$1.42/Mcf and 1¢/Mcf per quarter commencing October 1, 1976
Definitions of 1973-1974 gas:	(1) Sales of natural gas in interstate commerce for resale made from a well or wells commenced on or after January 1, 1973 and on or before January 1, 1975. (2) The sale is made pursuant to a contract for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce on or after January 1, 1973 (except under specified F.P.C. certificates), where the sale is initiated before January 1, 1975.
Applicable Rate:	$1.01/Mcf

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TABLE 1 (continued)

F.P.C. NATIONAL RATE RULINGS

F.P.C. Opinion No.:	770-A
Date Issued:	November 5, 1976
Definitions of "new" gas:	Sales of natural gas in interstate commerce for resale from a well commenced on or after January 1, 1975.
Applicable Rate:	$1.42/Mcf and 1¢/Mcf per quarter escalation beginning October 1, 1976.
Definitions of 1973-1974 gas:	Sales of natural gas in interstate commerce for resale made from a well commenced on or after January 1, 1973 and prior to January 1, 1975.
Applicable Rate:	93¢/Mcf and 1¢/Mcf annual escalation beginning January 1, 1977

(NOTE: IN BOTH OF THE ABOVE DEFINITIONS, WELL DATE IS DEFINED AS COMMENCEMENT OR SPUD-IN DATE REGARDLESS OF DATE OF COMPLETION OR RECOMPLETION.)

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ROYALTY OIL ISSUES

February 1978

Alaska Oil & Chemical Company

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INTRODUCTION

In response to the State of Alaska's request, Alaska Oil & Chemical Company (AOC) and other potential purchasers have submitted contracts to the Commissioner of Natural Resources for the purchase of a portion of the State of Alaska's Prudhoe Bay Unit royalty oil. As a part of the solicitation, the potential purchasers received a policy statement containing eight guidelines.

The bidding procedure followed has not created any forum under which the merits of the various proposals or the applicability of the various guidelines could be examined. Therefore, AOC has prepared the attached report for the assistance of the Royalty Oil and Gas Development Advisory Board and anyone else interested in the wise use of Alaska's Prudhoe Bay royalty oil.

The underlying issues are examined in what AOC believes is a logical sequence starting with the availability of Prudhoe Bay royalty oil. Following the examination of these issues, AOC's plan, the cost thereof to the State, and the potential benefits to the State are discussed.

ISSUES

1. DOES THE STATE HAVE ENOUGH ROYALTY OIL TO SUPPORT ANY OF THE PROPOSED PROJECTS?

No "official" forecasts of Prudhoe Bay royalty oil production were supplied with the bid request. However, the State made available the Van Poolen report and suggested AOC use Case 3A. The State has also stipulated that it will not commit more than 85% of its 12.5% royalty. Figure 1 opposite shows the Van Poolen forecast of total oil production, royalty oil and 85% of the royalty oil.

This forecast indicates that the royalty oil available will drop below AOC's 100,000 barrels per day (B/D) requirement in the seventh year. Therefore, other forecasts were sought and 85% of the royalty oil indicated in such forecasts is shown below, and graphically on Pages 4, 5 and 6.

Plant Year	Calendar Year	Van Poolen Case 3A	Dept. Nat. Resources		AOC	Confid Info	FPC Filings		
			Reasonable	Conserv			Mobil	Arco	Sohio
1	1983	159.4	159.4	123.3	159.4	159.4	159.4	159.4	159.4
2	1984	159.4	159.4	123.3	159.4	159.4	159.4	159.4	159.4
3	1985	159.4	159.4	123.3	159.4	159.4	159.4	157.8	159.8
4	1986	159.4	159.4	123.3	150.5	148.2	106.3	136.0	127.5
5	1987	142.8	159.4	123.3	142.2	137.9	106.3	108.4	127.5
6	1988	122.4	132.4	123.3	134.4	128.2	-	95.6	-
7	1989	117.3	111.1	123.3	127.3	119.2	-	-	-
8	1990	81.3	95.6	123.3	118.2	110.9	-	-	-
9	1991	58.3	64.1	123.3	110.0	103.1	-	-	-
10	1992	46.6	-	98.7	102.3	95.9	-	-	-
11	1993	38.0	-	64.3	95.1	89.2	-	-	-
12	1994	49.0	-	-	88.5	83.0	-	-	-
13	1995	47.6	-	-	82.3	77.1	-	-	-
14	1996	38.5	-	-	76.6	71.7	-	-	-
15	1997	29.2	-	-	71.2	66.7	-	-	-

It is apparent that even the most optimistic projections (DNR-Conservative, AOC and Confidential) indicate that after about the ninth year less than 100,000 B/D will be available. Therefore, AOC concludes the optimum size facility should not exceed 100,000 B/D and that financing of anything larger without State assistance will be difficult.

FIGURE 1

VAN POOLEN REPORT
CASE 3A
PRUDHOE BAY UNIT

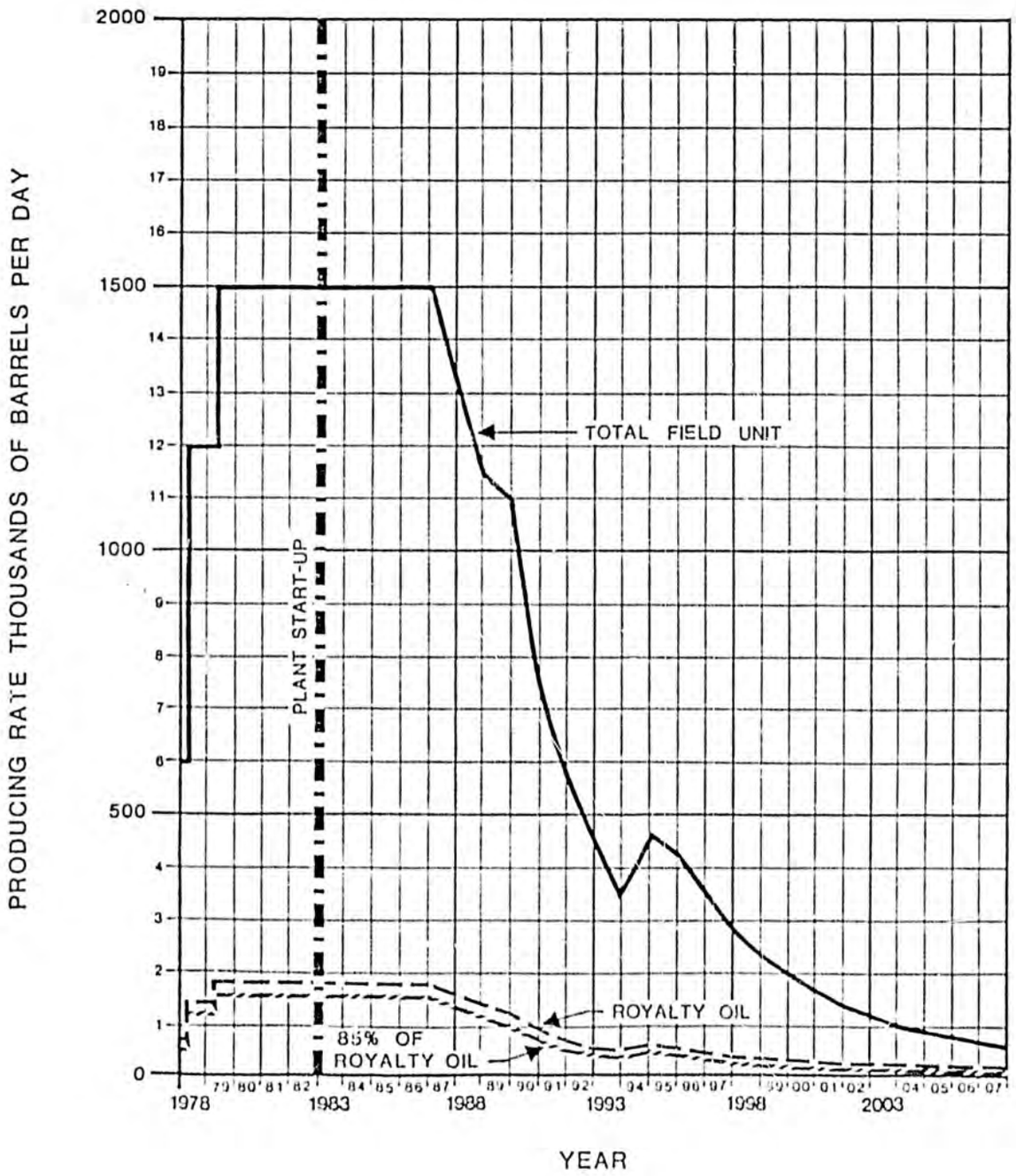

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FIGURE 2

VAN POOLEN AND DEPARTMENT OF NATURAL RESOURCES FORECASTS

85% OF PRUDHOE BAY ROYALITY OIL

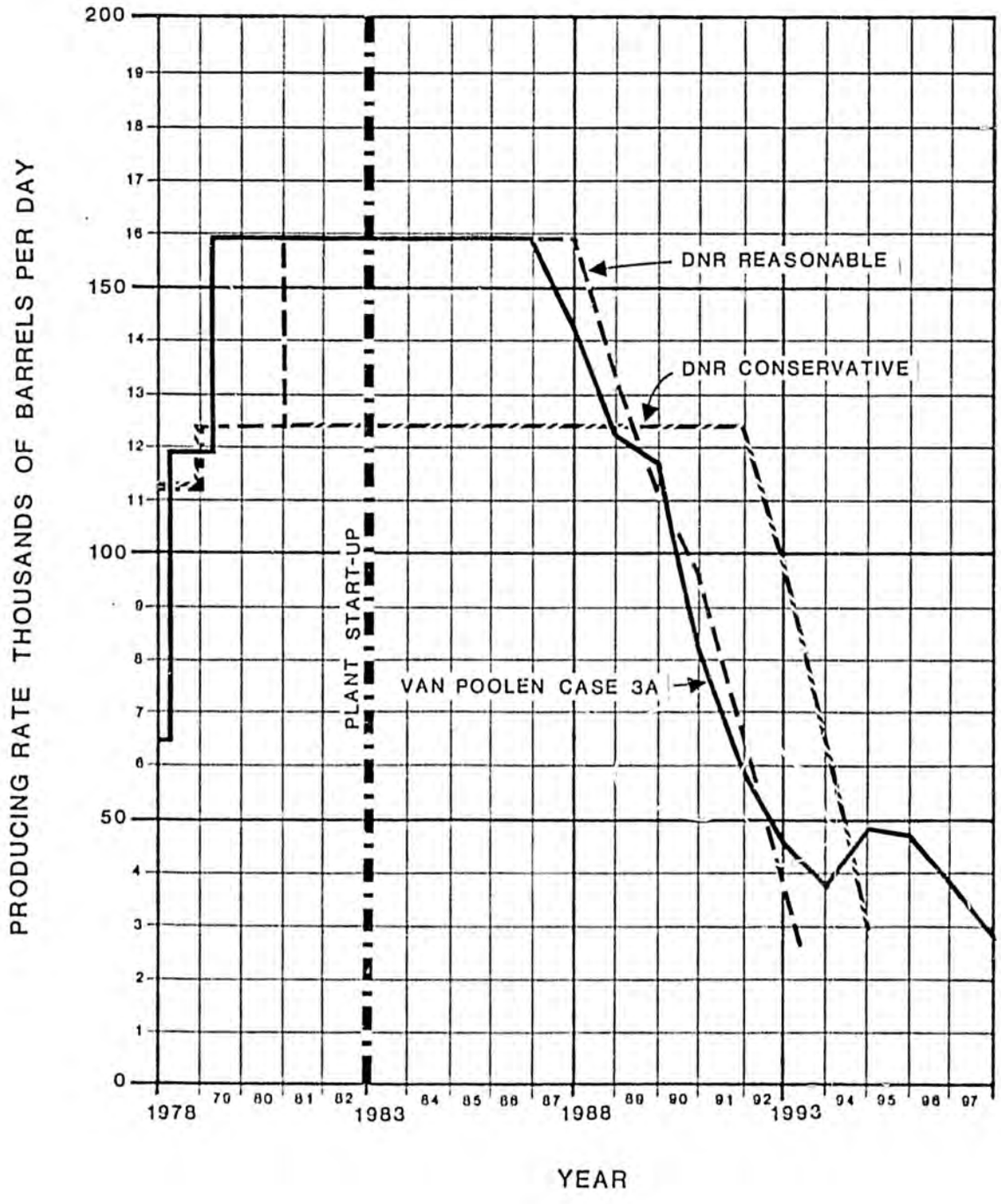

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FIGURE 3

VAN POOLEN, AOC AND CONFIDENTIAL FORECASTS

85% OF PRUDHOE BAY ROYALTY OIL

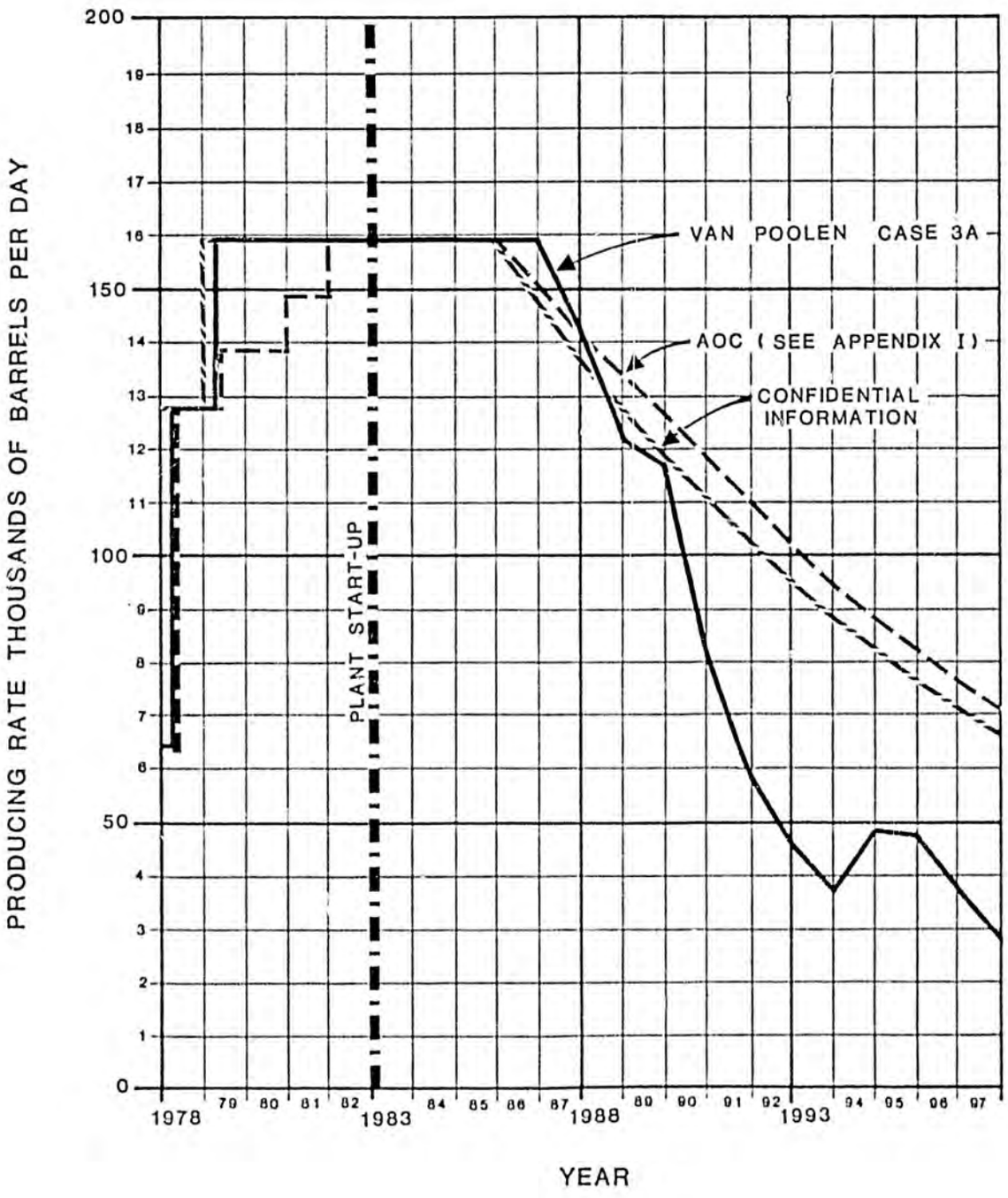

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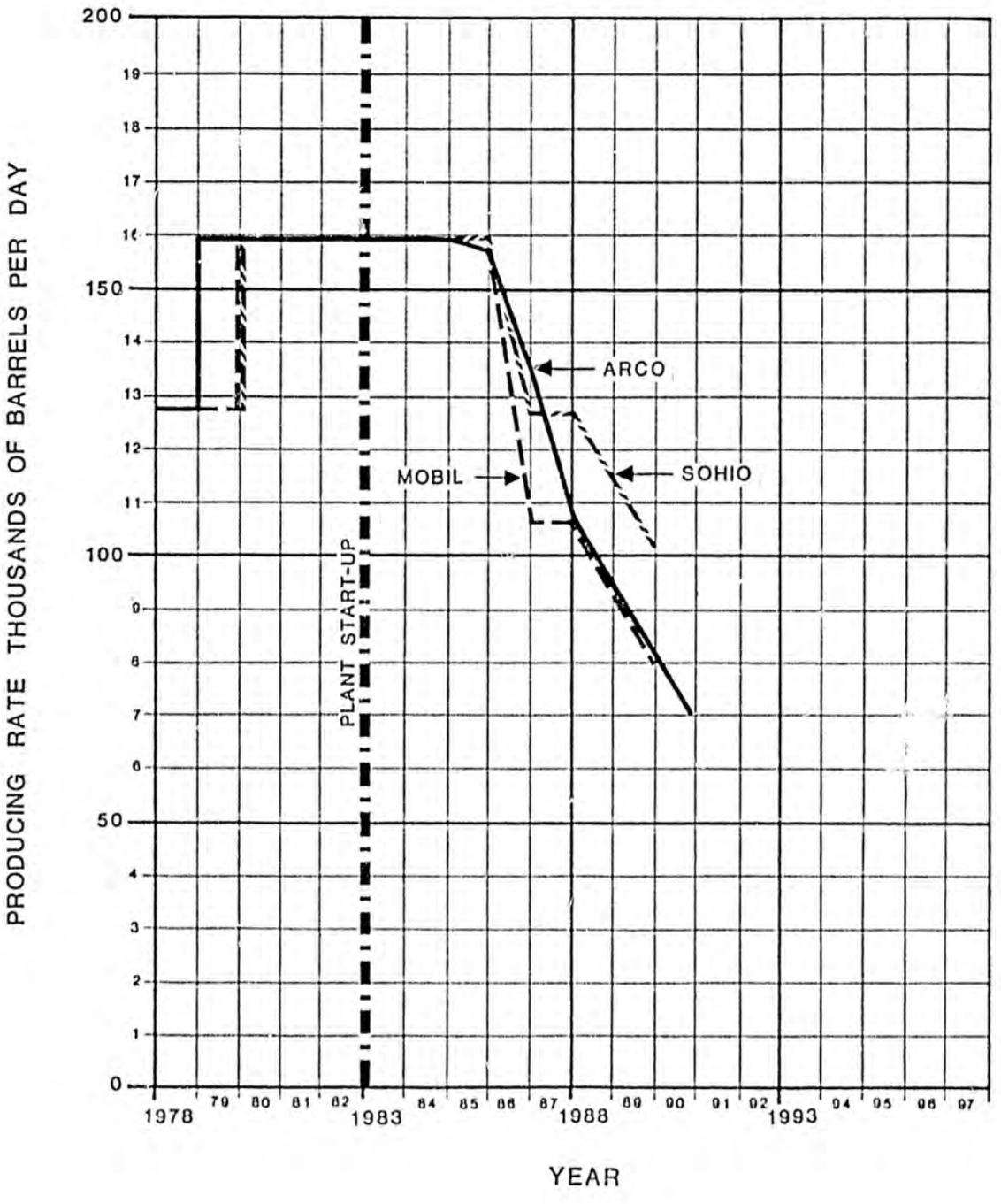
FIGURE 4

ARCO, SOHIO AND MOBIL FPC FORECASTS

85% OF PRUDHOE BAY ROYLTY OIL



Unfortunately, neither the Bonner & Moore Associates, Inc. (Bonner & Moore) report nor the Smith Barney, Harris Upham & Co. (Smith Barney) report consider this fundamental limitation. However, in fairness, Bonner & Moore was instructed to develop economics using 1.2 and 1.8 million B/D of North Slope crude and Smith Barney was not called upon to determine the project feasibility.

Specifically, Bonner & Moore determined their "Deemed Economic Price" on the basis of a 16-year life (see pages 3-4 and 3-5 of the Bonner & Moore report). This means their economics are valid if the facilities operate at rated capacity for 16 years. It is obvious that if the available oil is less than the rated capacity the unit costs for at least the capital related items must increase.

To assist the Royalty Board in weighing these proposals, AOC has recalculated the Capital-Related Charges developed by Bonner & Moore to reflect the effect on the "Deemed Economic Price" if only the most optimistic forecast (AOC's) of Prudhoe Bay royalty oil is processed in the proposed facility. These economics are developed in Appendix II and are summarized below.

	ALPETCO		Petrofining		APC	
	At Rated Capacity 150 MB/D	Available Royalty Oil 111.8 MB/D	At Rated Capacity 250 MB/D	Available Royalty Oil 115 MB/D	At Rated Capacity 150 MB/D	Available Royalty Oil 111.8 MB/D
Deemed Economic Price	7.10	2.88	6.85	4.70	6.26	5.51
In-Value	6.33	6.33	6.33	6.33	6.33	6.33
Premium (Debit)	0.77	(3.45)	0.52	(1.63)	(0.07)	(0.82)

Based on the foregoing, AOC suggests that the Royalty Board seriously consider whether its best interests are served by inducing any company to expend large sums of money in pursuing an in-State refining venture, or whether a more modest endeavor, such as proposed by AOC, is appropriate.

2. HOW SHOULD ALASKA USE THIS SHORT-TERM BONANZA?

The options are:

a. Take the maximum current revenue in the form of "in-value" payments, or

b. Use the royalty oil to establish an industry which will be viable after Prudhoe Bay declines.

Nothing AOC has been able to develop during the bidding process, or has seen in the contracts proposed by others, indicates that an in-State facility can, initially at least, assure the State as much money as if it took its royalty in money. Notwithstanding, AOC believes that the wisest course for the State is to examine carefully the possibility of committing a reasonable portion of its royalty oil to an in-State processing facility. Such commitment should be carefully constructed so that the purchaser has strong economic incentives to maximize the delivery point value of the royalty oil.

However, it would be presumptuous of AOC or any applicant to make the final decision for the State if there is any likelihood that there will be a long-term cost associated with such decision. Thus, AOC has tailored its proposal to provide continuous participation by the State in the decision making.

3. SHOULD THE STATE ENCOURAGE THE ESTABLISHMENT OF:

(A) A FUELS REFINERY, OR (B) A PETROCHEMICAL REFINERY?

Two types of facilities - fuels refineries or petrochemical refineries, have been proposed. AOC has examined both possibilities and feels the State should take into consideration the following factors:

1. In either case, products must very largely be exported from Alaska. While a new fuels refinery could be expected to capture a portion, at least, of the growth in local demand, AOC does not believe this benefits the State. There is already sufficient competition in the State and adding another refinery does not assure lower fuel costs. Actually, Alaskans would benefit if the existing refineries could expand and therefore have lower unit costs.

2. On the other hand, a petrochemical refinery will add a new dimension to Alaska's economic life. It will enable Alaskans to more clearly control their destiny and, as indicated previously, would provide a nucleus for future development when Prudhoe Bay declines. Unlike a refinery which must compete head on with refined products produced in Alaska, on the West Coast or Hawaii from existing or expanded refineries, petrochemicals destined for the West Coast have a natural niche since most of them are currently produced on the Gulf Coast and shipped to the West Coast. AOC has never underestimated the difficulties in establishing a petrochemical refinery in Alaska. On the contrary, AOC has consistently pointed out the difficulties. No one will know, however, whether a facility is viable until the State commits for a period of time its oil to one responsible experienced group to endeavor to

find out the true economics of producing petrochemicals. Once this is established the State can determine the cost/benefit of such venture. Only AOC has consistently proposed such an approach.

4. SHOULD THE STATE MAKE A FINAL DECISION NOW?

AOC believes that the bidding process which is being completed has served a very useful purpose in bringing into focus these various issues. Conspicuous by their absence from any of the bidding have been any of the petrochemical companies or major refining companies. AOC submits that the guideline of "no less than in-value" virtually precludes offering the economic incentive required to establish either a refinery or petrochemical plant in Alaska given the added costs of building, owning and operating a facility in Alaska. None of the proposals irrevocably demonstrated that they can meet this guideline. This should speak volumes to the Board and to the legislature.

AOC has consistently attempted to deal constructively with this issue rather than play games trying to meet an unrealistic guideline. In simplest terms it proposes to do all the work necessary to provide the State with the necessary information on which the State can base a final decision. The decision itself is left totally with the State. AOC thinks this is the only practical approach to take and that in the final analysis, regardless of which proposal is accepted, the State will have to exercise such judgment. Why not do it in a businesslike, well-organized way with an experienced and competent consortium in which experienced Alaskans are full partners?

5. ARE THE GUIDELINES SET FORTH IN THE BOARD'S POLICY STATEMENT REALISTIC?

AOC submits that the bidding process has demonstrated that two of the guidelines in the Policy Statement are unrealistic and should be revised. AOC has no quarrel with guidelines (3) through (8). However, (1) and (2), although worthy targets, appear to be mutually exclusive - at least in the short term. AOC firmly believes that a fair "bottom line" evaluation of net benefits to present and future generations of Alaskans will conclusively demonstrate that a petrochemical refinery will produce long term net benefits. However, AOC likewise believes that the ramifications of the State's inducing establishment of such new industry are so widespread that the final decision should be retained by the State.

AOC fully accepts that the net benefits to the State must be the controlling judgment factor. However, it believes the State should not arbitrarily impose the guideline of in-value. Rather, it should be used as a test of the net benefits.

AOC'S PLAN

AOC proposes an orderly, businesslike approach to determine the minimum incentives that would be required to induce purchasers to buy the output of the petrochemical refinery and/or build satellite downstream plants in Alaska. To do this, the State is asked to make three commitments. First, the State must accept a minimum cost formula that assures financibility of the plant. Second, it must designate a plant site. Third, agree to make a "go, no go" decision by a date certain.

With these factors established, AOC will, at its sole cost and expense, obtain offtake and construction contracts through the process of soliciting competitive proposals. AOC will also perform, at its sole cost and expense, detailed engineering and economic forecasts. Such work is to be completed in 12 months. AOC's complete staff and files will be available to the State during this time and the State is invited to participate to the extent the State deems appropriate in this process.

During the next six months the State will prepare its own Cost/Benefit Analysis and within two additional months reach its decision on the desirability of implementing the previously negotiated contracts. AOC will assist the State in such analysis, but the decision will rest with the State.

If the State decides it wishes AOC to proceed, the contracts will be implemented. If the State decides <u>not</u> to require AOC to proceed, AOC will have the option to purchase a limited quantity of oil.

WHAT DOES AOC'S PLAN COST THE STATE?

1. An agreement not to commit 100,000 B/D or up to 85% of its royality oil for a maximum period of two years.

2. Such loss, if any, the State deems appropriate to take upon completion of its cost/benefit analysis.

3. Any costs incurred by the State in the preparation of its cost/benefit analysis. (Such costs are totally within the State's power to control.)

4. The granting of an option to AOC to purchase at in-value up to 40,000 B/D of oil only if:

   (a) the State cancels the contract, or

   (b) the State, having completed its cost/benefit analysis, decides not to have AOC proceed with the construction of the facilities. Such option contract not to have a term in excess of ten years from the date of the basic agreement.

WHAT ARE THE POTENTIAL BENEFITS OF AOC'S PLAN?

AOC has recognized from the beginning that asking the State to assume the risk of not receiving the alternate or "in-value" means AOC is not entitled to more profit than required to attract the necessary capital. At the same time, AOC is very cognizant that the State would be ill-advised to guarantee a financible project unless AOC had substantive incentives to maximize the price the State receives for its royalty oil. Thus, AOC has developed a cost-of-service approach with specific incentives in the form of increased return to AOC based solely on the price the State gets for the royalty oil sold to AOC. Therefore, at all times AOC has a strong incentive to maximize the return to the State. This formula and illustrative examples are discussed in the following section of this report.

In addition to a minimum cost operation where AOC has strong economic incentives to maximize the State's revenue, AOC recognizes that at some point in time the petrochemical refinery will have spare capacity. This capacity will have been underwritten by the basic contract to process Prudhoe Bay royalty oil. Therefore, AOC is prepared to share equally this surplus capacity with the State. Since, as illustrated in the next section, this will most likely occur when the depreciation component of the formula has been eliminated, this could result in the State having extremely cheap capacity available for new oil just when Prudhoe Bay oil production is declining rapidly.

HOW DOES AOC'S PROCESSING FEE FORMULA WORK?

PROCESSING FEE (Article VII of AOC's Proposed Contract)

The processing fee is designed to provide the maximum net revenue to the State consistent with AOC being able to finance. It has built into it incentives to maximize the State's net revenue. The individual components are:

A. OPCST = Operating Costs. These are fixed and variable operating costs incurred by AOC and include transportation from Prudhoe Bay to the core petrochemical refinery and direct operating costs therein. Since there is no profit involved, it is to the mutual advantage of the State and AOC to minimize such costs.

B. DEPR = Depreciation. This charge returns the fixed investment to the investors, both debt and equity. AOC proposes it be tied to the average term of the sales contracts. AOC believes these terms will be determined by the reserves committed to the project which AOC's figures indicate will be about ten years after the refinery starts up. Of course, AOC would be prepared to extend the depreciation period provided the State can assure AOC and, more importantly, the offtake purchasers that the oil will be available. Such extension obviously would reduce the processing fee and benefit both AOC and the State.

C. INT = Interest. This charge merely returns actual interest costs. Therefore, it is obviously in the mutual interest of AOC and the State to minimize these costs.

D. INC TAX = Actual Income Tax. This charge merely covers the taxes AOC, as

a profit-making entity, must pay. AOC is well aware that Internal Revenue Service regulations permit investment tax credits, accelerated depreciation, etc. in computing income taxes. The effect of these is illustrated in the tables discussed below.

E. RETURN = Return on Capital Employed. AOC chose a variable return to demonstrate conclusively AOC's intention of maximizing the value of Prudhoe Bay royalty oil. The minimum return is that required to obtain the debt and equity. In the event the State is receiving less than in-value, AOC's return is the minimum 15% required to attract the debt and equity capital. When the State receives more than in-value AOC gets an increased return up to 20%. In the event the State is getting in-value and AOC is getting 20%, then AOC will get 10% of any additional revenue and the State will get 90%. In no case will the State have to pay AOC.

ILLUSTRATIVE EXAMPLES

AOC has developed three examples to illustrate how its proposed formula would work over a 15-year period.

Tables I and I-A are based on AOC's Probable Forecast.

Table II is based on Van Poolen's Case 3A.

Tables III and III-A are based on full plant operation.

In each case the plant is assumed to cost $1 billion and be capable of operating 350 days per year. Operating costs have been estimated at $50 million per year. It has been assumed that the debt, $800 million, would be retired in equal instalments and bear interest at 9%.

For simplicity, it has been assumed that the gross sales revenue less the in-value is $7.50/B of oil purchased. AOC believes this is in the

range for the assumed configuration of the plant.

Table I opposite illustrates the operation of the formula if only AOC's Probable Forecast volume of oil is processed and no accelerated depreciation or investment tax credit is taken. It is included to illustrate the principles of the formula.

The top two lines show the forecast of the field production and the resultant royalty oil. The next three lines indicate the disposition of this oil. As the note indicates, the refinery runs 100,000 B/D for 350 days per year, or 85% of the State's royalty oil, whichever is less. It should be noted this assumes the refinery would have sufficient crude oil storage in the declining years to take the royalty oil every day.

The next three lines show the sources of the refinery feed. For this example no other feed is expected.

The gross difference is the $7.50/B multiplied by the number of barrels processed.

The Deductions are per the contract as noted above. It can be seen that in the first three years the Deductions exceed the Gross Difference, which means the State would be getting less than in-value. Thus, the State is suffering a debit and, of course, AOC only gets its minimum return. In Years 3 and 4 the Gross Difference exceeds the minimum Deduction so the State gets its in-value and AOC gets slightly more than the minimum. This change occurs because the interest payments are going down.

By the sixth year the Gross Difference exceeds the Deductions and the State moves into the Premium position.

The State gets an increased premium which rapidly accelerates when

TABLE I

ALASKA OIL & CHEMICAL COMPANY

PROBABLE FORECAST

SALES LESS IN-VALUE = $7.50/bbl.

(Thousands of Dollars Unless Otherwise Noted)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1983-1992 (1-10)	1993	1994	1995	1996	1997	Total to Average	%
[illegible]																		
[illegible]	1,500.0	1,500.0	1,500.0	1,416.0	1,338.0	1,265.0	1,198.0	1,114.0	1,035.0	963.0	1,282.9	895.0	833.0	775.0	721.0	670.0	1,114.9	-
[illegible]	187.5	187.5	187.5	177.0	167.3	158.1	149.8	139.3	299.4	120.4	160.4	111.9	104.1	96.9	90.1	83.8	139.4	-
[illegible]																		
[illegible]	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	350.0	34.7	32.3	30.1	28.0	26.0	501.1	65.7
[illegible]	33.4	33.4	33.4	29.6	26.1	22.7	19.7	15.8	12.2	8.9	235.2	6.1	5.7	5.3	4.9	4.6	261.8	34.3
Total	68.4	68.4	68.4	64.6	61.1	57.7	54.7	50.8	47.2	43.9	585.2	40.8	38.0	35.4	32.9	30.6	762.9	100.0
[illegible]																		
[illegible]	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	350.0	34.7	32.3	30.1	28.0	26.0	501.1	100.0
[illegible]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0
Total	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	350.0	34.7	32.3	30.1	28.0	26.0	501.1	100.0
[illegible]	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	2,625,000	260,250	242,250	225,750	210,000	195,000	3,758,250	-
[illegible]																		
[illegible]	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	500,000	50,000	50,000	50,000	50,000	50,000	750,000	-
[illegible]	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	1,000,000	-	-	-	-	-	1,000,000	-
[illegible]	60,200	61,200	55,000	46,800	39,600	32,400	25,200	18,000	10,800	3,600	360,000	-	-	-	-	-	360,000	-
[illegible]	30,000	30,000	30,000	32,850	36,450	40,000	40,000	40,000	40,000	40,000	359,300	40,000	40,000	40,000	40,000	40,000	559,300	-
[illegible]	30,000	30,000	30,000	32,850	36,450	40,000	40,000	40,000	40,000	40,000	359,300	40,000	40,000	40,000	40,000	40,000	559,300	-
Total	278,400	271,200	264,000	262,500	262,500	262,400	255,200	248,000	240,800	233,600	2,578,600	130,000	130,000	130,000	130,000	130,000	3,228,600	-
[illegible]	(15,900)	(8,700)	(1,500)	-	-	100	7,300	14,500	21,700	28,900	46,400	130,250	112,250	95,750	80,000	65,000	529,650	-
[illegible]	(0.[illegible])	(0.252	(0.04)	-	-	-	0.21	0.41	0.62	0.83	0.13	3.75	3.48	3.18	2.86	2.50	1.06	

Note: [illegible] 100,000 B/D or [illegible] of Alaska's Royalty Oil, whichever is less.

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the interest and depreciation terms of the formula are extinguished. However, this is just when the volumes available begin to fall off so, while the unit premiums are high, the average over the life is $1.06/B. This clearly illustrates the effect on the viability of any surplus capacity. Put another way, the State and AOC have a strong incentive to keep the petrochemical refinery full as long as possible.

While the preceeding Table, Table I, clearly illustrates the working of the contract, it does not take into account the benefits which would accrue to the State and AOC of taking maximum advantage of accelerated depreciation and investment tax credit. Table I-A opposite illustrates the same case taking advantage of maximum tax depreciation and investment tax credit.

It can be seen that all the numbers down through Gross Difference are identical. However, the combination of accelerated depreciation and income tax credit reduce the taxes for the first six years so the State is not in a Debit position. However, after the seventh year the taxes jump up when the investment tax credit has run out and the depreciation is getting low and the State moves into a Debit position.

It should be noted that, while investment tax credits reduce taxes, rapid depreciation merely changes the timing on when the taxes are paid. The net overall effect is a rearrangement of the Premium and Debits and a slight increase in the Premium due to the operation of the investment tax credit.

TABLE I-A

ALASKA OIL & CHEMICAL COMPANY

PROBABLE FORECAST - MINIMUM TAX

SALES LESS IN-VALUE = $7.50/BBL.

(Thousands of Dollars Unless Otherwise Noted)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1983-1992 (1-10)	1993	1994	1995	1996	1997	Total to Average	%
[illegible]	1,500.0	1,500.0	1,500.0	1,416.0	1,338.0	1,265.0	1,198.0	1,114.0	1,035.0	963.0	1,262.9	895.0	833.0	775.0	721.0	670.0	1,114.9	-
[illegible]	187.5	187.5	187.5	177.0	167.3	158.1	149.8	139.3	299.4	120.4	160.4	111.9	104.1	96.9	90.1	83.8	139.4	-
[illegible]	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	350.0	34.7	32.3	30.1	28.0	26.0	501.1	65.7
[illegible]	33.4	33.4	33.4	29.6	26.1	22.7	19.7	15.8	12.2	8.9	235.2	6.1	5.7	5.3	4.9	4.6	261.8	34.3
[illegible]	68.4	68.4	68.4	64.6	61.1	57.7	54.7	50.8	47.2	43.9	85.2	40.8	38.0	35.4	32.9	30.6	762.9	100.0
[illegible]	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	350.0	34.7	32.3	30.1	28.0	26.0	501.1	100.0
[illegible]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0
[illegible]	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	350.0	34.7	32.3	30.1	28.0	26.0	501.1	100.0
[illegible]	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	2,625,000	260,250	242,250	225,750	210,000	195,000	3,758,250	-
[illegible]	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	500,000	50,000	50,000	50,000	50,000	50,000	750,000	-
[illegible]	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	1,000,000	-	-	-	-	-	1,000,000	-
[illegible]	60,000	61,200	55,000	46,800	32,600	32,400	25,200	18,000	10,800	3,600	360,000	-	-	-	-	-	360,000	-
[illegible]	-	-	14,000	23,500	30,500	36,500	42,000	82,000	90,000	96,000	413,500	10,000	10,000	11,000	40,000	40,000	[illegible]	-
[illegible]	40,000	40,000	40,000	40,000	40,000	40,000	40,000	30,000	30,000	30,000	320,000	40,000	40,000	40,000	40,000	40,000	520,000	-
[illegible]	250,500	251,200	257,000	260,300	260,100	258,900	257,200	280,000	280,800	279,600	2,643,500	100,000	100,000	101,000	130,000	130,000	3,2[illegible],500	
[illegible]	5,100	31,300	5,500	2,200	2,400	3,600	5,300	(17,500)	(18,300)	(17,100)	(18,500)	160,250	142,250	124,750	80,000	65,000	553,250	-
[illegible]	.1[illegible]	.32	.16	.06	.02	.10	0.15	(.50)	(.52)	(.49)	(.05)	4.62	4.40	4.14	2.86	2.50	1.11	

[illegible] Alaska's Royalty Oil, whichever is less.

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Table II opposite has been included to reflect the operation of the formula based on the Van Poolen report Case 3A. Because of the very rapid drop off in available oil beginning in 1990, the State moves back into a Debit position that year. If, indeed, the final contracts and anticipated oil deliveries indicate Debits of this magnitude, the State would have to find offsetting factors such as job opportunities, diversification, etc., before it could decide it wants AOC to proceed.

For the reasons set forth in Appendix I, AOC does not believe the Van Poolen report fully reflects the oil availability. However, it believes the State should exercise that judgment when the final information is available.

TABLE II

ALASKA OIL & CHEMICAL COMPANY

VAN POOLEN REPORT FORECAST

SALES LESS 10% VALUE = $7.50/BBL.

(Thousands of Dollars Unless Otherwise Noted)

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1983-1992	1993	1994	1995	1996	1997	Total In Average	%
	1	2	3	4	5	6	7	8	9	10	(1-10)	11	12	13	14	15		
Oil Production, M/B																	
Proven Developed	1,500.0	1,500.0	1,500.0	1,500.0	1,444.0	1,252.0	1,104.0	265.0	559.0	439.0	11,353.0	358.0	561.0	448.0	362.0	275.0	881.9	
Gross Royalty Oil	187.5	187.5	187.5	187.5	168.0	144.0	138.0	95.6	68.6	54.9	1,419.1	44.8	57.6	56.0	45.3	33.4	110.5	
Net Oil Available, M/B																		
Proven Developed	35.0	35.0	35.0	35.0	35.0	35.0	35.0	29.7	21.1	17.0	313.0	13.9	17.9	17.4	14.0	10.7	396.9	64.0
Royalty	33.5	33.5	33.5	33.5	26.3	17.6	13.4	5.2	3.7	3.5	204.8	2.5	3.1	3.0	2.5	1.9	217.8	36.0
Total	68.5	68.5	68.5	68.5	61.3	52.6	48.5	34.9	24.8	20.6	517.8	16.4	21.0	20.5	16.5	12.6	614.7	100.0
Gross Revenue, $/Yr. (Before Deductions)	262,500	262,500	262,500	262,500	262,500	262,500	227,850	159,750	127,500	2,357,500	104,250	114,250	110,500	105,000	80,250	2,001,250		
Deductions																		
Operating Cost	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	500,000	50,000	50,000	50,000	50,000	50,000	350,000	
Depletion	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	1,000,000	-	-	-	-	-	1,000,000	
Royalty	33,500	33,500	33,500	33,500	26,300	17,600	13,500	9,500	1,600	1,600	360,000	-	-	-	-	-	360,000	
Income Tax	10,000	10,000	10,000	12,850	16,450	50,000	50,000	50,000	40,000	40,000	359,300	40,000	40,000	40,000	40,000	50,000	359,300	
Reserve	15,000	15,000	15,000	15,000	16,450	50,000	50,000	50,000	40,000	40,000	359,300	50,000	50,000	50,000	50,000	40,000	359,300	
Total Ded.	208,500	208,500	208,500	211,350	209,200	267,600	263,500	259,500	231,600	231,600	2,578,600	140,000	140,000	140,000	140,000	140,000	1,378,600	
Income (Loss)	(15,500)	(8,000)	(1,500)	-	-	100	(1,300)	(25,250)	(81,850)	(106,100)	(231,100)	(25,750)	5,250	500	(25,000)	(49,750)	(326,850)	
Income (Loss) Per Unit	(0.44)	(0.23)	(0.04)	-	-	-	(.21)	(0.85)	(3.93)	(6.24)	(0.75)	(1.85)	0.24	0.03	(1.79)	(3.95)	(0.84)	

Note: All Net Revenue Interest is Alaska Crude Oil, Wholesale Price

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Tables III opposite and III-A, overleaf, illustrate the operation of the formula if the State and AOC are able to keep the petrochemical refinery operating at full capacity for 15 years. It is assumed that the Van Poolen volumes would be supplemented by other compatible oil sources so that the petrochemical refinery would operate at full capacity.

Such full capacity operation has a marked effect on the Premium received by the State. Table III has been included to illustrate the operation of the formula. It should be compared to Table I. It will be noted that just filling up the refinery from 501.1 million barrels of oil to 525.0 million barrels increases the premium from $1.06 to $1.35/B for all oil processed.

Table III-A uses the same basis but allows for the effects of rapid depreciation and investment tax credit.

It should be noted that none of these tables illustrates the incentive AOC has to improve the profitability further once the State, on a cumulative basis, gets its in-value. AOC and the State share 10% and 90%, respectively in such Premium.

TABLE III

ALASKA OIL & CHEMICAL COMPANY

FULL CAPACITY OPERATION

SALES LESS IN-VALUE = $7.50/BBL.

(Thousands of Dollars Unless Otherwise Noted)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1983-1992	1993	1994	1995	1996	1997	Total To Average	
	1	2	3	4	5	6	7	8	9	10	(1-10)	11	12	13	14	15		
Oil Production, MB/D																		
Produce Bay Field	1,500.0	1,500.0	1,500.0	1,344.0	1,152.0	1,104.0	765.0	559.0	439.0	358.0	10,211.0	461.0	448.0	362.0	275.0	238.0	799.7	
Alaska's Royalty Oil	197.5	187.5	187.5	168.0	144.0	138.0	95.6	68.6	54.9	44.8	1,276.4	57.6	56.0	45.3	34.4	29.8	100.0	
Royalty Oil Disposition, MMBbls.																		
A.O.C. Petrochemical Refinery(1)	35.0	35.0	35.0	35.0	35.0	35.0	29.7	21.3	17.0	13.9	291.9	17.9	17.4	14.1	10.7	9.2	361.2	68.8
Otherwise	33.4	33.4	33.4	26.3	17.6	15.4	5.2	3.7	3.0	2.5	173.9	3.1	1.0	2.4	1.9	1.2	186.0	35.0
Total	68.4	68.4	68.4	61.3	52.6	50.4	34.9	25.0	20.0	16.4	465.8	21.0	20.4	16.5	12.6	10.9	547.2	100.0
A.O.C. Petrochemical Refinery Feed																		
Produce Bay Royalty Oil MMBbl.	35.0	35.0	35.0	35.0	35.0	35.0	29.7	21.3	17.0	13.9	291.9	17.9	17.4	14.1	10.7	9.2	361.2	68.8
Other Oil	0.0	0.0	0.0	0.0	0.0	0.0	5.3	13.7	18.0	21.1	58.1	17.1	17.6	20.9	24.3	25.8	163.8	31.2
Total	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	350.0	35.0	35.0	35.0	35.0	35.0	525.0	100.0
Gross Difference	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	2,625,000	262,500	262,500	262,500	262,500	262,500	1,937,500	
Deductions																		
Operating Costs	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	500,000	50,000	50,000	50,000	50,000	50,000	750,000	
Depreciation	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	1,000,000	-	-	-	-	-	1,000,000	
Interest	68,400	61,200	54,000	46,800	39,600	32,400	25,200	18,000	10,800	3,600	360,000	-	-	-	-	-	360,000	
Income Tax	40,000	40,000	40,000	32,850	36,450	40,000	40,000	40,000	40,000	40,000	359,300	40,000	40,000	40,000	40,000	40,000	559,300	
Return	40,000	40,000	40,000	32,850	36,450	40,000	40,000	40,000	40,000	40,000	359,300	40,000	40,000	40,000	40,000	40,000	559,300	
Subtotal	278,400	271,200	264,000	262,500	262,500	262,400	255,200	248,000	240,800	233,600	2,578,600	130,000	130,000	130,000	130,000	130,000	3,228,600	
Premium (Debit)	(15,900)	(8,700)	(1,500)	-	-	100	7,300	14,500	21,700	28,900	46,400	132,500	132,500	132,500	132,500	132,500	708,900	
Premium (Debit) $ per Bbl.	(0.45)	(0.25)	(0.04)	-	-	-	0.21	0.41	0.62	0.83	0.13	3.79	3.79	3.79	3.79	3.79	1.35	

Note: (1) 100,000 B/D or 85% of Alaska's Royalty Oil, whichever is less.

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TABLE III-A

ALASKA OIL & CHEMICAL COMPANY

FULL CAPACITY OPERATION - MINIMUM TAX

SALES LESS IN-VALUE = $7.50/BBL.

(Thousands of Dollars Unless Otherwise Noted)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001-2010	2011	2012	2013	2014	2015	Total To Abandonment	%
	1	2	3	4	5	6	7	8	9	10	(1-10)	11	12	13	14	15		
Oil Production, MB/D																		
Taxable Oil Field	1,500.0	1,500.0	1,500.0	1,354.0	1,152.0	1,104.0	765.0	559.0	439.0	358.0	10,211.0	461.0	448.0	362.0	225.0	238.0	294.2	
Non-Taxable Royalty Oil	187.5	187.5	187.5	168.0	144.0	138.0	95.6	69.6	54.9	44.8	1,276.4	57.6	56.0	45.3	28.4	29.8	368.0	
Taxable Oil Disposition, MMBBL																		
Field Extraction of Refinery Fuel	35.0	35.0	35.0	35.0	35.0	35.0	24.2	21.1	17.0	13.9	291.9	17.9	17.4	14.1	10.7	9.2	361.2	68.8
Others	33.4	33.4	33.4	26.1	17.6	15.4	5.2	3.7	3.0	2.5	123.9	5.1	3.0	2.4	1.9	1.7	196.0	37.2
Total	68.4	68.4	68.4	61.1	52.6	50.4	29.4	24.8	20.0	16.4	415.8	23.0	20.4	16.5	12.6	10.9	557.2	106.0
Non-Taxable Chemical Extract and Fuel Oil Equivalent Disposition, MMBBL																		
Refinery Fuel	35.0	35.0	35.0	35.0	35.0	35.0	29.4	21.1	17.0	13.9	291.9	17.9	17.4	14.1	10.7	9.2	361.2	68.8
Others	0.0	0.0	0.0	0.0	0.0	0.0	5.4	13.7	18.0	21.1	58.1	17.1	17.6	20.9	24.1	25.8	163.6	31.2
Total	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	350.0	35.0	35.0	35.0	35.0	35.0	525.0	100.0
Net Taxable Production	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	262,500	2,625,000	262,500	262,500	262,500	262,500	262,500	3,937,500	
Royalty																		
State Royalty	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	500,000	50,000	50,000	50,000	50,000	50,000	750,000	
Federal Royalty	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	1,000,000	-	-	-	-	-	1,500,000	
Severance	65,500	61,500	54,000	46,800	39,600	32,500	25,200	18,000	10,800	3,600	360,000	-	-	-	-	-	540,000	
Conservation	-	-	13,000	21,500	30,500	36,000	37,000	82,500	90,000	95,000	411,500	10,000	10,000	11,000	40,000	50,000	571,500	
Other	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	500,000	50,000	50,000	50,000	50,000	50,000	750,000	
Subtotal	265,500	261,500	267,000	268,300	270,100	268,500	262,200	300,500	300,800	298,600	2,771,500	110,000	110,000	111,000	140,000	150,000	4,111,500	
Net Taxable	(3,000)	1,000	(4,500)	(5,800)	(7,600)	(6,000)	300	(38,000)	(38,300)	(36,100)	(154,000)	152,500	152,500	151,500	122,500	112,500	(173,500)	
Federal Royalty Oil	0.15	0.15	0.16	0.16	0.02	0.10	0.15	(0.50)	(0.52)	(0.49)	(0.05)	4.66	4.64	4.61	3.29	3.14	1.43	

( ) Net Taxable Production is Taxable Royalty Oil, whichever is less.

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WHAT IS THE BOTTOM LINE?

AOC believes that the State should use its Prudhoe Bay royalty oil to sponsor a petrochemical refinery in Alaska. However, if and when the State so decides by taking its oil in kind, it assumes the same risks and enjoys the same potential for profit as does any owner of property. Thus, AOC believes the State must be involved in the decision making and does not believe the State should be bound by guidelines which have proved to be unrealistic. Its real protection lies not in guidelines, but in a thorough understanding of the industry it proposes to sponsor.

AOC's principals have a demonstrated track record and, to quote Bonner & Moore:

> "The development plan set forth by AOC is sound. It has the very important merit of bringing more chemical companies into Alaska. This also tends to alleviate the competitive problems mentioned earlier. If petrochemical plants were built by present market suppliers around a core crude-processing facility, then those plants would almost assuredly be planned to supply new increments of demand for each company's existing markets. This would be a healthy kind of development."

In developing its proposal to implement the above plan, AOC has tried to be candid. It has worked hard to develop a workable concept and a contract which fits the real world. In actuality, it costs the State nothing more than it will spend otherwise.

Last, but certainly not least, resident Alaskans are equal in management and development of the project.

APPENDICES

APPENDIX I AOC Forecast of Prudhoe Bay Production

APPENDIX II Recalculation of the Deemed Economic Price

APPENDIX I

AOC FORECAST OF PRUDHOE BAY PRODUCTION

During the negotiations, AOC repeatedly asked for the State's forecast of the oil volumes that would be available under the contract. AOC was referred to the Department of Natural Resources and obtained some suggestions based on the Van Poolen report. The only other guideline from the State was that the maximum would be 85% of the available royalty oil. Using this information, on December 3, 1977 AOC transmitted to Joe Moore and Commissioner LeResche its estimate of the oil that would be available. Such estimate included an assumed additional 300,000 B/D of oil from other sources by 1982, bringing the total to 1.5 million B/D. The information supplied by the Department indicated that the decline might be 9% or 10% per year and, therefore, these volumes were declined at 9% per year, starting in 1986.

On February 1, in response to a written inquiry, Commissioner LeResche identified Case 3A of the Van Poolen report as the appropriate forecast. In the interim, however, AOC had made its own independent evaluation of the likely production rates. These have been identified in the main body of this report. Confidential information available to AOC indicates that a 7% decline, starting in 1986, is indicated rather than the previously used 9%. This, in effect, allows for some tertiary recovery. Thus, AOC has modified its December 3, 1977 forecast to reflect this slower rate of decline. Table I-1 shows the development of this forecast. It will be noted that this forecast shows the highest rate of production of any forecast in the latter years. AOC believes it to be a reasonable forecast.

TABLE I-1

ALASKA OIL & CHEMICAL COMPANY

PRUDHOE BAY

AOC FORECAST OF PRODUCTION

Thousand Barrels per Day

	Prudhoe Bay	Other	Total	Available Royalty @ 12.5%	Plant Capacity or 85% of Available
1978	1,000	-	1,000	125.0	
1979	1,200	-	1,200	150.0	
1980	1,200	100	1,300	162.5	
1981	1,200	200	1,400	175.0	
1982	1,200	300	1,500	187.5	
1983	1,200	300	1,500	187.5	100.0
1984	1,200	300	1,500	187.5	100.0
1985	1,200	300	1,500	187.5	100.0
1986	1,116	300	1,416	177.0	100.0
1987	1,038	300	1,338	167.3	100.0
1988	965	300	1,265	158.1	100.0
1989	898	300	1,198	149.8	100.0
1990	835	279	1,114	139.3	100.0
1991	776	259	1,035	129.4	100.0
1992	722	241	963	120.4	100.0
1993	671	224	895	111.9	95.1
1994	624	209	833	104.1	88.5
1995	581	194	775	96.9	82.3
1996	540	181	721	90.1	76.6
1997	502	168	670	83.8	71.2

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February 1978

APPENDIX II

RECALCULATION OF THE DEEMED ECONOMIC PRICE

The "in-values" developed in the Bonner & Moore report are based on the stipulated 1.2 or 1.8 million B/D of North Slope production. AOC believes the Sohio pipeline project (or its equivalent) will be built and therefore AOC believes $6.33 is a reasonable "in-value" in 1985. (Case D in Bonner & Moore report.)

It should be noted that at 1.2 million B/D the maximum available royalty oil assuming only 85% is available is only 130,000 B/D and that at 1.8 million B/D is only 190,000 B/D. Thus, only at the assumed 1.8 million B/D rate could a 150,000 B/D refinery be satisfied during the peak years, and in no case can a 250,000 B/D refinery be satisfied with royalty oil alone.

The economic calculations are based on an assumption that the facilities will operate at <u>full rated capacity</u> for 16 years. AOC contends that with the forecast volumes available it is unrealistic to calculate economics based on assumed full capacity operation. AOC has, therefore, computed the actual amount of royalty oil that would be available to service all three refineries. Table II-1 shows the forecast utilizing as a basis AOC's forecast. As mentioned previously, this is the most optimistic forecast AOC has found. In all cases it has been assumed that the refineries would operate 350 days per year, but would have sufficient storage to take crude oil every day in the year. Again, this is the most optimistic approach. It will be noted that even for AOC's proposed 100,000 B/D refinery there is a shortfall, with the average oil available over 16 years being slightly under 90,000 B/D. The

TABLE II-1

ALASKA OIL & CHEMICAL COMPANY

FORECAST THROUGHPUT FOR VARIOUS REFINERIES

USING PRUDHOE BAY ROYALTY OIL

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Total	Avg. B/D
Available																		
Prudhoe Bay Royalty ACC Forecast																		
MB/D	187.5	187.5	187.5	177.0	167.3	158.1	149.8	139.3	129.4	120.4	111.9	104.1	96.9	90.1	83.8	77.9	2,168.5	135.5
365 Days MMB	68.4	68.4	68.4	64.6	61.1	57.7	54.7	50.8	47.2	43.9	40.8	38.0	35.4	32.9	30.6	28.4	791.3	135.5
Disposition																		
100,000 B/D Refinery:																		
350 Days MMB[1]	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	34.7	32.3	30.1	28.0	26.0	24.1	525.2	89.9
Other	33.4	33.4	33.4	29.6	26.1	22.7	19.7	15.8	12.2	8.9	6.1	5.7	5.3	4.9	4.6	4.3	266.1	45.6
	68.4	68.4	68.4	64.6	61.1	57.7	54.7	50.8	47.2	43.9	40.8	38.0	35.4	32.9	30.6	28.4	791.3	135.5
150,000 B/D Refinery:																		
350 Days MMB[1]	52.5	52.5	52.5	52.5	51.9	49.0	46.5	43.2	40.1	37.3	34.7	32.3	30.1	28.0	26.0	24.1	653.2	111.8
Other	15.9	15.9	15.9	12.1	9.2	8.7	8.2	7.6	7.1	6.6	6.1	5.7	5.3	4.9	4.6	4.3	138.1	23.7
	68.4	68.4	68.4	64.6	61.1	57.7	54.7	50.8	47.2	43.9	40.8	38.0	35.4	32.9	30.6	28.4	791.3	135.5
250,000 B/D Refinery:																		
350 Days MMB[1]	58.1	58.1	58.1	54.9	51.9	49.0	46.5	43.2	40.1	37.3	34.7	32.3	30.1	28.0	26.0	24.1	672.4	115.1
Other	10.3	10.3	10.3	9.7	9.2	8.7	8.2	7.6	7.1	6.6	6.1	5.7	5.3	4.9	4.6	4.3	118.9	20.4
	68.4	68.4	68.4	64.6	61.1	57.7	54.7	50.8	47.2	43.9	40.8	38.0	35.4	32.9	30.6	28.4	791.3	135.5

Note: (1) Refinery Capacity or 85% of available, whichever is smaller

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150,000 B/D refinery, because it takes more in the peak years, would average almost 112,000 B/D, and the 250,000 B/D refinery would average 115,000 B/D.

Since Bonner & Moore's economics were based on full capacity operation, AOC has recalculated Bonner & Moore's economics including the revised economics for ALPETCO shown in Joe Moore's letter of February 10. The results of these calculations are shown in Table II-2.

In making these calculations, AOC has accepted all Bonner & Moore's numbers, except that capital related items have been increased to reflect the lower quantity of royalty oil. It will be noted that in all cases premiums forecast move into substantial debits, ranging from $3.45 debit for ALPETCO to $0.82 debit for Alaska Petroleum Company. Put another way, these deemed values would be those that would flow if the optimistic AOC volumes alone were available for the proposed refinery. AOC believes this further demonstrates that the concept of very large in-State facilities needs close examination by the Royalty Board.

TABLE II-2

ALASKA OIL & CHEMICAL COMPANY

ADJUSTED DEEMED ECONOMIC PRICE

	ALPETCO		Petrofining		APC	
	At Rated Capacity 150 MB/D	Available Royalty Oil 111.8 MB/D	At Rated Capacity 250 MB/D	Available Royalty Oil 115.1 MB/D	At Rated Capacity 150 MB/D	Available Royalty Oil 111.8 MB/D
Operating Charge Calculation						
Direct Operating Expenses	5.00	5.00	0.97	0.97	1.06	1.06
Capital-Related Charges	12.32	16.54	1.83	3.98	2.19	2.94
Total Charges	17.32	21.54	2.80	4.95	3.25	4.00
Deemed Economic Price Calculation						
Average Product Price	28.65	28.65	13.88	13.88	13.74	13.74
Less Total Charges	(17.32)	(21.54)	(2.80)	(4.95)	(3.25)	(4.00)
Crude Oil Purchase Cost	11.33	7.11	11.08	8.93	10.49	9.74
Entitlement Credit	2.30(1)	2.30	2.30	2.30	2.30	2.30
Actual FOB Plant	13.63	9.41	13.38	11.23	12.79	12.04
Crude Tankering	(0.37)	(0.37)	(0.37)	(0.37)	(0.37)	(0.37)
Taps Tariff	(6.16)	(6.16)	(6.16)	(6.16)	(6.16)	(6.16)
Deemed Economic Price	7.10	2.88	6.85	4.70	6.26	5.51
Anticipated Premium (Debit)						
Deemed Economic Price	7.10	2.88	6.85	4.70	6.26	5.51
In-Value	6.33	6.33	6.33	6.33	6.33	6.33
Premium (Debit)	0.77	(3.45)	0.52	(1.63)	(0.07)	(0.82)

Note: (1) Pursuant to Joe Moore's letter of February 10, 1978

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Dillon, Read & Co. Inc.
46 William Street
New York 10005

State of Alaska

Alaska Royalty Gas Study

February 15, 1978

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Dillon, Read & Co. Inc.

Alaska Royalty Gas Study

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This study presents a range of options for the ownership and financing of a gas conditioning and transmission system (the "System") for the distribution of the State of Alaska's royalty gas and gas liquids. The central assumption in this study is that any gas conditioning and transmission system will be developed on an intra-state basis, and therefore will not be subject to Federal regulation under existing law. In the event an inter-state route is chosen for the System, or the State elects to participate in any interstate system, certain of the options discussed may require modification.

Means of Financing

There are three basic approaches to financing the System: investment and ownership by the State; investment and ownership by private interests; and, investment and ownership on a joint basis by the State and private interests. Funds for investment by the State will generally be derived from the issuance of tax-exempt obligations of the State or a State authority. Where the State makes no investment in the System, private funds will be utilized to finance the investment, and the System will be privately owned. For joint investment alternatives, each party will finance its individual ownership share on the aforementioned bases.

We have organized the discussion of ownership and financing alternatives in five sections, as follows:

Tab 1 - Ownership and Financing by the State

Tab 2 - Ownership and Financing by Private Interests

Tab 3 - Ownership and Financing by Joint State/Private Interests

Tab 4 - Ownership and Financing Through the Alaska Royalty Financing Trust

Tab 5 - Other Means of Ownership and Financing

The Alaska Royalty Financing Trust presented in Tab 4 is a means of financing ownership on behalf of the State and, along with the Alaska Royalty Gas Trust, described in Tab 6, provides a mechanism for passing the benefits of certain of the State's royalty holdings directly to State residents.

Evaluation Criteria

Each alternative for investment in and financing of the System can be evaluated against a fixed set of criteria, which we have developed as part of this report. In the development of these criteria, we have considered the State's goals and objectives with respect to the System as they have been indicated to us by State representatives. Briefly, such goals include:

- attracting new industry to the State which will improve the composition of the State's employment base by increasing the availability of jobs that demand higher skills and pay higher wages;
- increasing the inflow of revenues to the State while reducing required expenditures for social programs;
- developing a base of assets that will continue to be of benefit to the State beyond the point of depletion of

the royalty gas reserves;

- providing a mechanism for the distribution of revenues derived from the sale of the royalty gas to residents of Alaska; and,
- maximizing the State's financial return on its investment in the System and its holdings of royalty gas and gas liquids.

These goals and objectives provide the basis for the development of the following criteria, against which each alternative must be evaluated:

1. The ability to provide gas for sale to industrial users at a price which will attract new industry to the State. Factors affecting the price of delivered gas will include the interest rate on debt required for development of the System and/or the opportunity a given alternative provides for utilizing depreciation benefits, investment tax credits, and depletion allowances.
2. The degree to which the operation of the System will provide revenues to the State, including revenues generated by new industrial activity.
3. The efficiency of the mechanism provided by each alternative for distributing available revenues to residents of the State.
4. The extent to which each form of ownership and financing requires an actual cash investment by the State or utilizes State guarantees of either private credit or independent

State authority credit.

5. The extent to which new legislation and/or new administrative structures will be required to enable the completion and operation of the System under each form of financing and ownership.

Tab 7 of this report contains a matrix which weighs each of the ownership and financing alternatives contained in Tabs 1 - 4 against the above-outlined criteria.

Revenues Received From the System

Revenues from the disposition of the State's royalty gas holdings can be realized from three distinct sources which include:

- charges for the sale of the royalty gas at the wellhead, distinct from charges for the conditioning and transmission of such gas in the facilities of the System. As owner of the royalty gas, the State will derive all or part of the revenues attributable to this source;
- charges levied for the conditioning and transportation of the royalty gas, distinct from charges for the gas itself. Where the State is owner of the System by virtue of its investment in the facilities, this source of revenues will accrue to the State. However, to the extent the facilities are owned by private interests, such revenues will constitute the return on private investment;
- a general increase in revenue accruing to the State as a result of taxes levied on new industries locating in Alaska

due to the availability of the royalty gas. Where the System is owned by a taxable private entity, the System itself would comprise an additional source of revenues for the State.

Without knowledge of the System's capital requirements, charges for the gas and its conditioning and transmission, or the rate at which applicable taxes will be levied, it is impossible to quantify total revenues which will accrue to the State under each alternative.

Revenues received in connection with the operation of the System, including from taxes levied on new industry located in the State, and where applicable, from taxes levied on the System itself, will be available for distribution in the following manner:

- As required by amendments to the State Constitution adopted in November of 1976, at least 25% of the revenues received from prices charged for the royalty gas at the wellhead must be deposited into the Alaska Permanent Fund. We have been informed that any other revenues, including those received from charges for conditioning and transmission, need not be so deposited.
- Where the State has issued no financial obligations on behalf of the System, and has no investment in it, available revenues after deposit into the Permanent Fund can be allocated to the State's General Fund, with no further requirements. Where the State has issued general obliga-

tion bonds to finance the System, however, revenues received after deposits to the Permanent Fund may be paid into the General Fund and utilized to pay debt service on the general obligation bonds issued in support of the State investment. Finally, where the State has used revenue bonds for providing investment funds, available revenues must be paid, to the extent required, into the special funds created for the purpose of paying debt service on such revenue bonds. Remaining funds can thereafter be paid into the General Fund.

- Funds remaining in the General Fund and not required for debt service may be utilized as the State deems desirable, including for distribution to residents of Alaska in the form of tax reductions or direct cash payments.

The remainder of this study is devoted to a detailed analysis of the options available for development and financing of the System. Information contained in Appendices A and B relates to specific matters considered in conjunction with the discussion of ownership alternatives described in Tabs 1 - 5.

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Tab 1 - Ownership and Financing by the State

The financing and ownership alternatives described in this section are principally distinguished by the requirement that the State, or a State authority, make a direct cash investment in the System. As a consequence, because the State will be the owner of the facilities, revenues will be available to it from all three sources outlined previously: the wellhead price of the gas; charges for conditioning and transmission in the System; and any general increase in taxable economic activity in the State. Since the System will be owned by a tax-exempt institution, the facilities themselves will not be taxable.

The State, or a State authority, will be able to issue tax-exempt obligations as a means of securing funds for its investment in the System. Such obligations bear lower interest rates than the taxable debt of private issuers and, therefore, the cost of debt for any State-owned facility may be lower than for a privately-owned facility.

Briefly, there are two forms of tax-exempt obligations which may be utilized in conjunction with a State-owned System: general obligation bonds, which impart a full-faith-and-credit pledge of the State's ad valorem taxing capacity, and; revenue bonds, which would pledge only an identifiable stream of revenues from the System as security. By this definition, revenue bonding would appear to imply less of an overall State obligation than general obligation bonding. Clearly, a project of the magnitude and complexity of the System will present substantial investment risks. As a result, it will be likely that

the State will have to guarantee completion of the facilities or provide a long-term guarantee of the revenue bonds, at least until such time as the System is demonstrated to be economically viable, in order to make such obligations attractive to the bond markets. Therefore, both forms of tax-exempt debt will require use of the State's credit.

Because the intended primary users of the output of the System are to be privately-held industries, tax-exempt debt issued for the State's investment in the System must comply with stated regulations of the Internal Revenue Service with respect to tax-exempt obligations. We have included a copy of the appropriate Internal Revenue Service Regulations on this matter as Appendix A to this report.

Briefly, under Section 103(b) of the Internal Revenue Code, if more than 25% of the revenues pledged in support of a state or local government bond offering is to be derived from payments made by non-exempt, for-profit industrial users, the obligations will be considered industrial development bonds, and issues of such bonds in amounts greater than $1,000,000 will not be tax-exempt, unless certain other qualifications are met. The only such qualification relevant to the System is contained in Section 103(b)(4)(E), which allows for tax exemption on industrial development bonds offered in any amount for facilities which will provide gas to users located only in a contiguous two-county area, provided that the gas is made available for use by the general public in addition to specific industrial users. Whether or not the gas is actually purchased by the general public is irrele-

vant to this qualification, provided the gas is made available for such use.

The requirements stated in Section 103(b) will apply to issues of both general obligation and revenue bonds. Because a principal advantage of State ownership of the facilities arises from the use of lower interest rate, tax-exempt obligations, it is important to fully understand the conditions placed upon the issuance of such obligations in connection with the System, prior to examining specific structural alternatives for State ownership outlined below.

As owner of the System, the State will have sole responsibility for construction and operation of the facilities. It would be possible, however, to contract with a private organization to provide management services, thereby eliminating the need to develop an experienced staff of State personnel to manage the System. In addition, the State will be required to enact enabling legislation to empower it to invest funds in the System, whether such funds are derived from the issuance of general obligation or revenue bonds.

With the State as owner of the System, potential tax advantages such as depreciation and investment tax credits that have the effect of improving rate of return and lowering the after-tax cost of capital in a private ownership structure will not be available. Loss of such advantages is, of course, offset by the fact that the State will pay no taxes at all on revenues derived from the System and, further, can finance its investment with tax-exempt debt. The depletion allow-

ance provided for investments in natural resources such as gas and oil will be available, however, to those residents participating in the Alaska Royalty Gas Trust, described in Tab 6, and, thus, this Trust provides a measure of tax advantage to the State's residents that would otherwise be of no use to the State.

The following are the principal forms of State investment and ownership in the facilities of the System:

1A - Financing by General Obligation Bonding

The use of general obligation indebtedness to finance the State's investment in the facilities may provide the lowest interest rate debt available to the proposed System. Tax-exempt obligations of local governments bear lower interest rates than taxable obligations of private owners, and general obligation bonds secured by the State's full taxing powers are likely to bear interest rates lower than revenue bonds. Normally, general obligation bonds provide superior security for the investor, since the source of such security is the State's full ad valorem taxing capacity. Hence, the payment of principal and interest on any bonds of this kind offered on behalf of the System is not dependent upon the financial success of the System, but rather upon the State's overall financial condition.

It must be recognized, however, that among all the alternatives in this study, financing obtained through general obligation bonding represents the maximum drain upon the State's credit. Such bonds issued on behalf of the System will have an equal lien on the State's revenues and tax resources with all current and future outstanding

general obligation bonds, including those that may be issued for the construction of schools, government buildings, and other basic capital programs.

At year-end 1976, the State of Alaska had outstanding $540 million in general obligation debt, and was authorized to issue $840 million, although there is no constitutional limit on the total amount of such bonds which may be issued. The amount of capital required to construct a gas conditioning and transmission system would represent a considerable increase in outstanding general obligation indebtedness, probably in excess of the $300 million remaining from the current authorization. However, the increase in revenues available to the State and in the State's general tax base resulting from the System's development may at an early point negate the effects of the increase in outstanding general obligation indebtedness, and thereby not impair the State's ability to finance future projects.

Under this approach, the State, as in all general obligation bond offerings, would be required to obtain voter approval by referendum for the offering of securities in connection with the project. Unless its contracts for construction and management of the System, the State would also be required to designate and appropriately staff an agency or authority to operate the facilities.

To the extent the royalty gas is sold to industrial users at a price high enough to produce significant net revenues, such gas may become more costly and, hence, less attractive to such users.

However, because the cost of debt under this alternative is likely to be especially low, and revenues realized by the State are exempt from taxation, gas sold to industrial users at a price high enough to produce appreciable revenues for the State may, nevertheless, be attractively priced from the user's viewpoint, and therefore the System could more effectively attract taxable new industries to the State.

In considering the alternatives for investment and ownership presented in this study, it will always be necessary for the State to examine the trade-off between desired revenues from the sale of gas and the price of such gas to industrial users. The use of general obligation bonding, because it may have the lowest cost of debt and, therefore, the lowest fixed cost for debt service, provides more latitude to meet both the goals of obtaining revenues from the sale of gas and making such gas available at an attractive cost. In exchange for this flexibility, however, the State must be willing to fully offer its credit to the financing.

Revenues received in connection with the operation of the System may be deposited in the State's General Fund after making the required deposits in the Permanent Fund. Revenues derived from the increase in taxable industry in the State resulting from the System's operations will be deposited in the General Fund as well, as in the case of all tax receipts of the State. After meeting obligations on outstanding general obligation bonds, including bonds issued for other projects which have a lien equal to the System's bonds, excess revenues can be

used to either reduce the required level of taxation of State residents or to make direct cash payments to such residents.

1B - Financing by Revenue Bonding

In lieu of issuing full-faith-and-credit general obligation bonds to finance the State's investment in the System, the State, or a State authority, may instead issue revenue bonds for this purpose. Although there are numerous forms of such bonds, some of which will be described more fully herein, the basic distinguishing characteristic of revenue bonds is that the security offered for the payment of principal and interest is a pledge of only revenues derived from the operation of the System itself, rather than a pledge of all the State's revenues. As such, revenue bonding represents a source of financing that does not rely upon the State's own credit, and does not utilize the State's general obligation bonding capacity.

If structured in a form compatible with Section 103(b) of the Internal Revenue Code, the interest on revenue bonds is tax-exempt. As a result, such bonds would bear a lower interest rate than taxable obligations of a private issuer. Under most circumstances, the interest on such bonds is, however, higher than on general obligation bonds.

Since the only security offered on such bonds would derive from the operating cash flow of the System, the bond rating and, hence the interest rate, on such bonds would be highly dependent upon the anticipated operating results of the System. Theoretically, if the System's projected operating results indicated cash flow sufficient to cover debt service on the revenue bonds by a significant margin, the bonds

could receive a rating higher than the A1 rating applied to the State's general obligation bonds, and would carry a lower interest cost than such bonds.

In practice, however, undertaking the System, as we understand it, would be a complex venture involving a considerable amount of financing. For revenue bonds to be marketable, therefore, it would likely be necessary that the State both guarantee completion of construction of the System and guarantee the bonds themselves at least until such time as the System has clearly demonstrated an ability to pay debt service from its own operating revenues. A State guarantee of the bonds could take a number of forms, including a straightforward guarantee of principal and interest over the life of the issue, a guarantee of reserve funds created for the purpose of paying debt service on a year-by-year basis, or the provision of guaranteed throughput contracts which would be structured to assure a supply of gas for the System and, in the event the System is inoperable or purchasers cannot be found for the gas and gas liquids, would provide funds for the payment of debt service.

Clearly, the use of any of these guarantees creates a liability of the State that is contingent upon the successful operation of the System and, therefore, with the State acting as the back-up credit for the revenue bonds, such bonds may receive a rating and bear interest approximately equivalent to the State's full-faith-and-credit debt. If the System can be operated successfully, the State would not be obligated to act upon its guarantee. However, if the System is

unsuccessful, the State could be responsible for the full amount of principal and interest on the revenue bonds.

The State has already had experience with the issuance of revenue bonds through an independent authority, having created the Alaska Housing Finance Corporation for such purposes in 1971. We have included, as Appendix B to this study, a copy of the enabling legislation for the Corporation as an example of the structure of and required legislation for the creation of an independent authority. Under many circumstances, creation of an independent authority will remove the State's credit entirely from any revenue bond financing. Such is the case with respect to the Housing Finance Corporation. However, for a project such as the System, which embodies substantially greater risk than the programs of the Corporation, it will be necessary to apply State guarantees to authority-issued bonds.

It has already been indicated in the introduction to this study that tax-exempt bonds issued for the purpose of constructing a gas conditioning and transmission system to serve primarily industrial customers who would be purchasing more than 25% of the System's output would probably be classified as industrial development bonds. As such, the distribution of the gas would have to be accomplished on a basis compatible with Section 103(b)(4)(E) of the Internal Revenue Code, as currently structured: that is, the gas would have to be made available to the general public and distributed only in a contiguous, two-county area. In practical terms, making the gas generally available would require allowing individual State residents to

gain access to the System's output. The requirement for distribution to a contiguous two-county area applies only to the points of delivery of the System, and not to its overall location. Hence, if the pipeline transversed three counties, but delivered gas in only two contiguous counties, the financing would comply with IRS Regulations. Assuming the intended industrial users of the System were to locate within a two-county area, the System could accomplish its goal of attracting new industrial activity to the State.

The structure of a revenue bond offering for the System would require the creation of certain special funds for the disposition of the System's cash flow. Certain of these funds would be utilized for the payment of principal and interest on the bonds, when due. Others would constitute reserve funds to create a pool of available cash for the payment of operating and maintenance expenses and the payment of debt service for a specified period of time in the event the System temporarily cannot generate funds with which to pay principal and interest on the bonds. After meeting all requirements for deposits into these special funds, remaining funds can be deposited into the State's General Fund. Where the revenue bonds have been issued by an authority, such authority could pay remaining funds into the State's General Fund after payment of debt service and deposits into other special funds. As in the case of general obligation financing, funds deposited into the General Fund can be utilized at the State's discretion, including for distribution to residents of the State in the form of tax reductions or direct cash payments.

The lower interest rate associated with tax-exempt financing under this approach, as in the case of general obligation bonding, will provide the State with latitude to meet both the objectives of realizing revenues from the operation of the System and providing gas at an acceptable price to industrial users. The degree of this latitude will vary with the level of guarantee provided by the State for the financing and the projected operating results of the System.

Finally, under this approach, the State, or the authority, will be required to construct and manage the System or contract for its construction and management. In addition, enabling legislation must be enacted specifying the State's or the authority's powers and responsibilities with respect to the System. The example enabling legislation contained in Appendix B will serve as a sample format of the required statutes.

1C - Initial Financing Through General Obligation Bonding - Subsequent Financing by Revenue Bonding

A review of the two alternative financing and ownership options previously discussed in this section indicates that, between the two alternatives, financing through general obligation bonding provides the benefit of a lower interest rate on debt, but has the long-term disadvantage of requiring the full use of the State's credit for the financing. Conversely, the use of revenue bonds may modify the requirement for the use of the State's full-faith-and-credit backing, but is likely to result in higher interest rate financing and may, nevertheless, require State guarantees. The key variable affecting

both the interest rate on the revenue bonds and requirements for State guarantee is the performance of the System in providing adequate revenues for the payment of debt service.

By providing for the construction financing of the System through the issuance of general obligation bonds, and thereafter financing the long-term operation of the System with revenue bonds, it may be possible to combine the most beneficial aspects of each approach and maintain a relatively low cost of debt. Separately financing the construction and operating phases of a project of this scope is not uncommon, and a modification of this approach is applicable to the System.

Under this alternative, the State would fund its investment in the facilities through the issuance of short-term general obligation debt. Such debt would bear lower interest than general obligation bonds issued to finance the System over its entire operating life because of its shorter term to maturity. Ideally, the term of the initial general obligation bond financing would cover the construction period of the System as well as a reasonable interim operating period.

Thereafter, the System would be refinanced through the issuance of revenue bonds, with proceeds of the bond offering used to retire the short-term general obligation bonds. By staging the financing in this manner, the revenue bonds would not be offered until the facilities have been completed, and the System has had an interim operating period during which its ability to generate adequate

revenue for debt service payment could be demonstrated. Depending upon the performance of the System during this period, it may be possible to offer the revenue bonds free of any State guarantee. The interest on revenue bonds may be as low or lower than on general obligation bonds of equivalent maturity if the System's performance warrants a bond rating greater than A1. However, as in all cases where short-term obligations are offered to finance construction, the State must bear the risk that the project will prove unsuccessful, and cannot be refinanced through revenue bonds. If such is the case, the State will be responsible for the payment of principal and interest on its initial short-term debt.

As a further modification of this approach, the State may choose to finance and own the System for a short-term initial period, and thereafter transfer the facilities to an independent authority which has issued revenue bonds for the purpose of purchasing the System from the State. The State would, in turn, use the proceeds to retire its short-term indebtedness, and would be relieved of the responsibilities of ownership.

This latter method of financing is patterned after the experience of the Federal Government with the Tennessee Valley Authority ("TVA"), a system of electric generating facilities initially financed by the Government in the 1930's. TVA, which has developed into a highly successful independent venture, now issues its own revenue bonds for the continued expansion of its facilities, and TVA provides for repayment of the initial Federal investment from its net revenues.

The remaining characteristics of tax-exempt financing which have been previously described pertain to this alternative as well. Responsibility for construction and management of the System will rest with the State, unless the State contracts for such responsibilities with a private organization. Further, the lower cost of tax-exempt financing will provide greater latitude in setting a price for the royalty gas that will provide net revenues to the State, but still be low enough to attract industries who would use the gas in their manufacturing operations.

Tab 2 - Ownership and Financing by Private Interests

The financing and ownership alternatives described in this section are principally distinguished by the requirement that private interests - private corporations or individual shareholders - make the only direct investment in the System. As a consequence, because such investors will be the owners of the System, and not the State of Alaska or a State authority, the State will derive revenues only from charges for the royalty gas and gas liquids supplied to the facilities, and as a result of any increase in taxable economic activity in the State. As a privately-owned facility, the System will itself be taxable. Revenues realized from charges for conditioning and transmission of the royalty gas will flow to the owners of the facilities, as a return on their investment in the System.

From the State's standpoint, this approach is attractive because (1) it provides present value benefits by allowing the State to achieve substantial revenues (from royalties and tax collections) without any investment; (2) it frees the State from the burdens of ongoing administration and management of the System; and (3) it preserves the State's financial and managerial resources for use in other areas. Once a more detailed evaluation of the economic and technical viability of the System has been made, it is these advantages which must be weighed against the possibly greater dollar income from State ownership.

Private investors will consist of two groups: pipeline operators who would operate the System for a profit; and the industrial users

of the gas themselves who would be willing to build and operate the System as a means of insuring the supply of the State's gas for their own manufacturing operations. Before a pipeline operator would undertake the venture, there must be a demonstrated market for the gas as reflected by actual contracts for the purchase of the gas by industrial users, or the existence of a substantial number of the users in the proposed service area. Given the potentially significant amount of capital required to construct the proposed facilities, it is highly unlikely that such investors would undertake the financing without reasonable assurance of a rate of return for their investment comparable to the rate of return on similar facilities currently in operation.

For potential investors who would use the gas themselves, the State must agree to provide the gas at a price which is sufficiently attractive to warrant investment both in the System's facilities and in industrial plants which will utilize the delivered and conditioned product.

Any debt offered for financing the System by private interests will be taxable, with the exception of the industrial revenue bond alternative described under 2-C, below. As a result, such debt will bear higher interest than general obligation or revenue bonds offered by the State. The resulting higher cost of such debt will inherently require higher charges for conditioning and transmission services, and the State must again consider the trade-off between revenues from its sale of gas to the facilities and the goal of providing

gas to potential new industries at the most attractive price after conditioning and transmission. This problem is exacerbated by the higher cost of debt service on taxable obligations of a private issuer.

As a private operation, the System would provide certain tax advantages that can be utilized by private investors to improve the after-tax rate of return on an investment in the facilities. Among these advantages are depreciation on the System's physical plant, and investment tax credits. The availability of such benefits may offset, to a degree, the burden of higher cost debt.

There is no need under these approaches to comply with IRS Regulations regarding availability of gas for general use or distribution in a two-county area except in the case of industrial development bonding or the use of State funds during an initial operating period. Further, the State will have no responsibility for the operation of the System and, with the exception of the use of industrial revenue bonds or initial State financing, will have no need to enact enabling legislation in connection with financing the project. This form of financing will not utilize the State's credit or require State investment.

The following are the alternatives for private investment in the System:

2A - Financing and Ownership by Private Corporation or Private Joint Venture

This approach represents the most traditional method of financing

a project such as the System, with funds provided by a single corporation or group of corporations acting as a joint venture. The potential investors on this basis might include those who would own and operate the System as revenue producing facilities, or those who intend on utilizing the royalty gas for in-state manufacturing operations, and would finance the System as a means of obtaining access to the gas.

Whether the investors in the System are pipeline operators or the intended users of the end product, the requirement for taxable debt financing will inherently increase the cost of providing service through the System. This will create, in turn, more pressure on the State than where tax-exempt obligations are used to provide the royalty gas to the facilities at a relatively low price in order to maintain any cost advantage to locating industry in Alaska. As indicated in the introduction to this section, the availability of depreciation and investment tax credits will partially offset, on an after-tax basis, the increased cost of servicing taxable debt.

Because the State will make no investment in the System, it will not be entitled to receive revenues directly from charges for conditioning and transmission. Private investors will receive such benefits, whether in the form of revenues for a pipeline operator, or access to the lower cost of royalty gas for investors who are the intended users of the gas. The State will, of course, obtain revenues from the sale of the gas, taxation of increased economic activity, and taxation of the System itself.

Revenues received by the State from these sources will be

available for disposition in whatever form considered appropriate, including distribution to State residents. Deposits must be made, as required by constitutional amendment, into the Alaska Permanent Fund prior to any other distribution.

This approach has no requirements for utilization of the State's credit, either in the form of direct debt obligations or the guarantee of another party's borrowings. However, for the same reason that it will be necessary to provide purchase contracts for the gas prior to construction, it will similarly be necessary for the State to contract on a long-term basis for the sale of the royalty gas at specified prices. In this manner, many of the higher risk elements of the venture will be diminished, since supply and demand for the gas will be reasonably assured.

2B - Financing and Ownership by Private Corporation or Private Joint Venture - Guarantee of Debt by Industrial Users or State of Alaska

This approach embodies a limited modification of the method described in 2-A, above, and applies solely to the case where the private investors in the System are pipeline operators. The modification consists of the provision of a guarantee of any debt issued by a private corporation to finance the System by either of two sources: the State of Alaska, or; the intended users of the conditioned and transported gas.

The provision of a guarantee by either source can be viewed as a form of investment in the facilities. In this sense, the

guarantor would be entitled to a return on this investment. Under the assumption that the availability of the guarantee would improve the market acceptance of the debt, the interest rate on the debt, and hence the level of debt service, would be diminished, and the royalty gas would be available at a lower cost. For the State, the return on this investment would be realized in the resulting ability to either charge more for the gas at the wellhead, or realize a greater increase in taxable industrial activity due to the availability of a less expensive end product. For the industrial users, the return on this investment would be access to a long-term supply of gas at a lower price.

It should be apparent that the use of a guarantee will be of benefit only if the guarantor has a credit rating higher than the rating on any debt issued by the pipeline operator intending to invest in the System. The provision of a guarantee by the State will not alter the taxable nature of the debt. It is unlikely that the private industrial users would guarantee the debt of the facilities unless both the State and the pipeline operator contractually agreed to provide the gas and transmission and conditioning services at a favorable price.

The remaining characteristics of private forms of ownership, previously enumerated, would not be modified by this method of financing.

2C - Industrial Development Bonding

Earlier in this report, under the discussion of forms of

ownership and financing by the State of Alaska, reference was made to tax-exempt financing of the System under Section 103(b)(4)(E) of the Internal Revenue Code. In that context, revenues pledged to the payment of debt service were to be derived from the sale of gas to industrial users, and ownership of the System would rest with the State or a State authority. However, it is also possible to offer such bonds whereby the System would be leased or sold to private interests, with lease or installment sales payments pledged to the payment of debt service on the bonds. This form of transaction, because it ultimately involves passing of the ownership interest in the facilities to private parties, is considered in this report to be a form of private ownership.

In this option, an industrial development body created by the State would offer tax-exempt revenue bonds for the construction of the System. A pipeline operator or the intended users of the royalty gas would execute a lease agreement with a fixed dollar purchase price for the System upon expiration of the lease, or an installment sales contract for the acquisition of the entire System over a proscribed time period after completion. The terms of such agreement or contract would be structured such that payments by the user would be sufficient to meet the issuing entity's financial obligations under the revenue bonds.

The lease agreement or installment sales contract should provide, in essence, for a guarantee of the revenue bonds by the lessee(s) or purchaser(s). In fact, the interest rate on the bonds would be

principally affected by the credit rating of such parties, and as a result, where this credit rating is AA or better, the industrial development bonds may bear a lower interest rate than the State's own Al-rated general obligation bonds. Structuring of the transaction in this form will make no utilization of the State's credit.

The advantages of this form of financing to both the State and the lessee(s) or purchaser(s) are apparent. The obligations will bear low, tax-exempt interest rates, and the State will be relieved of the burden of owning and operating the facilities. The private party to the transaction would maintain contractual responsibility for the construction of the facilities and for their operation and maintenance. If properly structured, it would be possible to preserve both the tax-exempt nature of the financing and the benefits of depreciation and investment tax credits which, in combination, may provide the lowest cost of financing of any of the alternatives discussed in this report.

Compliance with IRS Regulations concerning the delivery of the gas within a contiguous two-county area, and the availability of the gas to the general public, would be required to preserve the tax-exempt nature of the obligations. This would pertain both to instances where the private party consisted of a pipeline operator or the actual end users of the gas.

Under this form of financing the State would not be entitled to the receipt of revenues from charges for conditioning or transmission of the gas having made no investment in the facilities, but

would be limited to revenues obtained from the sale of the gas and the increase in the tax base of the State. The System itself would be a taxable entity for Federal income tax purposes. The State may also choose to tax the facilities, unless it acts to grant an exemption or tax relief.

This form of financing has been successfully accomplished a number of times in the recent past. For example, the Reynolds Metals Company financed pollution control equipment in 1976 using industrial development bonds issued through the Nueces River Authority, Texas, on the installment sales contract basis. The People's Gas Light and Coke Company similarly financed a substitute natural gas project in 1974 and 1975 through the issuance of industrial development bonds through the City of Joliet, Illinois. In this transaction, the Company leases and operates the constructed facilities, and will provide gas in accordance with IRS Regulations to a contiguous two-county area.

2D - Initial Financing and Ownership of System by State - Subsequent Ownership by Private Interests

A project of the scope and magnitude of the System clearly presents substantial investment risks. One way of eliminating or minimizing such risks is by entering into guaranteed (take-or-pay) contracts for the sale and purchase of the royalty gas prior to the investment of any funds. Another approach, discussed under this alternative, involves State funding of construction and initial operation of the System, and the subsequent sale of the facilities to private owners - either

pipeline operators or the users of the end product. In this manner, an investment of private capital in the System would be made only at the point where the facilities have been completed and have been operating for a period of time during which the availability of a proven market for the royalty gas has been demonstrated.

This approach to the financing is similar to the approach proposed under alternative 1-C, which recommended initial financing of the System through general obligation bonding by the State and subsequent refinancing with revenue bonds. In many respects, the principles underlying alternative 1-C and the option described here are similar. The interests of the private investor who relies solely upon the System's operating capabilities for a return on investment are similar to those of the investor in revenue bonds who can legally look only to the System's cash flow for repayment of principal and interest on bonds offered for the financing.

This approach is not without precedent. The Federal National Mortgage Association ("FNMA"), a privately-held and privately-financed corporation acting as a market-maker in secondary mortgage market operations, was originally developed as a Federally-financed agency of the U.S. Government. Initially, FNMA was designed to operate in a then relatively undeveloped market - the purchase and sale of outstanding conventional and FHA/VA-insured home mortgages, and ownership and financing by the Federal Government was the only form of financing suitable to such a venture.

In 1968, Congress enacted legislation enabling the sale of FNMA

stock to the public. Through a series of transactions completed in 1970, FNMA stock owned by the U.S. Government was retired through the payment to the Government of $216 million to cover its stock in the corporation and a portion of the corporation's earned surplus. Since that time, FNMA has issued its own taxable, non-guaranteed debentures, and FNMA stock currently trades on the New York Stock Exchange. Presently, the Federal Government's role in the corporation includes regulatory powers vested in the U.S. Department of Housing and Urban Development. The President of the United States appoints five of the corporation's fifteen board members, and the U.S. Treasury is authorized to lend up to $2.25 billion to the corporation.

Under this alternative, the State of Alaska would issue its own bonds to construct the facilities of the System, and finance an initial operating period. The term of such obligations would be shorter than the term of obligations issued to permanently finance the System, and the bonds would be tax-exempt. As a result of these two factors - short-term and tax-exempt status - it could reasonably be anticipated that such financing would be at exceptionally low interest rates.

Assuming the System, after completion and initial operations, demonstrates success in attracting customers for the royalty gas, the State would then negotiate with private interests for sale of the facilities. Such private interests, as previously indicated, could include pipeline operators or the users of the royalty gas.

Proceeds of sale of the System would be used to retire the State's short-term bonds, and the System would thereafter be privately owned and privately financed.

Prior to sale of the facilities to private interests, the State would be entitled to revenues derived from charges for conditioning and transmission services, as well as from the sale of royalty gas at the wellhead and from any taxes levied on new industry locating in the State. After the sale, charges for conditioning and transmission would accrue to the private owners as a return on their investment. It should be noted, in the event the System does not demonstrate success during its initial operations, or is not completed, and cannot be sold, the State will be liable for payment of principal and interest on the bonds issued for the financing.

Once privately owned, debt issued in connection with the System would be taxable, and therefore expenses for debt service would be higher than under forms of State ownership. This will limit the State's flexibility in meeting both the goals of selling royalty gas at a price high enough to maximize revenues, but low enough to maintain the cost advantages to industry to locating in Alaska. During the period of private ownership of the facilities, there would be no need to comply with IRS Regulations respecting general availability or distribution within a two-county area. However, during the State ownership period, distribution of the gas must be made on a basis compatible with such Regulations.

During both the phases of State and private ownership, the

elements of each respective form concerning management responsibility and receipt of revenues would apply.

Tab 3 - Ownership and Financing by Joint State/Private Interests

Throughout this report, we have assumed that, from the State's viewpoint, there are basic advantages and disadvantages to ownership of the System by either the State or private interests with respect to requirements for investment, management responsibilities, cost of financing and efficiency of management. From the perspective of either party, the means of financing the investment discussed herein are identical to the forms suggested in Tabs 1 and 2: the State's share of investment can be financed through the use of tax-exempt debt, and private investment will utilize taxable obligations. The principal characteristic of these proposals is that they will lead to long-term ownership in common by both the State and private investors.

The use of joint ownership allows for maintaining a significant involvement of private capital in the System. Private owners may include either pipeline operators or those industries intending to utilize the royalty gas in their manufacturing operations. This private involvement can be maintained while mixing tax-exempt capital with taxable capital contributed by the private owners, thereby providing an overall level of debt service that can generally be expected to be higher than for forms of complete State ownership, but lower than where private investors wholly own the System. This will allow the State a

moderate amount of latitude in pricing gas at the wellhead to meet both the goals of maximizing revenues from the sale of the gas and making the end product available at an acceptable cost to local industrial users.

As part owner of the System, the State will be entitled to revenues from charges for conditioning and transmission services in proportion to its overall investment in the facilities. In addition, the State will be entitled to revenues from the sale of the royalty gas and from taxes levied on new businesses locating in the State. Taxes may be levied, as well, on the earnings of private investors, unless the State chooses to specifically exempt such earnings from taxation. Private investors in the System will be entitled to the use of depreciation and investment tax credits. If the financing transaction is properly structured, it may be possible to pass such benefits on to private investors in an amount in excess of their proportional ownership of the System up to the full amount of benefits generated by the entire cost of the project. As a tax-exempt entity, the State can make no use of such benefits, and allowing private investors the full thereof may improve the rate of return on their investment.

IRS Regulations respecting general availability of the output of the System and the requirement to furnish gas to only a contiguous two-county area will pertain to the portion of

the System's output equal to the proportion of the State's investment financed by tax-exempt bonds. Thus, if the State of Alaska is a 50% owner of the facilities and its investment has been financed through tax-exempt bonds, only 50% of the output of the System must be distributed in a manner that will comply with the Internal Revenue Code.

Although the State will be a part owner of the facilities under the alternatives discussed herein, it will be possible to have the private owners maintain responsibility for management and operation if the State enters into operating agreements with the private owners that will assign to them such responsibilities. As will be demonstrated below, such operating agreements have been employed in past joint public/private financings.

Where the investment by both the State and private owners occurs prior to construction, an assurance of an acceptable rate of return will be required to attract private capital. The presence of the State as partner in ownership of the facilities will not, per se, diminish the risks. Guaranteed purchase and supply contracts will still be required.

Requirements for public referendum, enabling legislation and legislative authorization will apply to the State's investment in the System in the same manner that such requirements will apply to complete State ownership alternatives previously discussed.

The following are the alternatives for joint State/ private ownership and financing of the System:

3A - Combined Ownership and Financing by the State and Private Interests

Under this alternative, the State and a private investor(s) would finance the System, with each owning an undivided interest in the facilities. Each investor would be required to obtain capital for the investment in an amount equal to their proprotional ownership, and each would be entitled to a similarly proportional share of the System's earnings.

The State of Alaska would obtain funds for its investment from the issuance of general obligation bonds or revenue bonds. An independent State authority could be utilized for issuance of revenue bonds, and would act as owner of the System if this modification was utilized. The interest rate on general obligation or revenue bonds would be affected by the same factors affecting such obligations where the intended owner of the facilities was the State alone.

Requirements for guarantees of revenue bonds issued to finance the State's investment would pertain to this approach, including the full guarantee of such obligations, the guarantee of debt service reserve funds or the provision of throughput contracts assuring a supply of gas or the payment of debt service. Furthermore, the State could elect to finance construction

through short-term general obligation bonds and then refinance such debt with revenue bonds after completion of the System.

In the event private investors in the facilities do not have a credit rating strong enough to support the issuance of taxable bonds for their proportional share of the System, the State could choose to guarantee such bonds in the manner in which it would guarantee its own revenue bonds. Use of this guarantee, however, would represent a significant increase in use of the State's credit, and the State might be further responsible for the principal amount of such debt if the private investors are unable to meet debt service requirements pertaining to their ownership share of the facilities.

The overall cost of debt for the facilities if financed under this method would lie between the cost of debt for a System financed wholly by the State, and any alternative for completely private financing. Factors such as the form of obligation used by both the State and private investors for the financing, the level of guarantee, if any, provided to the bonds, the amount of equity capital contributed by private investors, and the credit rating of the private investors will affect the combined interest rate for the project.

The State's share of revenues from conditioning and transmission services, along with revenues from the sale of royalty

gas at the wellhead and from any increase in the tax base, would be applied to the appropriate funds, including the Permanent Fund, the State's General Fund, and special funds pertaining to revenue bonds, if used. The remainder could be distributed to Alaska residents, or otherwise utilized at the State's discretion.

There are several precedents for joint financing of major capital facilities by local governments and private industry. As an example, the Washington Public Power Supply System ("WPPSS") has participated in the financing and ownership of nuclear generating facilities with Pacific Power and Light Company, an investor owned utility. In the case of the Systems' Nuclear Unit #5, Pacific Power and Light owns a 10% interest in the plant and WPPSS owns 90%, with Pacific Power and Light having transferred operating responsibility for the plant to WPPSS as its agent under an operating agreement. Similarly, the Municipal Electric Authority of Georgia ("MEAG") has entered into joint ownership of electric generating plants with the Georgia Power Company ("GPC"), an investor owned utility, on a 50/50 ownership basis. In this case, MEAG has transferred operating responsibilities to GPC through similar operating agreements.

In both instances, the financing of each ownership share was accomplished independently by each investor, and the public investment was facilitated through the issuance of tax-exempt revenue bonds.

3B - Joint Financing by the State and Alaska Residents

The options for ownership and financing of the System presented in this report for the investment of private capital - including complete private or joint ownership - have not been specifically directed at ownership by the citizens of the State of Alaska. Alaska residents may participate as owners where they are shareholders in the existing corporations which invest in the facilities; however, none of the alternatives outlined thus far envisions the creation of a corporation owned, to a significant degree, by the residents for the purpose of making such investment.

The Government of the Canadian Province of Alberta is currently a 50% owner of the Alberta Energy Corporation ("AEC"), a holding company with a variety of investments in natural resources in the Alberta Province. AEC was initially capitalized with an investment by the Province of $75 million, and was wholly owned by the Province. In 1975, shares amounting to an additional $75 million were publicly offered, with such offering limited to purchase by provincial residents during a three week priority period. The offering was completely sold during the priority period, and AEC became, as a result, 50% owned by the Province and 50% by Albertans.

Using the Canadian experience with the Alberta Energy Corporation as an example, this alternative suggests the

development of a similar ownership structure for the Royalty Gas System. The State of Alaska would initially finance the construction and initial operating period of the facilities, and would subsequently offer shares in the System to Alaska residents. If funds were required for expansion of the System's facilities, the amount of shares offered would be equal to funds required for such expansion. If no expansion were contemplated, proceeds of the offering would be utilized to redeem a portion of the State's initial investment. In either case, the resulting facilities would be partly owned by local residents.

This approach provides a mechanism which would allow Alaska residents to participate in the benefits of profitable operation of the System through dividend payments and capital appreciation of their shareholdings.

To the extent of their investment in the facilities, the residents would be entitled to revenues derived from charges for conditioning and transmission. The State would similarly be entitled to a proportional share of such revenues, and could elect to distribute its share directly to the resident shareholders by allowing dividend payments on stock in the System to be paid to the residents in excess of their proportional share of ownership. As an alternative, the State could retain its dividends, and pass them through the General Fund for

distribution to residents who are not shareholders, or such funds may be disposed of in any desired fashion. Under this form of financing, the State would continue to be entitled to revenues from the wellhead price of the royalty gas supplied through the System and from any general increase in the tax base of the State.

Debt issued directly by the System would be taxable. Funds used for the State's initial equity investment, however, could be obtained through issuance of tax-exempt general obligation or revenue bonds. The interest rate on such bonds would vary, as affected by the same factors pertaining to tax-exempt obligations discussed throughout this report.

In the event the System is not completed or cannot be successfully operated, the State will be unable to market shares in the facilities to residents. In this event, the State, as sole owner of the System, will be fully responsible for its financing, management and operation.

Funds for the purchase of shares by State residents would be obtained by each investor. In the event the general economic level of the residents is such that it would be impossible to have a broad distribution of ownership if the residents must rely on their own income to secure funds, it would be possible for the State to guarantee bank loans for such purposes, much in the same manner that it would guarantee the borrowings of

a private corporate investor under any of the previous alternatives for full or partial private ownership. The State could further attract resident investment by offering a range of tax benefits for purchasers of shares in the facilities including State income tax deductions related to the number of shares purchased or an exemption from State taxation of dividend payments.

Tab 4 - Alaska Royalty Financing Trust

The Alaska Royalty Financing Trust (the "Financing Trust") is a potential alternative for the State to (i) finance all of its ownership of the System in lieu of the State financing options set forth in Tab 1; (ii) finance a part of its ownership of the System with the remaining part being financed with any of the State options set forth in Tab 1; and (iii) finance its share of ownership or cost of the System which would result from the joint State/private interest options set forth in Tab 3.

The Financing Trust would be a legal entity known as a "grantor trust" which would be entirely separate from the State. The State would sell to the Financing Trust specified percentages of its royalty interests on proven and producing oil and/or gas properties. The Financing Trust would pay cash to the State as consideration for the oil and/or gas royalties acquired, and the State would utilize the cash received, after providing for any required deposits to the "Permanent Fund", to finance all or part of the System facilities as set forth above. The Financing Trust would finance its cash requirements by the sale of trust certificates which represent beneficial ownership interests in the Financing Trusts assets. The Financing Trust would receive cash income from its share of royalty oil and/or gas and

would not, therefore, elect to take its share of reserves in kind.

The trustee(s) of the Financing Trust would be independent from the State and would be experienced in performing the administrative functions of a trustee. Commercial banks typically provide trustee services and are equipped to perform the necessary administrative functions. Most banks have established fees for providing trustee services which would include the collection of royalty income proceeds, investment thereof pending distribution, and distribution of revenues to trust certificate owners. As the assets of the Financing Trust will be oil and gas royalties, it would be important for the commercial bank trustee to be sophisticated in oil and gas matters.

While most legal entities provide the ability to amalgamate royalty interests from a number of unrelated properties and at the same time provide the opportunity to attract financing from a broad base of capital sources, a trust would appear to have certain advantages over other entities such as corporations or partnerships. A trust of the type envisioned is a pass-through entity for tax purposes and, as such, it is not deemed to be a taxable entity. The income received by the Financing Trust would be taxable to the trust certificate owners. The Financing Trust, therefore, provides

the potential ability to distribute income without the incidence of double taxation which would exist in a corporate entity organized for the same purpose. Theoretically, double taxation could also be avoided by use of a "non-profit" corporation, but this prospect would not appear to be possible given that the purpose of the corporation would be to finance the acquisition of producing royalty interests and the owners of the corporation's stock would not be likely to qualify as not-for-profit entities.

Although a partnership would also be a pass-through entity for tax purposes, a trust is nevertheless more desireable on a number of grounds. A trust provides greater liquidity, particularly if the trust certificates are registered with the Securities and Exchange Commission. If registered, the trust certificates could be freely traded in a manner similar to the trading market which exists for common stocks. The transfer of partnership interests is strictly limited, especially in the case of limited partnerships, by complex tax procedures which limit the free transferability of the partnership interests.

The portion of the State royalty interests to be sold to the Financing Trust and the properties from which they should be derived, would depend upon the amounts required to finance the System, and the State's revenue requirements

for other purposes, including deposits into the "General Fund" and the desired level of distributions to State residents.

The Financing Trust can provide certain tax benefits, in addition to the elimination of double taxation described above, which would not otherwise be available to the State. Any profit to the State from the sale of the royalty interests to the Financing Trust would not result in a tax to the State because the State is not a taxable entity. The Financing Trust would also provide the potential for utilizing cost depletion. A depletion allowance, cost or percentage, is similarly not available to the State as a tax-exempt entity. Cost depletion is available, however, to the trust certificate owners as a result of their cost basis in the beneficial ownership of the royalty interests acquired. The potential availability of cost depletion has the benefit of reducing the taxation of income received by the Trust owners by the total amount of the cost depletion. This benefit may provide the ability to reduce the amount of royalty interest necessary to provide a given after-tax return to the trust certificate owners.

Naturally, the trust certificate owners would have to be tax-paying individuals or institutions in order that the

cost depletion allowance could be utilized. The cost depletion allowance would not be useful to any potential nontaxable trust certificate owners such as pension funds. It could, however, be entirely possible to attract pension funds to purchase Financing Trust certificates; pension funds have historically demonstrated their willingness to purchase taxable debt securities at the same pretax rate of return provided to tax-paying securities purchasers.

In order to provide for financing through the Financing Trust, it would be essential that the royalty interests be derived from proven and producing oil and/or gas properties such as the State's oil royalty interest in the Prudhoe Bay Field. Furthermore, it would be necessary that the reserves attributed to the State's royalty interest and the timing of their productivity would be confirmed by a recognized independent petroleum engineering firm. These are important requirements, since the Financing Trust would be relying solely on the value of the reserves, and not the direct use of any State financial credit, for the recoupment of its investment and return thereon.

While this method of financing would be similar in certain respects to "production payment" financing in that the oil and gas reserves would be the only security for the financing, the Financing Trust has several significant

differences. It is possible that significantly more capital could be raised per equivalent barrel of reserves because the royalty interests represent "economic interests" in the reserves. The economic interest aspect of the royalties entitles the owners to receive all proceeds from price increases in the oil or gas attributable to their interests; this is not the case in a production payment where a fixed principal sum and interest rate are employed. Production payments usually require an approximate two times present value coverage of the principal amount of the production payment. Furthermore, the royalty interests would participate proportionately in any increase in the future reserves to be produced from the properties from which the royalty interests have been derived; this is not the case in any production payment financing. The use of a production payment does, however, limit the cost of the financing to the fixed interest rate included in the payment.

The concept of utilizing the Financing Trust as a possible method of financing all or portions of the System has been created specifically for this potential project. As such, the ultimate amount of capital which could be raised by this technique cannot be stated with complete certainty. It may be necessary to canvas a few potential institutional buyers before the ultimate potential magnitude of financing

could be more accurately estimated. We have sufficient confidence, however, to estimate that an initial amount of approximately $100 million could be arranged. Because of the sophisticated nature of the Financing Trust concept, the initial amount should be arranged privately from institutions rather than publicly from individuals. Larger amounts on an annual basis, including public offerings, may be possible after the initial increment has been accomplished and seasoned in the securities market.

The utilization of the Financing Trust would not detract from the ability to provide oil or gas for sale to industrial companies or users because the Trust would be receiving cash income for its royalty interests rather than receiving its value in kind. The price to be received for oil and gas by the Financing Trust would be the same that would otherwise accrue to the State with the possible exception that the Trust would not be in a position to provide reduced prices for the oil or gas to assist in the attraction of industry to the State.

Unless the proceeds to be received by the State from the sale of the royalty interests either were provided on a loan basis to private taxable interests owning the System, or were utilized to construct the facilities for leasing or installment sale to private taxable interests utilizing the

system, the Financing Trust would not result in the utilization of depreciation benefits or investment tax credits available from the System.

The State would be entitled to revenues from charges for conditioning and transmission services in those cases where the State utilized the proceeds from the sale of royalty interests to finance its ownership of the System facilities. In addition, the State would be entitled to the revenues from the sale of the royalty gas (with the exception of any revenues received therefrom by the Financing Trust) and from taxes levied on new businesses locating in the State. Taxes may be levied, as well, on the System facilities and the earnings of private interest owners in those cases where the State utilized the proceeds from the sale of the royalty interests to finance or assist in the financing of private interest ownership of the System facilities.

The degree to which the State would be required to maintain the responsibility for management and operation of the System would depend on the method of ownership and financing resulting from the proceeds from the sale of the royalty interests. As in previously discussed State ownership cases, it would be possible for the State to contract with private interests for the management and operation of the System.

To the extent that the Financing Trust alternative is used to finance System facilities, the State's financial credit

is not utilized through either general obligation indebtedness or State-guaranteed revenue bonds. Future income from the royalty interests is foregone, however, as a result of their sale at an acceptable price.

The extent to which new State legislation and/or constitutional amendments would be necessary to establish and implement the Financing Trust is in the process of being reviewed by counsel to the State.

Tab 5 - Other Forms of Ownership and Financing

We have been asked to review an alternative for ownership and financing of the System submitted to the State of Alaska and known as the Kelso Plan (the "Plan"), which provides for joint ownership of the System by a private existing gas utility and a General Stock Ownership Trust ("GSOP") representing shares of beneficial interest in the System owned by Alaska residents. We have segregated this financing and ownership alternative in part because it differs from the other generic categories which have been utilized in this report, as well as because we have serious reservations with respect to its financial viability.

Under the Plan, the System would be 25% owned by a private gas utility, and 75% owned by the GSOP. The 75% investment of the GSOP would be capitalized from the proceeds of notes sold to a consortium of lending institutions, with such notes guaranteed by the newly created System. Further security for the loan by the institutions to the GSOP would be provided by the willingness of the Federal Reserve Bank to purchase the guaranteed notes at a slight discount to cover the Bank's administrative costs in connection with servicing the notes. Thereafter, the System would make payments to the GSOP from revenues received in connection with the sale of gas to industrial users with such payments passed on to the Federal Reserve Bank. Remaining net revenues would be distributed to the shareholders in the System, who include the private utility and Alaska residents participating in the GSOP.

If successful, this form of financing would provide for widespread ownership of the System among Alaska residents through the vehicle of the GSOP, without a requirement for actual cash investment in the facilities for such ownership. As owners of a privately financed facility, the benefits of depreciation and investment tax credits would indirectly accrue to the owners of the System through the increase in after-tax net earnings that will result from the use of such tax benefits.

An analysis of the structure of this form of financing indicates that the key element of security rests with the willingness of the Federal Reserve Bank to agree to purchase the System-guaranteed notes from the consortium of lending institutions. Without such an agreement on the part of the Bank, it is extremely unlikely that lenders would willingly invest in the GSOP, even with the guarantee of the loan by the System. This is especially true given the fact that the System, upon making the guarantee, would have no operating history, and no assets.

We have discussed the Plan with the Federal Reserve Bank of New York, and representatives of the Bank have commented that they would be unable to purchase the guaranteed notes from lending institutions. Where the Bank has purchased loans from commercial lenders in the past, such loans have been guaranteed by an agency of the U.S. Government, and this procedure was generally utilized only where a major industrial corporation was in imminent danger of defaulting on loans of considerable size.

Assuming that the State of Alaska would be willing to guarantee the notes offered to capitalize the GSOP, the presence of such guarantee would obviate the need to rely on the Federal Reserve Bank, since State-guaranteed notes would be attractive to existing capital markets. We have previously presented numerous alternatives for the use of debt obligations guaranteed by the State of Alaska elsewhere in this report. These options suggest workable means of providing revenues to the State, as well as revenues for distribution to Alaska residents from a gas conditioning and transmission system which is financed on either taxable or tax-exempt bases.

Tab 6 - Alaska Royalty Gas Trust

The Alaska Royalty Gas Trust (the "Gas Trust") is an entity which would make available specified percentages of certain of Alaska's gas and/or oil royalty interests to State residents. The Gas Trust would be distinct and separate from the Financing Trust described in Tab 4. The primary function of the Financing Trust would be to finance or participate in the financing of System facilities. By contrast, the purpose of the Gas Trust would be to provide a mechanism for the amalgamation and periodic distribution of revenues received from the sale of royalty oil or gas to the residents of the State. In addition, as discussed more fully below, the royalty interests owned by the Gas Trust would be derived from "unproven" properties whereas the royalty interests owned by the Financing Trust would be derived from "proven and producing" properties.

In addition to Gas Trust revenues, excess revenues otherwise derived by the State from the ownership or taxation of the gas conditioning and transmission facilities could be made available for direct distribution to Alaska residents, as set forth in previous sections.

The Gas Trust would be a "grantor trust" and would be entirely separate from the State. The State would permanently transfer specified percentages of its gas and/or oil royalty interests on designated "unproven" oil and gas leases to the Gas Trust. The trustee(s) of the Gas Trust would be independent from the State

and would be experienced in performing the administrative and other functions of a trustee. It would be important for the trustee to be sophisticated in oil and gas matters, and a number of commercial banks could qualify for this role. The functions of the trustee(s) would include the collection of funds, investment thereof pending distribution, and the ultimate distribution of revenues to State residents from the sale of gas transferred to the Trust.

The beneficial owners of the Gas Trust certificates of ownership would be the residents of the State. Depending on the extent to which a secondary trading market is desired for the Gas Trust certificates, the development of specific requirements for the definition of a State resident would be necessary. Furthermore, the need for registration of the Gas Trust certificates with the Securities and Exchange Commission, and the State of Alaska or other states, would depend upon the extent to which widespread marketability for the certificates is sought.

The specific percentages of the State's royalty interests transferred to the Gas Trust and the properties from which they should be derived should be the subject of a separate, detailed study. The primary consideration of this study would be to assure an appropriate balance between the State's revenue requirements and funds available for distribution to the residents.

The utilization of the Gas Trust as a vehicle to combine and distribute portions of royalty revenue to the residents has the

potential of providing certain tax benefits which would not otherwise be available to the State or its residents.

A trust of the type envisioned would be considered a passthrough entity for Federal income tax purposes and, as such, would not be a taxable entity; the income received by the Gas Trust would be taxable only to the beneficial owners of the Trust (the State residents). This approach provides for distribution of income without the incidence of double taxation which would arise if a corporate entity were organized for the same purpose.

The Gas Trust also provides the potential to utilize percentage depletion, a tax benefit available to investors in oil and gas properties. Depletion is not available to the State as a tax-exempt entity, nor would it be available to the residents as a result of any direct cash distributions which were not related to a direct assignment of an "economic interest" in oil and gas or other mineral properties. Pending review by counsel, we believe that the transfer of a portion of the State's royalty interests to the Gas Trust would be an appropriate transfer of an economic interest in oil and gas properties. Thus, it is also envisioned that each resident, by virtue of his beneficial ownership of the Gas Trust's royalty interests, would be entitled to this tax benefit.

The effect of the depletion allowance on the reported earnings of participants in the Trust is similar to the effect of depreciation on the reported income of a private corporation: it provides a partial "shelter" from Federal taxation of income. For example, in

1978 when, as the table below indicates, the depletion allowance on oil and/or gas properties is 22%, participants in the Trust would be entitled to declare a pre-tax expense against their income equal to 22% of their earnings from the Trust. The resulting shelter from Federal taxation effectively increases the yield on income from the Trust on an after-tax basis.

The availability of the percentage depletion allowance is subject to the currently effective decline in the amount of depletion which will be granted beyond 1978 and the limitation on each resident's share of average daily production. The decline in the percentage depletion rate will be as follows:

Production During Year	Applicable Percentage
1978	22%
1979	22
1980	22
1981	20
1982	18
1983	16
1984 and thereafter	15

The limitation on each taxpayer's share of average daily oil and gas production to which the above percentages apply will be as follows:

Production During Year	Average Daily Quantity	
	Barrels of Oil	Mcf's. of Gas
1978	1,400	8,400
1979	1,200	7,200
1930 and thereafter	1,000	6,000

There is a further limitation on percentage depletion which provides that the depletion deduction for a taxable year cannot exceed 65% of the taxpayer's taxable income for the year computed, without regard to the depletion amount.

As indicated, the availability of the depletion allowance will increase the resident's after-tax retention of income distributions, or in the alternative, reduce the amount of royalty which would be necessary to provide the same after-tax income to the residents as would be provided by direct cash distributions from the State.

While further tax research would be necessary, and a tax ruling on specific aspects may be advisable, the preliminary advice of counsel has been that (a) the distribution of the Gas Trust certificates to the residents has a high probability of being non-taxable to the residents, and (b) the percentage depletion, subject to the limitations indicated above, would be available to the residents even though they would have no cost or tax basis on their respective interests at the time of issuance.

If the royalty interests transferred to the Gas Trust were on any proven oil and gas properties, problems may arise with respect to the use of depletion. Income attributable to such production could not be taken into account for any computation of percentage depletion by the residents. The proposed Regulations relating to limitations on percentage depletion on oil and gas property, as set forth in the Tax Reduction Act of 1975 and the Tax Reform Act of 1976, define a property as proven if "...its principal value has

been demonstrated by prospecting, exploration, or discovery work. The principal value of the property has been demonstrated by prospecting, exploration, or discovery work only if at the time of the transfer: (1) any oil or gas has been produced from a deposit, whether or not produced by the taxpayer or from the property transferred; (2) prospecting, exploration, or discovery work indicate that it is probable that the property will have gross income from oil or gas from such deposit sufficient to justify development of the property; and, (3) the fair market value of the property is 50 percent or more of the fair market value of the property, minus actual expenses of the transferee for equipment and intangible drilling and development costs, at the time of the first production from the property subsequent to the transfer and before the transferee himself transfers his interest."

Thus, the transfer of royalty interests would be limited to "unproven" properties in order to use the depletion allowance in connection with the Royalty Gas Trust. This tax regulation is still proposed and should not at this time rule out the consideration of proposed royalty transfers until such transfers have been reviewed on a case-by-case basis.

In addition to the tax benefits outlined above, the Gas Trust is a vehicle which can relieve the State from adding additional administrative personnel; the use of an experienced independent trustee(s) can reduce the cost of administration and the potential for political conflict.

It is possible that the Gas Trust concept could be adapted to participate in one or more of the ownership and financing options set forth in the prior sections of this report. For example, a portion of the income to be received by the residents from the Gas Trust could be applied to the purchase of common stock in an entity such as the one described under Tab 3-B. Such an adaptation would provide an opportunity for the residents to directly participate in the gas conditioning and transportation facilities as well as the royalty.

Counsel to the State is in the process of reviewing the existence of constitutional and/or legislative authority for the State to establish and implement the Gas Trust concept.

Alaska Royalty Gas Study

Comparative Evaluation of Alternative Forms of Financing and Ownership of Royalty Gas System (1)

Financing Proposals	Interest Rate on Debt Issued Under Financing Alternative	Ability to Utilize Depreciation and Investment Tax Credits	Source of Revenues to the State(2)	Mechanism for Distribution of Revenues to Qualified Alaska Residents	Required Use of State Credit and/or State Guarantees of Completion and Indebtedness	Requirements for New Legislation and New Administrative Structures for Management	Other
Ownership and Financing by the State.							
1A Financing by General Obligation Bonding	This form of tax-exempt financing has the lowest interest rate available. (Exception could be highly rated private corporation which utilizes tax-exempt industrial development bonds).	Provides no opportunity for use of tax benefits.	State derives revenues from all three sources, including wellhead price of the gas, charges for conditioning and transmission, and taxes on increased industry in the State.	Distribution accomplished through tax reductions for State residents and/or direct cash payments.	General obligation bonding is a full-faith and credit obligation of the State, and has the greatest use of State credit. No further guarantees required.	Will require enabling legislation to empower investment and ownership by the State. State has responsibility for management of the System and can contract for management.	Gas must be distributed on a basis compatible with the Internal Revenue Code.
1B Financing by Revenue Bonding	This form of tax-exempt financing has a higher interest rate than general obligation debt, but is generally lower than any form of taxable debt. (Exception could be a highly rated private corporation which utilizes tax-exempt industrial development bonds).	Provides no opportunity for use of tax benefits.	State derives revenues from all three sources, including wellhead price of the gas, charges for conditioning and transmission, and taxes on increased industry in the State.	Distribution accomplished through tax reductions for State residents and/or direct cash payments. If authority issues revenue bonds, net revenues after payment of debt service could be passed to State for distribution.	State will be required to guarantee completion of System, and may guarantee revenue bonds directly, or through throughput contracts or guarantee of bond reserve funds. Revenue bonding is not a charge against the State's ad valorem taxing capacity.	Will require enabling legislation to empower investment and ownership by the State or an authority. State or an authority has responsibility for management, and can contract for management.	Gas must be distributed on a basis compatible with the Internal Revenue Code.
1C Initial Financing through General Obligation Bonding - Subsequent Financing by Revenue Bonding	Tax-exempt short-term general obligation bonding will provide lower cost of debt for construction of facilities. Subsequent revenue bond debt will have low, tax-exempt interest rate, but rate will vary according to performance of System during initial operating period.	Provides no opportunity for use of tax benefits.	State derives revenues from all three sources, including wellhead price of royalty gas, charges for conditioning and transmission, and taxes based on increased industry in the State.	Distribution accomplished through tax reductions for State residents and/or direct cash payments. If authority issues revenue bonds, net revenues after payment of debt service could be passed to State for distribution.	Construction and interim period financing is a full-faith and credit obligation of the State. Depending upon System's operating performance prior to refinancing, guarantees may be required on revenue bonds issued for the refinancing.	Will require enabling legislation to empower investment and ownership by the State or an authority, during both phases of financing. State or an authority has responsibility for management, and can contract for management.	Gas must be distributed on a basis compatible with the Internal Revenue Code during both phases of financing.
Ownership and Financing by Private Interests							
2A Financing and Ownership by Private Corporation or Private Joint Venture	Use of privately-issued debt will result in a higher interest rate than on any form of tax-exempt financing. Utilization of tax benefits will reduce the effective after-tax cost of such debt, although not to a level below the cost of tax-exempt financing.	Provides for the full use of investment tax credits and depreciation benefits.	State derives revenues from sale of royalty gas to privately-owned System and from taxes levied on increased industry in State. Private investment alternatives provide greater present value benefits to the State by allowing it to achieve substantial revenues without investment.	Distribution accomplished through tax reductions and/or direct cash payments.	Private financing requires no use of State credit or guarantees. Must act in accordance with terms of gas supply contracts.	Requires no new legislation. Requires no operating responsibility on the part of the State.	Financing under this alternative will utilize taxable debt. No requirement to comply with Internal Revenue Code.
2B Financing and Ownership by Private Corporation or Private Joint Venture - Guarantee of Debt by Industrial Users or State of Alaska	Debt issued under this method of financing will be taxable, and will bear interest rate higher than tax-exempt debt, but lower than taxable debt issued without guarantee, depending upon credit of guarantor. Use of tax benefits will reduce the effective after-tax cost of such debt, although not to a level below the cost of tax-exempt financing.	Provides for the full use of investment tax credits and depreciation benefits.	State derives revenues from sale of royalty gas to privately-owned System and from taxes levied on increased industry in State. Private investment alternatives provide greater present value benefits to the State by allowing it to achieve substantial revenues without investment.	Distribution accomplished through tax reductions and/or direct cash payments from those sources of revenues available to the State.	State can guarantee debt directly or through the structure of gas supply contracts. If debt is guaranteed by industrial users, this alternative will not utilize the State's credit, although the State will be required to act in accordance with terms of gas supply contracts.	May require legislation to authorize State guarantee. Requires no operating responsibility on the part of the State.	No requirement for compliance with Internal Revenue Code. Use of guarantee by end-users will integrate such users into System. In return for such guarantee, price of gas to end-users may be reduced due to lower cost of taxable debt.

Notes:
(1) The analysis of alternatives contained herein applies solely to the operation of the System. The characteristics of the Alaska Royalty Gas Trust are discussed in Tab 6, and apply to all alternatives.
(2) The relative level of revenues provided to the State from all sources under each alternative will vary with respect to the structuring of the actual financing transaction and the policy decisions made by the State with respect to charges levied to industrial users for the royalty gas and conditioning and transmission services.
(3) This information applies only to the portion of funds derived from use of the Alaska Royalty Financing Trust alternative. Funds for State investment not obtained through the Financing Trust will have the same characteristics of the financing alternatives for State ownership elsewhere described in the study and on this matrix.

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Comparative Evaluation of Alternative Forms of Financing and Ownership of Royalty Gas System (1)

2C Industrial Development Bonding	The interest rate applicable to this form of tax-exempt financing will be lower than any form of taxable debt. Interest rate will be dependent upon credit of private corporation leasing or purchasing facilities and may be higher or lower than other forms of tax-exempt debt.	Transaction can be structured to allow use of depreciation and investment tax credit by private corporation leasing or purchasing system facilities or by third party lessors who lease the system to private corporation.	State derives revenues from sale of royalty gas and from taxes levied on the System as well as increased industry in State. Charges for conditioning and transportation of gas will accrue to private corporation(s) leasing or purchasing system facilities. Private investment alternatives provide greater present value benefits to the State by allowing it to achieve substantial revenues without investment.	Distribution accomplished through tax reductions and/or direct cash payments from those sources of revenues available to the State.	The lease agreement or installment sales contract should be structured to provide for a guarantee of the bonds by the lessee(s) or purchasers. If so structured, no use of State guarantee would be required.	Creation of authority empowered to issue industrial development bonds requires specific enabling legislation. Leasing or purchasing corporation has responsibility for management of System.	Gas must be distributed on a basis compatible with the Internal Revenue Code.
2D Initial Financing and Ownership of System by State - Subsequent Ownership by Private Interests	Initial construction financing through short-term, tax-exempt bonds has lowest interest rate available. Cost of long-term taxable debt for re-financing under private ownership will be higher than on any tax-exempt debt, although use of tax benefits will reduce after-tax cost of such debt.	Provides for the full use of investment tax credits and depreciation benefits during period of long-term ownership on private basis.	State derives revenues from sale of gas to privately owned System and from taxes on increased industry in State. Charges for conditioning and transmission accrue to private owners of System except during period of State ownership, when cash revenues will be received by State. Private investment alternatives provide greater present value benefits to the State by allowing it to achieve substantial revenues without investment.	Distribution accomplished through tax reductions and/or direct cash payments from those sources of revenues available to the State.	Requires use of State credit only during initial financing and construction period. No requirement for guarantees thereafter. However, if System does not prove successful during initial operating period, and cannot be transferred to private interests, State may be required to repay full amount of debt issued in connection with the facilities.	Will require enabling legislation for initial State investment. State would be responsible for operation of facilities only during initial operating period, and could contract for management during this period.	Under this alternative, end-users of royalty gas could be required to purchase shares of stock in private corporation, or guarantee debt of private corporation. Compliance with Internal Revenue Code required only during period of State investment.
Ownership and Financing by Joint State/Private Interests							
3A Combined Ownership and Financing by the State and Private Interests	Interest rate on debt under this approach will depend upon the form of financing utilized by the State and the relative proportion of public tax-exempt financing and private taxable financing. Overall cost of financing may be higher than where tax-exempt financing is solely utilized, but lower than where taxable financing is solely utilized. Use of tax benefits by private owner may further reduce overall cost of debt.	Provides for use of investment tax credits and depreciation benefits. If properly structued, such benefits can be utilized by private investors to a greater degree than their proportional ownership interest in the System.	State derives revenues from sale of gas to private participants in System, and from taxes levied on increased industry in State. State derives revenues from charges for transmission and conditioning in proportion to ownership interest in facility. Revenues also derived from taxation of System unless tax-exemption granted. Alternatives for partial private ownership allow present value of revenues achieved by the State to be higher than for alternatives for complete State ownership because of the requirement for a smaller State investment.	Distribution accomplished through tax reductions and/or direct cash payments from those sources of revenues available to the State.	Requires use of State credit for financing of portion of State ownership interest in facilities, either through general obligation bonding, or guarantees of completion and indebtedness if financed through revenue bonds. Depending upon credit of private investor, State may be required to further guarantee private debt.	Will require enabling legislative to empower State investment in a portion of the facilities. Responsibility for management of facilities could be assigned to private investor through operating agreement.	Under this alternative, end-users of royalty gas could be required to purchase shares of stock in private corporation, or guarantee debt of private corporation. Distribution of proportion of output represented by State ownership share must be made in a form compatible with Internal Revenue Code.
3B Joint Financing by the State and Alaska Residents	Initial financing accomplished through tax-exempt debt. Subsequent financings will use taxable debt.	Provides for use of investment tax credits and depreciation benefits.	State derives revenues from sale of gas to private participants in System, and from taxes levied on increased industry in State. State derives revenues from charges for transmission and conditioning in proportion to ownership interest in facility. Revenues also derived from taxation of System unless tax-exemption granted. Alternatives for partial private ownership allow present value of revenues achieved by the State to be higher than for alternatives for complete State ownership because of the requirement for a smaller State investment.	Distribution accomplished through tax reductions and/or direct cash payments from those sources of revenues available to the State. Alaska residents owning shares in corporation could additionally receive revenues from dividend payments on such shares.	Requires use of State credit for financings portion of facilities owned by State, either through general obligation bonds or guaranteed revenue bonds. State may also guarantee bank loans to resident investors to the extent required.	Will require enabling legislative to empower State investment in a portion of the facilities. Responsibility for management of facilities could be assigned to private investor through operating agreement.	Method makes available opportunity for investment by Alaska residents in Royalty Gas System, as well as Royalty Trust. Alternative approach would utilize private resident-owned corporation to construct facilities with debt guaranteed by State. Such debt would be taxable, and would have higher interest rate.
Alaska Royalty Financing Trust (3)	Funds obtained through this method are not borrowings, but rather are proceeds of sale of royalty rights. As such the funds do not bear interest.	Makes no provision for use of depreciation or investment tax credits. Potential use of depletion allowance will principally affect sale price of royalty rights to the Trust.	State will derive revenues from charges for conditioning and transmission of the gas, taxes on income of Trust certificate-holders, and taxes on increased industry. State will also derive revenues from the sale of gas not previously sold to Trust.	Revenues will be distributed in part through the Trust, and otherwise in the form of tax deductions or direct cash payments.	This alternative makes no use of the State's credit for funds obtained through the sale of royalty rights to the Trust	A review by counsel of required legislation pertaining to the Trust is currently pending.	In conjunction with the Alaska Royalty Gas Trust, use of this Trust represents an effective means of distributing the benefits of the State's royalty rights to Alaska residents.

Notes:
(1) The analysis of alternatives contained herein applies solely to the operation of the System. The characteristics of the Alaska Royalty Gas Trust are discussed in Tab 6, and apply to all alternatives.
(2) The relative level of revenues provided to the State from all sources under each alternative will vary with respect to the structuring of the actual financing transaction and the policy decisions made by the State with respect to charges levied to industrial users for the royalty gas and conditioning and transmission services.
(3) This information applies only to the portion of funds derived from use of the Alaska Royalty Financing Trust alternative. Funds for State investment not obtained through the Financing Trust will have the same characteristics of the financing alternatives for State ownership elsewhere described in the study and on this matrix.

AGO 545074

Appendix A

Regulations - Statutes Related to Tax-Exempt Financing

Interest on State Obligations

[¶ 947.0125]—Continued

• • *CCH Explanation*

obligation is a part may be invested in securities or other obligations which are part of a reasonably required reserve or replacement fund. This amount must not exceed 15% of the total issue proceeds.

Where the proceeds of an issue of governmental obligations are used to finance certain governmental programs, the obligations (subject to the limitations of Temporary Reg. § 13.4(b) at ¶ 991) may not be an arbitrage obligation. Arbitrage bonds are those whose proceeds are used to obtain other obligations or securities providing a "materially higher" yield than the interest, servicing, and other costs of the bonds themselves. Generally, interest paid on state and local government bonds is exempt from tax, but interest on arbitrage bonds issued by such governments is subject to tax. (Temporary Reg. § 13.4 at ¶ 991 (see also proposed Reg. § 1.103-13 at ¶ 992).)

.0127 **Qualified scholarship funding bonds.**—P. L. 94-455 added to Code Sec. 103 a provision exempting from taxation the interest on bonds issued by certain private non-profit corporations to finance college student loan programs. This exemption is effective with respect to obligations incurred on or after October 4, 1976.

Code Sec. 103(c)(5) provides that payments made by the U. S. Commissioner of Education (in the Department of Health, Education and Welfare) under the Emergency Insured Student Loan Act of 1969, P. L. 91-95, are to be omitted from computations of yields on student loan notes. This change is intended to assure that bonds issued by the non-profit corporations will not yield returns so high that the obligations would be non-exempt arbitrage bonds.

The exemption applies to obligations (called "qualified scholarship funding bonds," as defined in Code Sec. 103(e)) of non-profit corporations organized "at the request of" a state or political subdivision(s) of a state for the sole purpose of acquiring student loan notes incurred under the Higher Education Act of 1965, P. L. 89-329.

So that interest on the bonds of any of these corporations may be eligible for the exemption, all of the corporation's income (1) must accrue to the political entity responsible for the existence of the corporation, or (2) must be used to purchase more student loan notes. These requirements must be set forth in the corporate charter or enacted into state law.

.013 **Taxable after April 30, 1968.**—P. L. 90-364 changed the tax status of interest on industrial development bond issues of more than $1,000,000. Thus, interest on industrial development bond issues of more than $1,000,000 issued after April 30, 1968 is no longer exempt from tax. (But see .0157, below, for an elective provision whereby a governmental unit issuing industrial development bonds may increase the exemption to $5,000,000 for bonds issued after October 24, 1968.)

A bond is classed as an "industrial development bond" if:

(1) The obligation is part of an issue, all or a major portion (more than 25%) of the proceeds of which is used directly or indirectly

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Interest on State Obligations

• • *CCH Explanation*

in any trade or business of a person other than an exempt person (that is, a governmental unit or a religious, educational or charitable organization exempt from tax under Code Secs. 501(a) and 501(c)(3)), and

(2) Payment of the principal or interest on the obligation is, in whole or in major part, (a) secured by an interest in property (such as a factory, land, or equipment and machinery) used in a trade or business or in payments made (such as rent or lease or sales proceeds) in respect of this property, or (b) derived from payments in respect of property or borrowed money that is used (or is to be used) in a trade or business.

In determining the use to which the bond proceeds in (1) above are put, the indirect, as well as the direct, use of the proceeds is to be considered. Thus, if an exempt person uses the bond proceeds in a trade or business (such as a leasing business), the bond issue will meet the first requirement of the definition if the person borrowing the proceeds or leasing the property from the exempt person uses the property or bond proceeds in his trade or business. Similarly, the bond meets the requirements of (1), above, if an exempt person sells property acquired with the proceeds of a bond issue to other persons who, in turn, use the property in their trade or business.

It is not necessary, in order for (2), above, to apply, for the property meeting this element of the industrial development bond definition to be the same property referred to in (1), above; that is, the property securing payment need not be the same property for which the bonds are issued. The fact that the bond issue may also be secured by the full faith and credit of the governmental unit does not prevent a bond from being classified as an industrial development bond so long as payment of the obligation, in major part, also is secured by or is to be derived from the property or payments referred to in (2), above.

.014 Specific facilities exempted.—In addition to the exemption for bond issues of $1,000,000 or less (see .0155), the Regulations exempt interest on industrial development bonds from tax if substantially all of the bond proceeds are used to provide the following facilities:

(1) Residential real property for family units. This includes the construction of buildings containing facilities for living, sleeping, eating, cooking, and sanitation. Hotels, motels, dormitories, roominghouses, hospitals, rest homes, and trailer courts, for example, do not qualify. Residential real property is intended to include facilities which are functionally related and subordinate to the space used for family units. The fact that a minor portion of a facility is used for other nonfamily unit purposes (such as a laundromat or drugstore) will not foreclose exemption for the facility.

(2) Sports facilities, such as baseball and football stadiums, indoor sports arenas, swimming pools, golf courses, ski slopes, and tennis courts. Facilities directly related to exempt sports facilities are intended to be considered sports facilities for purposes of this exemption.

(3) Convention or trade show facilities. Only the special-purpose buildings and structures constructed for convention or trade shows

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Interest on State Obligations

[¶ 947.014]—Continued

• • *CCH Explanation*

qualify. This means, for example, that the exemption does not apply to bonds issued to finance a hotel, even though the hotel expects and does a major part of its business in catering to delegates or participants at conventions and trade shows.

(4) Airports, docks, wharves, mass commuting facilities, parking facilities, or storage or training facilities directly related to such facilities. A facility located at an airport for traning flight personnel exemplifies an exempt training facility. An exempt storage facility, for example, is a grain elevator adjoining a dock or wharf directly related to the dock facility.

(5) Public utility facilities used to provide sewage or solid waste disposal facilities, and facilities designed to furnish locally electric energy or gas.

(6) Air or water pollution control facilities. This means facilities designed to abate pollution that would be present if the facilities did not exist; industrial apparatus designed not to generate pollution *ab initio* does not qualify for bond interest exemption.

(7) Facilities for the furnishing of water if (for obligations issued after January 1, 1969) available on reasonable demand to members of the general public.

However, if the industrial development bonds used to finance the above facilities and those described at .015 and .0155 are held by a "substantial user" of the facilities constructed with the bond proceeds, interest on such bonds will be taxable. A "substantial user" is defined as any person who regularly uses a part of such facility in his trade or business.

A specific exception to industrial development bond treatment applies (under P. L. 94-164) to grant tax-exempt status to obligations issued to finance a dam furnishing water for irrigation purposes which has a subordinate use in connection with the generation of electric energy by water. The exemption applies if substantially all of the stored water is contractually available for release from the dam for irrigation purposes and if the water released is available on reasonable demand to members of the general public. This provision, which was enacted specifically to cover the reconstruction of the American Falls Dam in Idaho, applies to obligations issued after December 23, 1975.

.015 Industrial parks.—A special exemption from the general rule at .013, above, has been provided by P. L. 90-364 for bond issues where substantially all of the proceeds of the bond issue are to be used for the acquisition or development of land as the site for an industrial park. An industrial park, generally, is a series of sites for industrial plants (including wholesale and distributing plants) developed under an overall plan and usually subject to special zoning restrictions.

For purposes of this exemption, the term "development of land" includes providing water, sewage, and drainage facilities, road, rail-

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Interest on State Obligations

• • *CCH Explanation*

road, docking and other similar transportation facilities, and power or communication facilities. The term does not include the construction of buildings or other structures.

.0155 Bond issues of $1,000,000 or less.—A special exemption is provided by P. L. 90-364 for industrial development bonds which are part of issues of $1 million or less and where substantially all of the proceeds from the issue are used (1) to acquire, construct, reconstruct or improve land or depreciable property or (2) to redeem all or part of a prior bond issue which was issued to acquire the property described in (1), above. (See also .0157 for an elective provision whereby a governmental unit issuing industrial development bonds may increase the exemption to $5 million for bonds issued after October 24, 1968.)

The $1 million exemption is not applicable, however, if a substantial portion of the proceeds is loaned to a borrower for use as working capital or to finance inventory.

In determining whether a bond issue is within the $1 million exemption, the proceeds of outstanding prior issues, as well as issues of another governmental unit, regarding the principal user of the facility constructed with the proceeds of the first issue, are taken into account if the later facilities are located in the same incorporated municipality or located in the same county (but not in any incorporated municipality). (Neither the law nor the regulations define the terms "principal user" or "incorporated municipality," and there is no definite indication as to what construction the Internal Revenue Service gives to these terms. Thus, it is advisable for a taxpayer to seek a private ruling in connection with the proposed issuance of bonds to test whether such issue qualifies for the small issue exemption.)

Similarly, the determination of whether a bond issue is within the $5 million limit (.0157, below) includes any prior issue qualifying for exemption under Code Sec. 103(c) if the facilities financed by the prior issue and the facilities to be financed by the new issue are in the same county or municipality and the principal user (or related person) of both facilities is the same. In addition, all capital expenditures made by the principal user (or related person) within three years before and three years after the date of the new issue count toward the $5 million limit if they (1) were made for facilities located in the same county or municipality and used by the same principal user (or related person), (2) were not financed by the proceeds of outstanding prior exempt issues, and (3) were properly chargeable to capital account.

Example (1): County A and Corporation X contract for the county to provide a factory which X will lease for 20 years. Under the agreement (1) A will issue $1 million of bonds on November 1, 1977, (2) the bond proceeds will be used to purchase land in Town M and to construct and equip a factory in accordance with X's specifications, (3) X will rent the facility for 20 years at an annual rental equal to the amount necessary to amortize the principal and pay the interest on the outstanding bonds, and (4) the payments by X and the facility itself will be security for the bonds. Although the bonds issued qualify as industrial develop-

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Interest on State Obligations

[¶ 947.0155]—Continued

• • *CCH Explanation*

ment bonds under the rules at .013, interest on such bonds will be tax exempt by virtue of the $1 million bond exemption.

Example (2): Assume the same facts as in Example (1), above. After the bonds are issued, X proposes to Town M that the town build a $1 million facility in the town for X's use under terms similar to the factory arrangement. On the issue date of the new bond issue, $750,000 of the first issue of bonds are outstanding. When M issues new bonds for the facility, the issue will not qualify under the $1 million exemption since the prior outstanding issue of $750,000 must be taken into account; the facilities under both issues are located in Town M and the same taxpayer will be the principal user of the new warehouse, but Town M may elect to have the $5 million limit apply.

.0157 **Election of $5,000,000 exemption.**—In lieu of the $1 million exemption described at .0155, a governmental unit issuing industrial development bonds may elect to have a $5 million limit apply to an issue. This elective provision, added to the Code by P. L. 90-634, applies only to obligations issued after October 24, 1968. For the procedure to be followed in electing this exemption, see .0446 below.

In determining whether an issue qualifies under the $5 million election, a governmental unit must consider all outstanding prior issues which qualified for exemption. Any such prior issue must be counted as part of the $5 million test figure if the previously financed facilities and the facilities to be financed under the new issue are located in the same municipality or in the same county (but in an unincorporated area) and the principal user (or a related person) of both facilities is the same. The governmental unit must also consider all capital expenditures made by the principal user (or a related person) within three years before and three years after the date of the new bond issue. Such capital expenditures are to be taken into account in testing the $5 million limit if they (1) are made for facilities located in the same municipalty or in the same county (but in an unincorporated area) and used by the same principal user (or a related person), (2) are not financed by prior exempt issues, and (3) are properly chargeable to capital account.

If a capital expenditure is chargeable to capital account, it is to be counted toward the $5 million figure even though an elective provision is available under the Code which allows the expenditure to be deducted as a current expense. For example, research and experimental expenses are capital expenditures, but a taxpayer may elect, under Code Sec. 174, to treat them as deductions. Thus, if such expenses would otherwise qualify for inclusion in the $5 million test figure, they must be included even though the principal user (or a related person) elects to deduct them.

The following capital expenditures are not to be counted against the $5 million test figure:

(1) A capital expenditure made to replace property damaged or destroyed by fire, storm, or other casualty to the extent that the amount of the capital expenditure does not exceed in dollar

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• • *CCH Explanation*

amount the fair market value (determined immediately before the casualty) of the damaged or destroyed property.

(2) A capital expenditure required pursuant to a *post-issue* change in a federal or state law, or local ordinance, which is of general application.

(3) A capital expenditure required by circumstances which could not have reasonably been foreseen on the date on which the bond issue was issued or which arose out of a mistake of law or fact—such as where the principal user (or a related person) mistakenly treated an item as a deductible repair rather than as a capital expense. Under this exception, the total amount of expenditures not taken into account for the $5 million test figure may not exceed $250,000 ($1 million for expenditures incurred after December 10, 1971). Included in these expenditures are expenditures necessitated by erroneous cost estimates, by increases in costs due to inflation, strikes, delays, or architectural modifications but not increases due to expansions.

If the proceeds of a bond issue are to be used to redeem prior bond issues, the election of the $5,000,000 limit may be made only if all of the prior issues being redeemed are qualified exempt issues. But in applying the capital expenditures test to refinancing issues, capital expenditures are to be taken into account only for purposes of determining whether the prior issues subject to a $5,000,000 election qualified for exemption and would have continued to qualify but for the redemption.

If a bond issue qualifies under the $5 million exemption and later becomes disqualified due to the capital expenditure rule, the loss of the tax exemption for the interest on the bonds begins only as of the date on which the expenditure which caused the disqualification was paid or incurred.

.016 Does the U. S. Constitution permit federal taxation of interest on state obligations?—The exemption for interest on state and local governmental obligations results from what is, or what was thought to be, a constitutional injunction against federal taxation of such interest. It is true that the United States Supreme Court at one time indicated that an attempt by the United States to tax interest derived from securities issued by states or their political subdivisions would be unconstitutional (*National Life Insurance Co.*, .034, below). However, this decision was handed down in 1928 during the heyday of the doctrine of "implied immunity" of state and federal governments from taxation by each other. Since that time, the doctrine of implied immunity has eroded considerably. It received a crushing blow in 1939 by the U. S. Supreme Court's decision in *Graves v. O'Keefe*, .034, below, where it was stated that income of a state employee may be the subject of a nondiscriminatory federal income tax even though the employee has been paid out of state funds for services in connection with an essential governmental function of the state. No challenge, however, has been issued against the tax-exempt status of interest on state

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[¶ 947.016]—Continued

• • *CCH Explanation*

obligations, and Congress, until its recent move against industrial development bonds (see .012, above), has provided for the exemption of such interest for many years.

Special assessment certificates.—Obligations of a political subdivision include certificates for public improvements (such as sewers, sidewalks, and streets) which are evidence of special assessments against specific property, which assessments become a lien against the property and which the political subdivision is required to enforce (Reg. § 1.103-1). This is true even though the obligations are to be satisfied out of special funds and not out of general funds or taxes. Accordingly, the interest upon such obligations is exempt from tax. See also the cases at .14 et seq. below.

Interest on condemnation award.—The Tax Court and other courts have sustained the Commissioner's ruling that interest paid by a municipality upon a condemnation award is not exempt as interest from a State "obligation." See .03, below.

Notes.—Interest on notes of a political subdivision of a State was held to be tax-exempt in an early Tax Court opinion. The Second Circuit holds to the same effect. See .075 et seq., below.

The Treasury Department recognizes issue discount as being "interest" in substance. Therefore, if interest on a bond is wholly exempt from federal income taxes, any discount at which the bond is issued is also exempt. The nature of discount is not altered by the fact that part of it may be received before maturity of the bond issue. Consequently, where bonds are sold by the original or subsequent holders before redemption, each holder of the bond to the date of maturity is entitled to apportion the amount of discount at which the obligation was issued according to the period of his holding (.04 below).

But any premium received upon redemption of nontaxable bonds is not "interest." It is an amount received in exchange, and consequently is taxable income. Gain on the sale of such bonds, except to the extent that it represents discount, is also taxable income (.10, below). And any loss on sale or redemption is recognized and deductible, either as a loss from investment securities or as a business loss. See ¶ 1532.66 and 4748.02.

The taxing of gain derived from the sale of county or municipal bonds is not in violation of the Constitution, the Supreme Court held (*Bunn*, .10, below). The Tax Court held, however, that gain derived from the sale of certificates of indebtedness which had been accepted in lieu of interest on municipal obligations was not taxable, even though the certificates were transferred prior to maturity. The court said that, since the interest on the municipal obligations was tax-exempt, the fact that it was actually collected through subsequent disposal of an obligation intended merely to represent the interest was ineffectual to alter the fundamental nature of the income. (*Palm Beach Tr. Co.*, .10.)—CCH.

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Appendix B

Sample Authority Enabling Legislation

Chapter 56. Alaska Housing Finance Corporation.

Section		Section	
10.	Findings and purpose	110.	Bonds and notes
20.	Alaska Housing Finance Corporation	115.	Prohibited bidding on bonds and notes
30.	Corporation governing body	120.	Validity of any pledge
40.	Meetings of board	130.	Remedies
45.	Minutes of meetings	140.	Negotiable instruments
50.	Administration of affairs	150.	Obligations eligible for investment
55.	Legal advisor	160.	Refunding obligations
60.	Board may employ personnel	170.	Credit of state not pledged
70.	Personnel exempt from State Personnel Act	180.	Officers not liable
80.	Interdepartmental cooperation	190.	Tax exemption
85.	Investment of state surplus	200.	Annual report
90.	General powers	210.	Definitions
100.	Housing development fund		

Sec. 18.56.010. Findings and purpose. (a) There exists within the state a serious shortage of decent, safe and sanitary residential housing available at low or moderate prices or rentals to persons of lower and moderate income. There also exist within the state remote, underdeveloped or blighted areas where the development of decent, safe and sanitary housing is necessary to economic growth. These conditions are inimical to the safety, health, welfare and prosperity of the residents of the state and to the sound growth of urban and rural communities.

(b) The legislature finds and declares that private enterprise has not been able to provide, without assistance, an adequate supply of safe and sanitary homes at prices or rents which persons of lower or moderate income can afford, or to achieve rehabilitation of much of the present housing for persons of lower and moderate income, or to provide without assistance the housing necessary to promote the

economic growth of remote, underdeveloped or blighted areas, and that existing state and federal programs are inadequate to meet housing needs of persons of lower and moderate income or of remote, underdeveloped or blighted areas. It is imperative that the supply of housing for persons of lower and moderate income and the housing necessary to promote the economic growth of remote, underdeveloped or blighted areas be increased and that coordination and cooperation among private enterprise, state and local government be encouraged to sponsor, build and rehabilitate residential housing for these persons.

(c) The legislature finds and declares further that, in accomplishing this purpose, the creation of the Alaska Housing Finance Corporation is essential to assist in the acquisition and development of land and the construction, rehabilitation, financing, management, maintenance, sale and rental of dwelling units for persons of lower and moderate income or persons in remote, underdeveloped or blighted areas and that these activities serve a public purpose in benefiting the people of the state. The Alaska Housing Finance Corporation is empowered to act on behalf of the state and its people in serving this public purpose for the benefit of the general public. (§ 1 ch 107 SLA 1971; am § 1 ch 81 SLA 1972)

Effect of amendment. — The 1972 amendment, in subsection (a), inserted "or moderate" in the first sentence, inserted "and moderate" in that sentence, added the second sentence, and substituted "These conditions are" for "This shortage is" at the beginning of the third sentence. In the first sentence of subsection (b), the amendment inserted "and moderate" in three places, inserted "or to provide without assistance the housing necessary to promote the economic growth of remote, underdeveloped or blighted areas," inserted "state and," and inserted "or of remote, underdeveloped or blighted areas." In the second sentence of subsection (b), the amendment inserted "and moderate" and inserted "and the housing necessary to promote the economic growth of remote, underdeveloped or blighted areas." In the first sentence of subsection (c), the amendment inserted "and moderate" and "or persons in remote, underdeveloped or blighted areas."

Legislative committee report. — For report on ch. 81, SLA 1972 (CSHB 547), see 1972 House Journal, p. 859.

Sec. 18.56.020. Alaska Housing Finance Corporation. The Alaska Housing Finance Corporation is a public corporation and government instrumentality within the Department of Commerce, but having a legal existence independent of and separate from the state. The corporation may not be terminated as long as it has bonds, notes or other obligations outstanding. Upon termination of the corporation, its rights and property pass to the state. (§ 1 ch 107 SLA 1971)

Sec. 18.56.030. Corporation governing body. The corporation shall be governed by a board of directors, consisting of the commissioner of commerce and four members appointed by the governor. Members serve without compensation except that each member may be reimbursed by the corporation for actual and necessary expenses at the same rate as set out in AS 39.20.180. (§ 1 ch 107 SLA 1971)

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Sec. 18.56.040. Meetings of board. The board shall elect a chairman from among its membership at its first meeting in each year. A majority of the members constitute a quorum for organizing the board, conducting its business and exercising the powers of the corporation. The board shall meet at the call of its chairman. The board shall meet not less than once each three months. (§ 1 ch 107 SLA 1971)

Sec. 18.56.045. Minutes of meetings. The board shall keep minutes of each meeting and send a certified copy to the governor. (§ 1 ch 107 SLA 1971)

Sec. 18.56.050. Administration of affairs. The board may manage the assets and business of the corporation and prescribe, amend and repeal bylaws, rules and regulations governing the manner in which the business of the corporation is conducted and the manner in which its powers are exercised. The board may delegate to one or more of its directors, officers, agents or employees those powers and duties it considers proper. The board may delegate supervision of the administration of the corporation to an executive officer. (§ 1 ch 107 SLA 1971)

Sec. 18.56.055. Legal advisor. The attorney general is the legal counsel for the corporation. He shall advise the corporation in legal matters and represent it in suits. (§ 1 ch 107 SLA 1971)

Sec. 18.56.060. Board may employ personnel. The board may appoint other officers, hire employees and agents, and engage professional and technical advisors as employees or as independent contractors. The board shall prescribe the duties and compensation of corporation personnel. (§ 1 ch 107 SLA 1971)

Sec. 18.56.070. Personnel exempt from State Personnel Act. The personnel of the corporation are exempt from AS 39.25 to the same extent as the personnel of the Alaska State Housing Authority. (§ 1 ch 107 SLA 1971)

Sec. 18.56.080. Interdepartmental cooperation. All departments, agencies and public corporations of the state may provide information, services, facilities and loans to the corporation upon its request. The corporation may reimburse departments, agencies and public corporations of the state for loans advanced or for expenses incurred on the corporation's behalf. (§ 1 ch 107 SLA 1971)

Sec. 18.56.085. Investment of state surplus. Notwithstanding other provisions of law, when the commissioner of revenue determines that there is in the state treasury a surplus above an amount sufficient to meet current cash expenditure needs, the surplus may be invested, in addition to the investments permitted by AS 37.10.070(a), in residential mortgages owned by the corporation and secured by real estate within the state, which investments shall be subject to the terms

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and conditions that the corporation and the commissioner of revenue may provide in any contract of sale. Investments allowed by this section shall be made as provided for other investments of the state money under AS 37.10.070(a), (f), (g) and (i). The terms and conditions of any contract of sale authorized to be made under this section may include but are not limited to:

(1) the investment by the state in a specified or determinable amount of mortgages;

(2) the existence of a prior lien on and pledge of the mortgages invested in by the state;

(3) provisions relating to the subordination of the state's interest in and application of annual payments of principal and interest or the proceeds of a permitted sale of, or insurance or prepayments on, the mortgages; and

(4) the right of the corporation to repurchase the mortgages at a predetermined price. (§ 2 ch 81 SLA 1972)

Legislative committee report. — For report on ch. 81, SLA 1972 (CSHB 547), see 1972 House Journal, p. 859.

Sec. 18.56.090. General powers. In addition to other powers granted in this chapter, the corporation may, for the purpose of providing housing for persons of lower and moderate income or persons located in remote, underdeveloped or blighted areas of the state

(1) make or participate in the making of construction loans to sponsors, developers and builders of land development or residential housing, if the corporation determines that construction loans are not otherwise available, wholly or in part, from private lenders upon reasonably equivalent terms and conditions;

(2) make or participate in the making of mortgage loans to sponsors, developers, builders and purchasers of residential housing, if the corporation determines that mortgage loans are not otherwise available, wholly or in part, from private lenders upon reasonably equivalent terms and conditions;

(3) purchase or participate in the purchase of mortgage loans made to sponsors, developers, builders, owners and purchasers of residential housing, if the corporation

(A) has given approval before the initial making of the loan and has determined that mortgage loans were, at the time the approval was given, not otherwise available, wholly or in part, from private lenders upon reasonably equivalent terms and conditions, or

(B) has determined that the purchase or participation will result in additional residential housing, taking into account without limitation such factors as reinvestment of the proceeds of the sale in additional mortgage loans, increased availability of mortgage loans insured by the federal government, its agencies or departments, the reduction, if any, of interest payments to be made with respect to mortgage loans, or

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such other factors as will tend to increase or improve the supply of residential housing within the state;

(4) make partial rental payments and mortgage interest payments under a contract with any housing owner if the payments will be applied to decrease rental or mortgage interest charges of persons of lower and moderate income or owners or purchasers of residential housing in remote, underdeveloped or blighted areas of the state;

(5) make loans from the housing development fund;

(6) collect and pay reasonable fees and charges in connection with making, purchasing and servicing its loans, notes, bonds, commitments and other evidences of indebtedness;

(7) acquire real property, or any interest in real property, in its own name, by purchase, transfer or foreclosure, when the acquisition is necessary or appropriate to protect any loan in which the corporation has an interest; sell, transfer and convey any such property to a buyer; and, if the sale, transfer or conveyance cannot be effected with reasonable promptness or at a reasonable price, rent or lease the property to a tenant pending the sale, transfer or conveyance;

(8) sell, at public or private sale, to any purchaser, including the Federal National Mortgage Association, all or any part of a mortgage or other instrument or document securing a construction, land development, mortgage or temporary loan of any type permitted by this chapter;

(9) purchase, in order to meet the requirements of the sale of its mortgages to the Federal National Mortgage Association, stock of the Federal National Mortgage Association;

(10) procure insurance against any loss in connection with its operation;

(11) consent to the modification of the rate of interest, time of payment of any installment of principal or interest, or any other terms, of the mortgage loan, mortgage loan commitment, construction loan, temporary loan, contract or agreement of any kind to which the corporation is a party;

(12) borrow money as herein provided to carry out and effectuate its corporate purposes; and issue its obligations as evidence of any such borrowing;

(13) include in any borrowing the amounts necessary to pay financing charges, interest on the obligations for a period not exceeding one year after the date on which the corporation estimates funds will otherwise be available to pay the interest, consultant, advisory and legal fees and such other expenses as are necessary or incident to this borrowing;

(14) make and publish rules and regulations respecting its lending programs and such other rules and regulations as are necessary to effectuate its purposes;

(15) provide technical and advisory services to sponsors, builders and developers of residential housing and to residents of it;

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(16) promote research and development in scientific methods of constructing low-cost residential housing of high durability;

(17) make and execute agreements, contracts and other instruments necessary or convenient in the exercise of the powers and functions of the corporation under this chapter, including contracts with any person, firm, corporation, governmental agency or other entity;

(18) receive, administer and comply with the conditions and requirements respecting any appropriation or gift, grant or donation of property or money;

(19) sue and be sued in its own name;

(20) adopt an official seal;

(21) adopt bylaws for the regulation of its affairs and the conduct of its business and prescribe rules, regulations and policies in connection with the performance of its functions and duties;

(22) employ fiscal consultants, engineers, attorneys, real estate counselors, appraisers and such other consultants and employees as may be required in the judgment of the corporation, and fix and pay their compensation from funds available to the corporation;

(23) do all acts and things necessary, convenient or desirable to carry out the powers expressly granted or necessarily implied in this chapter;

(24) invest or reinvest, subject to its contracts with noteholders and bondholders, any money or funds held by the corporation in any obligations or other securities or investments in which banks or trust companies in the state may legally invest funds held in reserves or sinking funds or any funds not required for immediate disbursement, and in certificates of deposit or time deposits secured by obligations of, or guaranteed by, the state or the United States of America. (§ 1 ch 107 SLA 1971; am § 3 ch 81 SLA 1972)

Effect of amendment. — The 1972 amendment inserted "and moderate" and "or persons located in remote, underdeveloped or blighted areas of the state" in the introductory language, rewrote paragraph (3), inserted "and moderate" and "or owners or purchasers of residential housing in remote, underdeveloped or blighted areas of the state" in paragraph (4) and added paragraph (24).

Legislative committee report. — For report on ch. 81, SLA 1972 (CSHB 547), see 1972 House Journal, p. 859.

Sec. 18.56.100. Housing development fund. (a) There is created a special revolving loan fund to be known as the "housing development fund" to be administered by the corporation as a trust fund separate and distinct from any other money or funds administered by the corporation.

(b) Consistent with § 90 of this chapter, the corporation may make temporary and permanent loans from the housing development fund, at such interest rate or rates as determined by the corporation, and with such security for repayment as is necessary and practicable, to

(1) defray development costs of sponsors, builders, and developers of residential housing;

(2) provide to persons of lower and moderate income who are applying for mortgages, the amounts required to make down payments

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and pay closing costs and to housing owners the amounts applied for partial rental payments and mortgage interest payments under § 90(4) of this chapter; or

(3) purchase, make, or participate in the making of mortgage and construction loans which are not federally insured or guaranteed to sponsors, builders, purchasers and developers of land development or residential housing, if the corporation determines that such loans are not otherwise available, wholly or in part, from private lenders upon reasonably equivalent terms and conditions.

(c) To the credit of the housing development fund shall be deposited

(1) grants and contributions to the fund and the proceeds of sale of fund notes; and

(2) all receipts of the corporation on account of repayment of or sale or other disposition of the security for any loans made under (b) of this section.

(d) The corporation may receive and accept from any source whatever any grants or contributions for the housing development fund.

(e) The corporation may provide for the issuance, at one time or from time to time, of housing development fund notes for the purpose of providing funds for the fund. The commissioner of revenue is authorized to purchase fund notes with surplus funds in the state treasury. Before submission of the executive budget to the legislature, the commissioner of revenue shall annually recommend to the governor the anticipated amounts of surplus funds available for purchase of fund notes in the fiscal year encompassed by the budget. In making his recommendation to the governor, the commissioner of revenue shall consider the expenditure and revenue projections contained in the most recent revenue source document prepared for and submitted to the legislature by the administration. If the governor agrees with the recommendation of the commissioner of revenue he shall forward the recommendation to the corporation.

(f) The principal and interest on fund notes is payable solely from the housing development fund. The corporation shall determine the date of the fund notes of each issue, the maturity of the notes, the redemption provisions, if any, including redemption prices, terms and conditions, the form and manner of execution of the notes, including any interest coupons to be attached to them, the denomination and the place of payment of principal and interest, which may be any bank, trust company, or agent, including the purchaser of any fund notes. The fund notes may be issued in coupon or in registered form, or both. The corporation may provide for the registration of any coupon fund notes as to principal or interest, or both, and for the reconversion into coupon fund notes of any fund notes registered as to both principal and interest, and for the exchange of registered and coupon fund notes. The corporation may provide for the replacement of fund notes which are mutilated, destroyed, lost or stolen.

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(g) Fund notes shall bear interest at the rate, and shall be sold in the manner and for the price the corporation determines.

(h) If an officer whose signature or a facsimile of whose signature appears on any fund notes or coupons attached to them ceases to be an officer before the delivery of the fund notes or coupons, his signature or facsimile is valid for all purposes as if he had remained in office until delivery.

(i) The proceeds of sale of fund notes shall be used solely for the purposes for which issued and shall be disbursed in the manner and under the restrictions the corporation provides in the resolution authorizing the issuance of the fund notes.

(j) Fund notes may be issued without the consent of any government agency and without any other proceedings or conditions other than those which are specifically required by this chapter and the provisions of the resolution authorizing the issuance of the fund notes.

(k) No loan may be made by the corporation from the housing development fund except in accordance with a written agreement which shall include, but need not be limited to, the following terms and conditions:

(1) the proceeds of loans shall be used only for the purposes for which the loan is made, as provided in the agreement;

(2) the loan shall be repaid in full as provided in the agreement;

(3) all repayments in connection with a loan to defray development costs shall be made concurrent with receipt by the borrower of the proceeds of a construction loan or mortgage loan, or at such other times as the corporation considers reasonably necessary or practicable; and

(4) security for repayment shall be specified and shall be upon terms and conditions as the corporation considers necessary or practicable to insure all repayments. (§ 1 ch 107 SLA 1971; am § 4 ch 81 SLA 1972)

Effect of amendment. — The 1972 amendment inserted "and moderate" in subsection (b)(2).

Legislative committee report. — For report on ch. 81, SLA 1972 (CSHB 547), see 1972 House Journal, p. 859.

Sec. 18.56.110. Bonds and notes. (a) The corporation, by resolution, may issue bonds and bond anticipation notes in order to provide funds to carry out and effectuate its purposes.

(b) The principal and interest on these bonds or notes is payable from corporation funds, excluding funds in the housing development fund. Bond anticipation notes may be payable from the proceeds of the sale of bonds or from the proceeds of sale of other bond anticipation notes or, in the event bond or bond anticipation note proceeds are not available, such notes may be paid from other funds or assets of the corporation. Bonds or notes may be additionally secured by a pledge of a grant or contribution from the federal government, or a corporation, association, institution or person, or a pledge of money, income, or revenues of the corporation from any source.

(c) Bonds or bond anticipation notes may be issued in one or more series and shall be dated, bear interest at the rate or rates per year or

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within the maximum rate, be in the denomination, be in the form, either coupon or registered, carry the conversion or registration provisions, have the rank or priority, be executed in the manner and form, be payable from the sources in the medium of payment and place or places within or outside the state, be subject to authentication by a trustee or fiscal agent, and be subject to the terms of redemption with or without premium, as the resolution of the corporation may provide. Bond anticipation notes shall mature at such time or times as may be determined by the corporation. Bonds shall mature at such time, not exceeding 50 years from their date, as may be determined by the corporation. Before the preparation of definitive bonds or bond anticipation notes, the corporation may issue interim receipts or temporary bonds or bond anticipation notes, with or without coupons, exchangeable for bonds or bond anticipation notes when these definitive bonds or bond anticipation notes have been executed and are available for delivery.

(d) Bonds or bond anticipation notes may be sold in the manner, on the terms and at the price the corporation determines.

(e) If an officer whose signature or a facsimile of whose signature appears on any bonds or notes or coupons attached to them ceases to be an officer before the delivery of the bond, note or coupon, his signature or facsimile is valid the same as if he had remained in office until delivery.

(f) In any resolution of the corporation authorizing or relating to the issuance of bonds or bond anticipation notes, the corporation has power by provisions in the resolution which will constitute covenants of the corporation and contracts with the holders of the bonds or bond anticipation notes

(1) to pledge to any payment or purpose all or any part of its revenues to which its right then exists or may thereafter come into existence, and the money derived from the revenues, and the proceeds of any bonds or notes;

(2) to covenant against pledging all or any part of its revenues, or against permitting or suffering a lien on the revenues or its property;

(3) to covenant as to the use and disposition of any and all payments of principal or interest received by the corporation on mortgage loans, construction loans or other investments held by the corporation;

(4) to covenant as to establishment of reserves or sinking funds and the making of provision for and the regulation and disposition of the reserves or sinking funds;

(5) to covenant with respect to or against limitations on a right to sell or otherwise dispose of property of any kind;

(6) to covenant as to bonds and notes to be issued, and their limitations, terms and conditions, and as to the custody, application and disposition of the proceeds of the bonds and notes;

(7) to covenant as to the issuance of additional bonds or notes, or as to

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limitations on the issuance of additional bonds or notes and the incurring of other debts;

(8) to covenant as to the payment of the principal of or interest on the bonds or notes, as to the sources and methods of the payment, as to the rank or priority of the bonds or notes with respect to a lien or security, or as to the acceleration of the maturity of the bonds or notes;

(9) to provide for the replacement of lost, stolen, destroyed or mutilated bonds or notes;

(10) to covenant against extending the time for the payment of bonds or notes or interest on the bonds or notes;

(11) to covenant as to the redemption of bonds or notes and privileges of their exchange for other bonds or notes of the corporation;

(12) to covenant to create or authorize the creation of special funds of money to be held in pledge or otherwise for operating expenses, payment or redemption of bonds or notes, reserves or other purposes, and as to the use and disposition of the money held in the funds;

(13) to establish the procedure, if any, by which the terms of any contract or covenant with or for the benefit of the holders of bonds or notes may be amended or abrogated, the amount of bonds or notes the holders of which must consent to amendment or abrogation, and the manner in which the consent may be given;

(14) to covenant as to the custody of any of its properties or investments, their safekeeping and insurance, and the use and disposition of insurance money;

(15) to covenant as to the time or manner of enforcement or restraint from enforcement of any rights of the corporation arising by reason of or with respect to nonpayment of any principal or interest of any mortgage loans or construction loans;

(16) to provide for the rights and liabilities, powers and duties arising upon the breach of any covenant, condition or obligation, and to prescribe the events of default and the terms and conditions upon which any or all the bonds, notes or other obligations of the corporation become or may be declared due and payable before maturity and the terms and conditions upon which any such declaration and its consequences may be waived;

(17) to vest in a trustee or trustees within or outside the state such property, rights, powers and duties in trust as the corporation may determine, which may include any or all of the rights, powers and duties of any trustee appointed by the holders of any bonds or notes, and to limit or abrogate the right of the holders of any bonds or notes of the corporation to appoint a trustee under this chapter or limit the rights, powers and duties of the trustee;

(18) to pay the costs or expenses incident to the enforcement of the bonds or notes or of the provisions of the resolution or of any covenant or agreement of the corporation with the holders of its bonds or notes;

(19) to agree with any corporate trustee which may be any trust company or bank having the powers of a trust company within or

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outside the state as to the pledging or assigning of revenues or funds to which or in which the corporation has any rights or interest; the agreement may further provide for such other rights and remedies exercisable by the trustee as may be proper for the protection of the holders of any bonds or notes of the corporation and not otherwise in violation of law and may provide for the restriction of the rights of an individual holder of bonds or notes of the corporation;

(20) to appoint and provide for the duties and obligations of any paying agent or paying agents, or such other fiduciaries as the resolution may provide within or outside the state;

(21) to limit the rights of the holders of any bonds or notes to enforce any pledge or covenant securing bonds or notes;

(22) to make covenants other than and in addition to the covenants expressly authorized in this section, of like or different character, and to make such covenants to do or refrain from doing such acts and things as may be necessary, or convenient and desirable, in order to better secure bonds or notes or which, in the absolute discretion of the corporation, will tend to make bonds or notes more marketable, notwithstanding that the covenants, acts or things may not be enumerated in this section. (§ 1 ch 107 SLA 1971)

Sec. 18.56.115. Prohibited bidding on bonds and notes. (a) No person who provides fiscal programming or marketing assistance to the corporation in connection with the issuance or sale of the corporation's bonds or bond anticipation notes may bid or negotiate on the bonds or notes.

(b) The sale of bonds or notes of the corporation to a person who is prohibited from bidding on the bonds or notes under (a) of this section is against public policy and the sale is void.

(c) In this section, "person" means an individual, firm, agent, factor, intermediary, partnership, corporation, association, bond house, stockbroker or bond broker. (§ 4 ch 102 SLA 1974)

Sec. 18.56.120. Validity of any pledge. The pledge of assets or revenues of the corporation to the payment of the principal or interest on any obligations of the agency is valid and binding from the time the pledge is made and any such assets or revenues are immediately subject to the lien of the pledge without physical delivery or further act. The lien of any pledge is valid and binding against all parties having claims of any kind in tort, contract or otherwise against the corporation, irrespective of whether those parties have notice of the lien of the pledge. Nothing herein prohibits the corporation from selling assets subject to any pledge, except that any sale may be restricted by the trust agreement or resolution providing for the issuance of the obligations. (§ 1 ch 107 SLA 1971)

Sec. 18.56.130. Remedies. A holder of obligations or coupons attached to them issued under the provisions of this chapter, and a

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trustee under any trust agreement or resolution authorizing the issuance of the obligations, except as restricted by a trust agreement or resolution, either at law or in equity, may enforce all rights granted hereunder or under the trust agreement or resolution, or under any other contract executed by the corporation under this chapter, and may enforce and compel the performance of all duties required by this chapter or by the trust agreement or resolution to be performed by the corporation or by any officer of it. (§ 1 ch 107 SLA 1971)

Sec. 18.56.140. Negotiable instruments. All obligations and interest coupons attached to them are negotiable instruments under the laws of this state, subject only to any applicable provisions for registration. (§ 1 ch 107 SLA 1971)

Sec. 18.56.150. Obligations eligible for investment. Obligations issued under the provisions of this chapter are securities in which all public officers and public bodies of the state and its political subdivisions, all insurance companies, trust companies, banking associations, investment companies, executors, administrators, trustees and other fiduciaries may properly and legally invest funds, including capital in their control or belonging to them. These obligations may be deposited with any state or municipal officer of any agency or political subdivision of the state for any purpose for which the deposit of bonds, notes or obligations of the state is authorized by law. (§ 1 ch 107 SLA 1971)

Sec. 18.56.160. Refunding obligations. (a) The corporation may provide for the issuance of refunding obligations for the purpose of refunding any obligations then outstanding which have been issued under the provisions of this chapter, including the payment of any redemption premium on them and any interest accrued or to accrue to the date of redemption of the obligations. The issuance of the obligations, the maturities and other details of them, the rights of the holders of them, and the rights, duties and obligations of the corporation in respect of them are governed by the provisions of this chapter which relate to the issuance of obligations, insofar as those provisions may be appropriate therefor.

(b) Refunding obligations may be sold or exchanged for outstanding obligations issued under this chapter and, if sold, the proceeds may be applied, in addition to any other authorized purposes, to the purchase, redemption or payment of the outstanding obligations. Pending the application of the proceeds of any such refunding obligations, with any other available funds, to the payment of the principal, accrued interest and any redemption premium on the obligations being refunded, and, if so provided or permitted in the resolution authorizing the issuance of the refunding obligations or in the trust agreement securing them, to the payment of any interest on the refunding obligations and any expenses in connection with the refunding, the proceeds may be invested in direct obligations of, or obligations the principal of and the

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interest on which are unconditionally guaranteed by, the United States of America which mature or which will be subject to redemption, at the option of the holders of them, not later than the respective dates when the proceeds, together with the interest accruing on them, will be required for the purposes intended. (§ 1 ch 107 SLA 1971)

Sec. 18.56.170. Credit of state not pledged. (a) Obligations issued under the provisions of this chapter do not constitute a debt, liability or obligation of the state or of any political subdivision of the state or a pledge of the faith and credit of the state or of any such political subdivision but are payable solely from the revenues or assets of the corporation. Each obligation issued under this chapter shall contain on its face a statement that the corporation is not obligated to pay it nor the interest on it except from the revenues or assets pledged for it and that neither the faith and credit nor the taxing power of the state or of any political subdivision of the state is pledged to the payment of the principal of or the interest on the obligation.

(b) Expenses incurred by the corporation in carrying out the provisions of this chapter are payable from funds provided under this chapter and no liability may be incurred by the corporation in excess of these funds. (§ 1 ch 107 SLA 1971)

Sec. 18.56.180. Officers not liable. No member or other officer of the corporation is subject to personal liability or accountability by reason of his execution of any obligations or the issuance of them. (§ 1 ch 107 SLA 1971)

Sec. 18.56.190. Tax exemption. (a) The exercise of the powers granted by this chapter will be in all respects for the benefit of the people of the state, for their well-being and prosperity and for the improvement of their social and economic conditions, and the corporation is not required to pay a tax or assessment on any property owned by the corporation under the provisions of this chapter or upon the income from it, except taxes on real property of which the corporation is fee owner.

(b) All obligations issued under this chapter are hereby declared to be issued by a body corporate and public of the state and for an essential public and governmental purpose, and the obligations, and the interest and income on and from the obligations, and all fees, charges, funds, revenues, income and other money pledged or available to pay or secure the payment of the obligations, or interest on the obligations, are exempt from taxation except for transfer, inheritance and estate taxes. (§ 1 ch 107 SLA 1971)

Sec. 18.56.200. Annual report. The corporation shall prepare and transmit annually a report accounting to the governor and the legislature for the efficient discharge of all responsibility assigned by law or by directive to the corporation. (§ 1 ch 107 SLA 1971)

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Sec. 18.56.210. Definitions. In this chapter, unless the context clearly indicates a different meaning

(1) "corporation" means the Alaska Housing Finance Corporation created by this chapter;

(2) "board" means the board of directors of the corporation;

(3) "development costs" means the costs approved by the corporation as appropriate expenditures which may be incurred by sponsors, builders and developers of residential housing, before commitment and initial advance of the proceeds of a construction loan or of a mortgage loan, including but not limited to

(A) payments for options to purchase properties on the proposed residential housing site, deposits on contracts of purchase, or, with prior approval of the corporation, payments for the purchase of the properties;

(B) legal and organizational expenses, including payments of attorney fees, project manager, clerical and other staff salaries, office rent and other incidental expenses;

(C) payment of fees for preliminary feasibility studies and advances for planning, engineering and architectural work;

(D) expenses for tenant surveys and market analyses; and

(E) necessary application and other fees;

(4) "governmental agency" means any department, division, public agency, political subdivision or other public instrumentality of the state or the federal government;

(5) "housing development fund" means the housing development fund created by § 100 of this chapter;

(6) "construction loan" means a construction loan for land development or residential housing which is secured by a federally insured or guaranteed mortgage or which is insured or guaranteed by the United States or an instrumentality thereof, or for which there is a commitment by the United States or an instrumentality thereof to insure or guarantee such a loan, or a construction loan for land development or residential housing wich land development or residential housing will be secured by a mortgage loan;

(7) "mortgage" or "mortgage loan" means a mortgage loan for residential housing insured or guaranteed by the United States or an instrumentality thereof or for which there is a commitment by the United States or an instrumentality thereof to insure or guarantee such a mortgage, or if not so insured or guaranteed or if there is no such commitment, which the corporation determines meets the conditions described in § 100(k) of this chapter or which shall be secured upon such terms and conditions as the corporation considers necessary or practicable to insure all repayments;

(8) "land development" means the process of acquiring land primarily for residential housing construction for persons of lower and moderate income and making, installing or constructing nonresidential housing improvements, including water, sewer and other utilities,

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roads, streets, curbs, gutters, sidewalks, storm drainage facilities and other installations or works, whether on or off the site, which the corporation considers necessary or desirable to prepare the land primarily for residential housing construction;

(9) "obligations" means any bonds, bond anticipation notes or fund notes authorized to be issued by the agency under the provisions of this chapter;

(10) "persons of lower and moderate income" means a person or persons considered by the corporation to require assistance available under this chapter on account of insufficient or inadequate personal or family income or otherwise limited personal financial resources, taking into consideration, without limitation, such factors as

(A) the amount of the total income of the persons available for housing needs;

(B) the size of the family;

(C) the cost and condition of housing facilities available;

(D) standards established for various federal programs determining eligibility based on income of the persons; and

(E) the ability of the persons to compete successfully in the normal housing market and to pay the amounts at which private enterprise is providing decent, safe and sanitary housing;

(11) "residential housing" means a specific work or improvement undertaken primarily to provide dwelling accommodations without limitation as to form of lawful occupancy, whether rental, under contract, fee ownership, cooperative housing, condominium or other lawful forms of ownership, for persons of lower and moderate income, or in remote, underdeveloped or blighted areas, including the acquisition, construction or rehabilitation of land, buildings and improvements thereto, and such other nonhousing facilities as may be incidental or appurtenant thereto;

(12) "remote, underdeveloped or blighted areas" means areas considered by the corporation to require assistance available under this chapter on account of insufficient availability of the residential housing necessary to promote, develop or maintain the economic growth or potential of the area, taking into consideration, without limitation, the following:

(A) the population, resources and environment of the area;

(B) the present availability and condition of residential housing in and near the area;

(C) the cost of construction and rehabilitation of residential housing in the area;

(D) the availability of other federal or state sponsored progams to facilitate the development of residential housing in the area; and

(E) the ability of residents of the area to finance the purchase of residential housing or to rent or lease such housing at rates comparable

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to those in effect in other areas of the state. (§ 1 ch 107 SLA 1971; am §§ 5 — 10 ch 81 SLA 1972)

Effect of amendment. — The 1972 amendment inserted "loan" following "mortgage" in the introductory language of paragraph (3); substituted "or which shall be secured upon such term/s and conditions as the corporation considers necessary or practicable to insure all repayments" for "for a loan from the housing development fund" in paragraph (7); inserted "and moderate" in paragraph (8); inserted "and moderate," "a person or," "or inadequate," and "or otherwise limited personal financial resources" in the introductory language of paragraph (10); inserted "and moderate" and "or in remote, underdeveloped or blighted areas" in paragraph (11); and added paragraph (12).

Legislative committee report. — For report on ch. 81, SLA 1972 (CSHB 547), see 1972 House Journal, p. 859.

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APPENDIX
STATE OF ALASKA
Feasibility Study of
Pipeline Transportation
Royalty Gas and NGL

Prepared for

THE STATE OF ALASKA
and BONNER & MOORE ASSOCIATES, INC.

January 1978

Prepared by
PIPE LINE TECHNOLOGISTS, INC.
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APPENDIX

CASE I

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IA1 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	182600	182600	182600	182600	182600	182600	182600
COST OF SERVICE ($/BBL)	.467	.467	.467	.467	.467	.467	.467	.467	.467
TOTAL REVENUE	0	0	31103859	31103859	31103859	31103859	31103859	31103859	31103859
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	16700000	16700000	16700000	16700000	16700000	16700000	16700000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	17832500	17832500	17832500	17832500	17832500	17832500	17832500
TOTAL EXPENSES	0	0	34532500	34532500	34532500	34532500	34532500	34532500	34532500
INCOME BEFORE TAXES	0	0	-3428641	-3428641	-3428641	-3428641	-3428641	-3428641	-3428641
INVESTMENT TAX CREDIT	0	0	35665000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	35665000	32098500	28888650	25999785	23399807	21059826	18953843
TAXABLE INCOME	0	0	-21261141	-17694641	-14484791	-11595926	-8995948	-6655967	-4549984
CURRENT INCOME TAX	0	0	-45870348	-8493428	-6952700	-5566045	-4318055	-3194864	-2183992
DEFERRED INCOME TAX	0	0	8559600	6847680	5306952	3920297	2672307	1549116	538244
TOTAL INCOME TAXES	0	0	-37310748	-1645748	-1645748	-1645748	-1645748	-1645748	-1645748
NET INCOME (BOOK)	0	0	33882107	-1782893	-1782893	-1782893	-1782893	-1782893	-1782893
SOURCES OF FUNDS									
NET INCOME	0	0	33882107	-1782893	-1782893	-1782893	-1782893	-1782893	-1782893
FINANCIAL DEPRECIATION	0	0	17832500	17832500	17832500	17832500	17832500	17832500	17832500
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	8559600	6847680	5306952	3920297	2672307	1549116	538244
NET ADDITIONS TO EQUITY	178325000	178325000	0	0	0	0	0	0	0
TOTAL SOURCES	178325000	178325000	60274207	22897287	21356559	19969904	18721914	17598723	16587851
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	178325000	178325000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	178325000	178325000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	60274207	22897287	21356559	19969904	18721914	17598723	16587851
CUMULATIVE NET CASH GENERATED	0	0	60274207	83171494	104528053	124497957	143219871	160818594	177406445
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

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EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IA1 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	182600	182600	182600	182600	182600	182600	182600	182600	182600
COST OF SERVICE ($/BBL)	.467	.467	.467	.467	.467	.467	.467	.467	.467
TOTAL REVENUE	31103859	31103859	31103859	31103859	31103859	31103859	31103859	31103859	31103859
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	16700000	16700000	16700000	16700000	16700000	16700000	16700000	16700000	16700000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	17832500	17832500	17832500	17832500	17832500	17832500	17832500	17832500	17832500
TOTAL EXPENSES	34532500	34532500	34532500	34532500	34532500	34532500	34532500	34532500	34532500
INCOME BEFORE TAXES	-3428641	-3428641	-3428641	-3428641	-3428641	-3428641	-3428641	-3428641	-3428641
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	17058459	15352513	13817352	12435617	12435617	12435617	12435617	12435617	12435617
TAXABLE INCOME	-2654600	-948754	586507	1968242	1968242	1968242	1968242	1968242	1968242
CURRENT INCOME TAX	-1274208	-455402	281523	944756	944756	944756	944756	944756	944756
DEFERRED INCOME TAX	-371540	-1190346	-1927271	-2590504	-2590504	-2590504	-2590504	-2590504	-2590504
TOTAL INCOME TAXES	-1645748	-1645748	-1645748	-1645748	-1645748	-1645748	-1645748	-1645748	-1645748
NET INCOME (BOOK)	-1782893	-1782893	-1782893	-1782893	-1782893	-1782893	-1782893	-1782893	-1782893
SOURCES OF FUNDS									
NET INCOME	-1782893	-1782893	-1782893	-1782893	-1782893	-1782893	-1782893	-1782893	-1782893
FINANCIAL DEPRECIATION	17832500	17832500	17832500	17832500	17832500	17832500	17832500	17832500	17832500
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-371540	-1190346	-1927271	-2590504	-2590504	-2590504	-2590504	-2590504	-2590504
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	15678067	14859261	14122336	13459103	13459103	13459103	13459103	13459103	13459103
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	15678067	14859261	14122336	13459103	13459103	13459103	13459103	13459103	13459103
CUMULATIVE NET CASH GENERATED	193084512	207943773	222066109	235525212	248984315	262443418	275902521	289361624	30.820727
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

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EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IA1 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	182600	182600	182600	182600	3652000	182600
COST OF SERVICE ($/BBL)	.467	.467	.467	.467	10.274	.514
TOTAL REVENUE	31103859	31103859	31103859	31103859	622077180	31103859
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	16700000	16700000	16700000	16700000	334000000	16700000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	17832500	17832500	17832500	17832500	356650000	17832500
TOTAL EXPENSES	34532500	34532500	34532500	34532500	690650000	34532500
INCOME BEFORE TAXES	-3428641	-3428641	-3428641	-3428641	-68572820	-3428641
INVESTMENT TAX CREDIT	0	0	0	0	35665000	1783250
TAX DEPRECIATION	12435617	12435617	12435617	12435617	356650005	17832500
TAXABLE INCOME	1968242	1968242	1968242	1968242	-68572825	-3428641
CURRENT INCOME TAX	944756	944756	944756	944756	-68579959	-3428998
DEFERRED INCOME TAX	-2590504	-2590504	-2590504	-2590504	-1	0
TOTAL INCOME TAXES	-1645748	-1645748	-1645748	-1645748	-68579960	-3428998
NET INCOME (BOOK)	-1782893	-1782893	-1782893	-1782893	7140	357
SOURCES OF FUNDS						
NET INCOME	-1782893	-1782893	-1782893	-1782893	7140	357
FINANCIAL DEPRECIATION	17832500	17832500	17832500	17832500	356650000	17832500
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2590504	-2590504	-2590504	-2590504	-1	0
NET ADDITIONS TO EQUITY	0	0	0	0	356650000	17832500
TOTAL SOURCES	13459103	13459103	13459103	13459103	713307139	35665357
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	356650000	17832500
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	356650000	17832500
NET CASH GENERATED DURING YEAR	13459103	13459103	13459103	13459103	356657139	17832857
CUMULATIVE NET CASH GENERATED	316279830	329738933	343198036	356657139	43722770	321896139
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

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EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 181 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO HAINES

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	182600	182600	182600	182600	182600	182600	182600
COST OF SERVICE ($/BBL)	1.121	1.121	1.121	1.121	1.121	1.121	1.121	1.121	1.121
TOTAL REVENUE	0	0	74737234	74737234	74737234	74737234	74737234	74737234	74737234
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	39615000	39615000	39615000	39615000	39615000	39615000	39615000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	43482600	43482600	43482600	43482600	43482600	43482600	43482600
TOTAL EXPENSES	0	0	83097600	83097600	83097600	83097600	83097600	83097600	83097600
INCOME BEFORE TAXES	0	0	-8360366	-8360366	-8360366	-8360366	-8360366	-8360366	-8360366
INVESTMENT TAX CREDIT	0	0	86965200	0	0	0	0	0	0
TAX DEPRECIATION	0	0	86965200	78268680	70441812	63397631	57057868	51352081	44216873
TAXABLE INCOME	0	0	-51842966	-43146446	-35319578	-28275397	-21935634	-16229847	-11094639
CURRENT INCOME TAX	0	0	-111849824	-20710294	-16953397	-13572190	-10529104	-7790327	-5325427
DEFERRED INCOME TAX	0	0	20871648	16697318	12940421	9559214	6516128	3777351	1312451
TOTAL INCOME TAXES	0	0	-90978176	-4012976	-4012976	-4012976	-4012976	-4012976	-4012976
NET INCOME (BOOK)	0	0	82617810	-4347390	-4347390	-4347390	-4347390	-4347390	-4347390
SOURCES OF FUNDS									
NET INCOME	0	0	82617810	-4347390	-4347390	-4347390	-4347390	-4347390	-4347390
FINANCIAL DEPRECIATION	0	0	43482600	43482600	43482600	43482600	43482600	43482600	43482600
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	20871648	16697318	12940421	9559214	6516128	3777351	1312451
NET ADDITIONS TO EQUITY	434826000	434826000	0	0	0	0	0	0	0
TOTAL SOURCES	434826000	434826000	146972058	55832528	52075631	48694424	45651338	42912561	40447661
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	434826000	434826000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	434826000	434826000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	146972058	55832528	52075631	48694424	45651338	42912561	40447661
CUMULATIVE NET CASH GENERATED	0	0	146972058	202804586	254880217	303574641	349225979	392138540	432586201
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545109

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 1B1 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO HAINES

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	182600	182600	182600	182600	182600	182600	182600	182600	182600
COST OF SERVICE ($/BBL)	1.121	1.121	1.121	1.121	1.121	1.121	1.121	1.121	1.121
TOTAL REVENUE	74737234	74737234	74737234	74737234	74737234	74737234	74737234	74737234	74737234
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	39615000	39615000	39615000	39615000	39615000	39615000	39615000	39615000	39615000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	43482600	43482600	43482600	43482600	43482600	43482600	43482600	43482600	43482600
TOTAL EXPENSES	83097600	83097600	83097600	83097600	83097600	83097600	83097600	83097600	83097600
INCOME BEFORE TAXES	-8360366	-8360366	-8360366	-8360366	-8360366	-8360366	-8360366	-8360366	-8360366
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	41595186	37435657	33692100	30322890	30322890	30322890	30322890	30322890	30322890
TAXABLE INCOME	-6472952	-2313433	1430134	4799344	4799344	4799344	4799344	4799344	4799344
CURRENT INCOME TAX	-3107017	-1110448	686464	2303685	2303685	2303685	2303685	2303685	2303685
DEFERRED INCOME TAX	-905959	-2902528	-4699440	-6316661	-6316661	-6316661	-6316661	-6316661	-6316661
TOTAL INCOME TAXES	-4012976	-4012976	-4012976	-4012976	-4012976	-4012976	-4012976	-4012976	-4012976
NET INCOME (BOOK)	-4347390	-4347390	-4347390	-4347390	-4347390	-4347390	-4347390	-4347390	-4347390
SOURCES OF FUNDS									
NET INCOME	-4347390	-4347390	-4347390	-4347390	-4347390	-4347390	-4347390	-4347390	-4347390
FINANCIAL DEPRECIATION	43482600	43482600	43482600	43482600	43482600	43482600	43482600	43482600	43482600
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-905959	-2902528	-4699440	-6316661	-6316661	-6316661	-6316661	-6316661	-6316661
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	38229251	36232682	34435770	32818549	32818549	32818549	32818549	32818549	32818549
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	38229251	36232682	34435770	32818549	32818549	32818549	32818549	32818549	32818549
CUMULATIVE NET CASH GENERATED	470815452	507048134	541483904	574302453	607121002	639939551	672758100	705576649	738395198
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545110

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IB1 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO HAINES

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	182600	182600	182600	182600	3652000	182600
COST OF SERVICE ($/BBL)	1.121	1.121	1.121	1.121	24.662	1.233
TOTAL REVENUE	74737234	74737234	74737234	74737234	1494744680	74737234
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	39615000	39615000	39615000	39615000	792300000	39615000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	43482600	43482600	43482600	43482600	869652000	43482600
TOTAL EXPENSES	83097600	83097600	83097600	83097600	1661952000	83097600
INCOME BEFORE TAXES	-8360366	-8360366	-8360366	-8360366	-167207320	-8360366
INVESTMENT TAX CREDIT	0	0	0	0	86965200	4348260
TAX DEPRECIATION	30322890	30322890	30322890	30322890	869651998	43482600
TAXABLE INCOME	4799344	4799344	4799344	4799344	-167207318	-8360366
CURRENT INCOME TAX	2303685	2303685	2303685	2303685	-167224714	-8361236
DEFERRED INCOME TAX	-6316661	-6316661	-6316661	-6316661	-6	0
TOTAL INCOME TAXES	-4012976	-4012976	-4012976	-4012976	-167224720	-8361236
NET INCOME (BOOK)	-4347390	-4347390	-4347390	-4347390	17400	870
SOURCES OF FUNDS						
NET INCOME	-4347390	-4347390	-4347390	-4347390	17400	870
FINANCIAL DEPRECIATION	43482600	43482600	43482600	43482600	869652000	43482600
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-6316661	-6316661	-6316661	-6316661	-6	0
NET ADDITIONS TO EQUITY	0	0	0	0	869652000	43482600
TOTAL SOURCES	32818549	32818549	32818549	32818549	1739321394	86966070
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	869652000	43482600
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	869652000	43482600
NET CASH GENERATED DURING YEAR	32818549	32818549	32818549	32818549	869669394	43483470
CUMULATIVE NET CASH GENERATED	771213747	804032296	836850845	869669394	**********	541069447
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545111

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IC1 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO KENAI

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	182600	182600	182600	182600	182600	182600	182600
COST OF SERVICE ($/BBL)	.922	.922	.922	.922	.922	.922	.922	.922	.922
TOTAL REVENUE	0	0	61427624	61427624	61427624	61427624	61427624	61427624	61427624
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	32730000	32730000	32730000	32730000	32730000	32730000	32730000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	35528700	35528700	35528700	35528700	35528700	35528700	35528700
TOTAL EXPENSES	0	0	68258700	68258700	68258700	68258700	68258700	68258700	68258700
INCOME BEFORE TAXES	0	0	-6831076	-6831076	-6831076	-6831076	-6831076	-6831076	-6831076
INVESTMENT TAX CREDIT	0	0	71057400	0	0	0	0	0	0
TAX DEPRECIATION	0	0	71057400	63951660	57556494	51800845	46620760	41958684	37762816
TAXABLE INCOME	0	0	-42359776	-35254036	-28858870	-23103221	-17923136	-13261060	-9065192
CURRENT INCOME TAX	0	0	-91390092	-16921937	-13852258	-11089546	-8603105	-6365309	-4351292
DEFERRED INCOME TAX	0	0	17053776	13643021	10573342	7810630	5324189	3086393	1072376
TOTAL INCOME TAXES	0	0	-74336316	-3278916	-3278916	-3278916	-3278916	-3278916	-3278916
NET INCOME (BOOK)	0	0	67505240	-3552160	-3552160	-3552160	-3552160	-3552160	-3552160
SOURCES OF FUNDS									
NET INCOME	0	0	67505240	-3552160	-3552160	-3552160	-3552160	-3552160	-3552160
FINANCIAL DEPRECIATION	0	0	35528700	35528700	35528700	35528700	35528700	35528700	35528700
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	17053776	13643021	10573342	7810630	5324189	3086393	1072376
NET ADDITIONS TO EQUITY	355287000	355287000	0	0	0	0	0	0	0
TOTAL SOURCES	355287000	355287000	120087716	45619561	42549882	39787170	37300729	35062933	33048916
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	355287000	355287000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	355287000	355287000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	120087716	45619561	42549882	39787170	37300729	35062933	33048916
CUMULATIVE NET CASH GENERATED	0	0	120087716	165707277	208257159	248044329	285345058	320407991	353456907
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545112

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 1C1 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO KENAI

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	182600	182600	182600	182600	182600	182600	182600	182600	182600
COST OF SERVICE ($/BBL)	.922	.922	.922	.922	.922	.922	.922	.922	.922
TOTAL REVENUE	61427624	61427624	61427624	61427624	61427624	61427624	61427624	61427624	61427624
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	32730000	32730000	32730000	32730000	32730000	32730000	32730000	32730000	32730000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	35528700	35528700	35528700	35528700	35528700	35528700	35528700	35528700	35528700
TOTAL EXPENSES	68258700	68258700	68258700	68258700	68258700	68258700	68258700	68258700	68258700
INCOME BEFORE TAXES	-6831076	-6831076	-6831076	-6831076	-6831076	-6831076	-6831076	-6831076	-6831076
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	33986534	30587881	27529093	24776183	24776183	24776183	24776183	24776183	24776183
TAXABLE INCOME	-5288910	-1890257	1168531	3921441	3921441	3921441	3921441	3921441	3921441
CURRENT INCOME TAX	-2538677	-907323	560895	1882292	1882292	1882292	1882292	1882292	1882292
DEFERRED INCOME TAX	-740239	-2371593	-3839811	-5161208	-5161208	-5161208	-5161208	-5161208	-5161208
TOTAL INCOME TAXES	-3278916	-3278916	-3278916	-3278916	-3278916	-3278916	-3278916	-3278916	-3278916
NET INCOME (BOOK)	-3552160	-3552160	-3552160	-3552160	-3552160	-3552160	-3552160	-3552160	-3552160
SOURCES OF FUNDS									
NET INCOME	-3552160	-3552160	-3552160	-3552160	-3552160	-3552160	-3552160	-3552160	-3552160
FINANCIAL DEPRECIATION	35528700	35528700	35528700	35528700	35528700	35528700	35528700	35528700	35528700
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-740239	-2371593	-3839811	-5161208	-5161208	-5161208	-5161208	-5161208	-5161208
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	31236301	29604947	28136729	26815332	26815332	26815332	26815332	26815332	26815332
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	31236301	29604947	28136729	26815332	26815332	26815332	26815332	26815332	26815332
CUMULATIVE NET CASH GENERATED	384693208	414298155	442434884	469250216	496065548	522880880	549696212	576511544	603326876
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545113

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IC1 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO KENAI

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	182600	182600	182600	182600	3652000	182600
COST OF SERVICE ($/BBL)	.922	.922	.922	.922	20.284	1.014
TOTAL REVENUE	61427624	61427624	61427624	61427624	1228552480	61427624
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	32730000	32730000	32730000	32730000	654600000	32730000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	35528700	35528700	35528700	35528700	710574000	35528700
TOTAL EXPENSES	68258700	68258700	68258700	68258700	1365174000	68258700
INCOME BEFORE TAXES	-6831076	-6831076	-6831076	-6831076	-136621520	-6831076
INVESTMENT TAX CREDIT	0	0	0	0	71057400	3552870
TAX DEPRECIATION	24776183	24776183	24776183	24776183	710573997	35528700
TAXABLE INCOME	3921441	3921441	3921441	3921441	-136621517	-6831076
CURRENT INCOME TAX	1882292	1882292	1882292	1882292	-136635724	-6831786
DEFERRED INCOME TAX	-5161208	-5161208	-5161208	-5161208	4	0
TOTAL INCOME TAXES	-3278916	-3278916	-3278916	-3278916	-136635720	-6831786
NET INCOME (BOOK)	-3552160	-3552160	-3552160	-3552160	14200	710
SOURCES OF FUNDS						
NET INCOME	-3552160	-3552160	-3552160	-3552160	14200	710
FINANCIAL DEPRECIATION	35528700	35528700	35528700	35528700	710574000	35528700
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-5161208	-5161208	-5161208	-5161208	4	0
NET ADDITIONS TO EQUITY	0	0	0	0	710574000	35528700
TOTAL SOURCES	26815332	26815332	26815332	26815332	1421162204	71058110
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	710574000	35528700
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	710574000	35528700
NET CASH GENERATED DURING YEAR	26815332	26815332	26815332	26815332	710588204	35529410
CUMULATIVE NET CASH GENERATED	630142208	656957540	683772872	710588204	1841924784	442096239
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545114

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IA2 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	.861	.861	.861	.861	.861	.861	.861	.861	.861
TOTAL REVENUE	0	0	22241461	22241461	22241461	22241461	22241461	22241461	22241461
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	13120000	13120000	13120000	13120000	13120000	13120000	13120000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	11292700	11292700	11292700	11292700	11292700	11292700	11292700
TOTAL EXPENSES	0	0	24412700	24412700	24412700	24412700	24412700	24412700	24412700
INCOME BEFORE TAXES	0	0	-2171239	-2171239	-2171239	-2171239	-2171239	-2171239	-2171239
INVESTMENT TAX CREDIT	0	0	22585400	0	0	0	0	0	0
TAX DEPRECIATION	0	0	22585400	20326860	18294174	16464757	14818281	13336453	12002808
TAXABLE INCOME	0	0	-13463939	-11205399	-9172713	-7343296	-5696820	-4214992	-2881347
CURRENT INCOME TAX	0	0	-29048091	-5378591	-4402902	-3524782	-2734473	-2023196	-1383046
DEFERRED INCOME TAX	0	0	5420496	4336396	3360707	2482587	1692278	981001	340851
TOTAL INCOME TAXES	0	0	-23627595	-1042195	-1042195	-1042195	-1042195	-1042195	-1042195
NET INCOME (BOOK)	0	0	21456356	-1129044	-1129044	-1129044	-1129044	-1129044	-1129044
SOURCES OF FUNDS									
NET INCOME	0	0	21456356	-1129044	-1129044	-1129044	-1129044	-1129044	-1129044
FINANCIAL DEPRECIATION	0	0	11292700	11292700	11292700	11292700	11292700	11292700	11292700
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	5420496	4336396	3360707	2482587	1692278	981001	340851
NET ADDITIONS TO EQUITY	112927000	112927000	0	0	0	0	0	0	0
TOTAL SOURCES	112927000	112927000	38169552	14500052	13524363	12646243	11855934	11144657	10504507
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	112927000	112927000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	112927000	112927000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	38169552	14500052	13524363	12646243	11855934	11144657	10504507
CUMULATIVE NET CASH GENERATED	0	0	38169552	52669604	66193967	78840210	90696144	101840801	112345308
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545115

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IA2 PROCESS B/B GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	70800	70800	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	.861	.861	.861	.861	.861	.861	.861	.861	.861
TOTAL REVENUE	22241461	22241461	22241461	22241461	22241461	22241461	22241461	22241461	22241461
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	13120000	13120000	13120000	13120000	13120000	13120000	13120000	13120000	13120000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	11292700	11292700	11292700	11292700	11292700	11292700	11292700	11292700	11292700
TOTAL EXPENSES	24412700	24412700	24412700	24412700	24412700	24412700	24412700	24412700	24412700
INCOME BEFORE TAXES	-2171239	-2171239	-2171239	-2171239	-2171239	-2171239	-2171239	-2171239	-2171239
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	10802527	9722274	8750047	7875042	7875042	7875042	7875042	7875042	7875042
TAXABLE INCOME	-1681066	-600813	371414	1246419	1246419	1246419	1246419	1246419	1246419
CURRENT INCOME TAX	-806911	-289390	178279	598281	598281	598281	598281	598281	598281
DEFERRED INCOME TAX	-235284	-753805	-1220474	-1640476	-1640476	-1640476	-1640476	-1640476	-1640476
TOTAL INCOME TAXES	-1042195	-1042195	-1042195	-1042195	-1042195	-1042195	-1042195	-1042195	-1042195
NET INCOME (BOOK)	-1129044	-1129044	-1129044	-1129044	-1129044	-1129044	-1129044	-1129044	-1129044
SOURCES OF FUNDS									
NET INCOME	-1129044	-1129044	-1129044	-1129044	-1129044	-1129044	-1129044	-1129044	-1129044
FINANCIAL DEPRECIATION	11292700	11292700	11292700	11292700	11292700	11292700	11292700	11292700	11292700
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-235284	-753805	-1220474	-1640476	-1640476	-1640476	-1640476	-1640476	-1640476
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	9928372	9409851	8943182	8523180	8523180	8523180	8523180	8523180	8523180
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	9928372	9409851	8943182	8523180	8523180	8523180	8523180	8523180	8523180
CUMULATIVE NET CASH GENERATED	122273680	131683531	140626713	149149893	157673073	166196253	174719433	183242613	191765793
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545116

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 1A2 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	70800	70800	70800	70800	1416000	70800
COST OF SERVICE ($/BBL)	.861	.861	.861	.861	18.942	.947
TOTAL REVENUE	22241461	22241461	22241461	22241461	444829220	22241461
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	13120000	13120000	13120000	13120000	262400000	13120000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	11292700	11292700	11292700	11292700	225854000	11292700
TOTAL EXPENSES	24412700	24412700	24412700	24412700	488254000	24412700
INCOME BEFORE TAXES	-2171239	-2171239	-2171239	-2171239	-43424780	-2171239
INVESTMENT TAX CREDIT	0	0	0	0	22585400	1129270
TAX DEPRECIATION	7875042	7875042	7875042	7875042	225854001	11292700
TAXABLE INCOME	1246419	1246419	1246419	1246419	-43424781	-2171239
CURRENT INCOME TAX	598281	598281	598281	598281	-43429293	-2171465
DEFERRED INCOME TAX	-1640476	-1640476	-1640476	-1640476	-7	0
TOTAL INCOME TAXES	-1042195	-1042195	-1042195	-1042195	-43429300	-2171465
NET INCOME (BOOK)	-1129044	-1129044	-1129044	-1129044	4520	226
SOURCES OF FUNDS						
NET INCOME	-1129044	-1129044	-1129044	-1129044	4520	226
FINANCIAL DEPRECIATION	11292700	11292700	11292700	11292700	225854000	11292700
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1640476	-1640476	-1640476	-1640476	-7	0
NET ADDITIONS TO EQUITY	0	0	0	0	225854000	11292700
TOTAL SOURCES	8523180	8523180	8523180	8523180	451712513	22585626
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	225854000	11292700
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	225854000	11292700
NET CASH GENERATED DURING YEAR	8523180	8523180	8523180	8523180	225858513	11292926
CUMULATIVE NET CASH GENERATED	200288973	208812153	217335333	225858513	2810381540	140519077
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545117

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IB2 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO HAINES

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	2.050	2.050	2.050	2.050	2.050	2.050	2.050	2.050	2.050
TOTAL REVENUE	0	0	52981175	52981175	52981175	52981175	52981175	52981175	52981175
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	30800000	30800000	30800000	30800000	30800000	30800000	30800000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	27461100	27461100	27461100	27461100	27461100	27461100	27461100
TOTAL EXPENSES	0	0	58261100	58261100	58261100	58261100	58261100	58261100	58261100
INCOME BEFORE TAXES	0	0	-5279925	-5279925	-5279925	-5279925	-5279925	-5279925	-5279925
INVESTMENT TAX CREDIT	0	0	54922200	0	0	0	0	0	0
TAX DEPRECIATION	0	0	54922200	49429980	44486982	40038284	36034455	32431010	29187909
TAXABLE INCOME	0	0	-32741025	-27248805	-22305807	-17857109	-13853280	-10249835	-7006734
CURRENT INCOME TAX	0	0	-70637892	-13079426	-10706787	-8571412	-6649574	-4919921	-3363232
DEFERRED INCOME TAX	0	0	13181328	10545062	8172423	6037048	4115210	2385557	828868
TOTAL INCOME TAXES	0	0	-57456564	-2534364	-2534364	-2534364	-2534364	-2534364	-2534364
NET INCOME (BOOK)	0	0	52176639	-2745561	-2745561	-2745561	-2745561	-2745561	-2745561
SOURCES OF FUNDS									
NET INCOME	0	0	52176639	-2745561	-2745561	-2745561	-2745561	-2745561	-2745561
FINANCIAL DEPRECIATION	0	0	27461100	27461100	27461100	27461100	27461100	27461100	27461100
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	13181328	10545062	8172423	6037048	4115210	2385557	828868
NET ADDITIONS TO EQUITY	274611000	274611000	0	0	0	0	0	0	0
TOTAL SOURCES	274611000	274611000	92819067	35260601	32887962	30752587	28830749	27101096	25544407
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	274611000	274611000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	274611000	274611000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	92819067	35260601	32887962	30752587	28830749	27101096	25544407
CUMULATIVE NET CASH GENERATED	0	0	92819067	128079668	160967630	191720217	220550966	247652062	273196469
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545118

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IB2 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO HAINES

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	70800	70800	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	2.050	2.050	2.050	2.050	2.050	2.050	2.050	2.050	2.050
TOTAL REVENUE	52981175	52981175	52981175	52981175	52981175	52981175	52981175	52981175	52981175
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	30800000	30800000	30800000	30800000	30800000	30800000	30800000	30800000	30800000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	27461100	27461100	27461100	27461100	27461100	27461100	27461100	27461100	27461100
TOTAL EXPENSES	58261100	58261100	58261100	58261100	58261100	58261100	58261100	58261100	58261100
INCOME BEFORE TAXES	-5279925	-5279925	-5279925	-5279925	-5279925	-5279925	-5279925	-5279925	-5279925
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	26269110	23642206	21277986	19150187	19150187	19150187	19150187	19150187	19150187
TAXABLE INCOME	-4087943	-1461031	903189	3030988	3030988	3030988	3030988	3030988	3030988
CURRENT INCOME TAX	-1962212	-701295	433531	1454874	1454874	1454874	1454874	1454874	1454874
DEFERRED INCOME TAX	-572152	-1833069	-2967895	-3989238	-3989238	-3989238	-3989238	-3989238	-3989238
TOTAL INCOME TAXES	-2534364	-2534364	-2534364	-2534364	-2534364	-2534364	-2534364	-2534364	-2534364
NET INCOME (BOOK)	-2745561	-2745561	-2745561	-2745561	-2745561	-2745561	-2745561	-2745561	-2745561
SOURCES OF FUNDS									
NET INCOME	-2745561	-2745561	-2745561	-2745561	-2745561	-2745561	-2745561	-2745561	-2745561
FINANCIAL DEPRECIATION	27461100	27461100	27461100	27461100	27461100	27461100	27461100	27461100	27461100
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-572152	-1833069	-2967895	-3989238	-3989238	-3989238	-3989238	-3989238	-3989238
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	24143387	22882470	21747644	20726301	20726301	20726301	20726301	20726301	20726301
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	24143387	22882470	21747644	20726301	20726301	20726301	20726301	20726301	20726301
CUMULATIVE NET CASH GENERATED	297339856	320222326	341969970	362696271	383422572	404148873	424875174	445601475	466327776
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545119

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IB2 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO HAINES

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	70800	70800	70800	70800	1416000	70800
COST OF SERVICE ($/BBL)	2.050	2.050	2.050	2.050	45.100	2.255
TOTAL REVENUE	52981175	52981175	52981175	52981175	1059623500	52981175
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	30800000	30800000	30800000	30800000	616000000	30800000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	27461100	27461100	27461100	27461100	549222000	27461100
TOTAL EXPENSES	58261100	58261100	58261100	58261100	1165222000	58261100
INCOME BEFORE TAXES	-5279925	-5279925	-5279925	-5279925	-105598500	-5279925
INVESTMENT TAX CREDIT	0	0	0	0	54922200	2746110
TAX DEPRECIATION	19150187	19150187	19150187	19150187	549222000	27461100
TAXABLE INCOME	3030988	3030988	3030988	3030988	-105598500	-5279925
CURRENT INCOME TAX	1454874	1454874	1454874	1454874	-105609480	-5280474
DEFERRED INCOME TAX	-3989238	-3989238	-3989238	-3989238	0	0
TOTAL INCOME TAXES	-2534364	-2534364	-2534364	-2534364	-105609480	-5280474
NET INCOME (BOOK)	-2745561	-2745561	-2745561	-2745561	10980	549
SOURCES OF FUNDS						
NET INCOME	-2745561	-2745561	-2745561	-2745561	10980	549
FINANCIAL DEPRECIATION	27461100	27461100	27461100	27461100	549222000	27461100
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-3989238	-3989238	-3989238	-3989238	0	0
NET ADDITIONS TO EQUITY	0	0	0	0	549222000	27461100
TOTAL SOURCES	20726301	20726301	20726301	20726301	1098454980	54922749
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	549222000	27461100
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	549222000	27461100
NET CASH GENERATED DURING YEAR	20726301	20726301	20726301	20726301	549232980	27461649
CUMULATIVE NET CASH GENERATED	487054077	507780378	528506679	549232980	6834164486	341708224
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545120

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IC2 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO KENAI

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	1.694	1.694	1.694	1.694	1.694	1.694	1.694	1.694	1.694
TOTAL REVENUE	0	0	43767335	43767335	43767335	43767335	43767335	43767335	43767335
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	25590000	25590000	25590000	25590000	25590000	25590000	25590000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	22504200	22504200	22504200	22504200	22504200	22504200	22504200
TOTAL EXPENSES	0	0	48094200	48094200	48094200	48094200	48094200	48094200	48094200
INCOME BEFORE TAXES	0	0	-4326865	-4326865	-4326865	-4326865	-4326865	-4326865	-4326865
INVESTMENT TAX CREDIT	0	0	45008400	0	0	0	0	0	0
TAX DEPRECIATION	0	0	45008400	40507560	36456804	32811124	29530011	26577010	23919309
TAXABLE INCOME	0	0	-26831065	-22330225	-18279469	-14633789	-11352676	-8399675	-5741974
CURRENT INCOME TAX	0	0	-57887311	-10718508	-8774145	-7024219	-5449285	-4031844	-2756148
DEFERRED INCOME TAX	0	0	10802016	8641613	6697250	4947324	3372390	1954949	679253
TOTAL INCOME TAXES	0	0	-47085295	-2076895	-2076895	-2076895	-2076895	-2076895	-2076895
NET INCOME (BOOK)	0	0	42758430	-2249970	-2249970	-2249970	-2249970	-2249970	-2249970
SOURCES OF FUNDS									
NET INCOME	0	0	42758430	-2249970	-2249970	-2249970	-2249970	-2249970	-2249970
FINANCIAL DEPRECIATION	0	0	22504200	22504200	22504200	22504200	22504200	22504200	22504200
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	10802016	8641613	6697250	4947324	3372390	1954949	679253
NET ADDITIONS TO EQUITY	225042000	225042000	0	0	0	0	0	0	0
TOTAL SOURCES	225042000	225042000	76064646	28895843	26951480	25201554	23626620	22209179	20933483
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	225042000	225042000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	225042000	225042000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	76064646	28895843	26951480	25201554	23626620	22209179	20933483
CUMULATIVE NET CASH GENERATED	0	0	76064646	104960489	131911969	157113523	180740143	202949322	223882805
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545121

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IC2 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO KENAI

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	70800	70800	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	1.694	1.694	1.694	1.694	1.694	1.694	1.694	1.694	1.694
TOTAL REVENUE	43767335	43767335	43767335	43767335	43767335	43767335	43767335	43767335	43767335
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	25590000	25590000	25590000	25590000	25590000	25590000	25590000	25590000	25590000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	22504200	22504200	22504200	22504200	22504200	22504200	22504200	22504200	22504200
TOTAL EXPENSES	48094200	48094200	48094200	48094200	48094200	48094200	48094200	48094200	48094200
INCOME BEFORE TAXES	-4326865	-4326865	-4326865	-4326865	-4326865	-4326865	-4326865	-4326865	-4326865
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	21527378	19374640	17437176	15693459	15693459	15693459	15693459	15693459	15693459
TAXABLE INCOME	-3350043	-1197305	740159	2483876	2483876	2483876	2483876	2483876	2483876
CURRENT INCOME TAX	-1608021	-574707	355276	1192261	1192261	1192261	1192261	1192261	1192261
DEFERRED INCOME TAX	-468874	-1502188	-2432171	-3269156	-3269156	-3269156	-3269156	-3269156	-3269156
TOTAL INCOME TAXES	-2076895	-2076895	-2076895	-2076895	-2076895	-2076895	-2076895	-2076895	-2076895
NET INCOME (BOOK)	-2249970	-2249970	-2249970	-2249970	-2249970	-2249970	-2249970	-2249970	-2249970
SOURCES OF FUNDS									
NET INCOME	-2249970	-2249970	-2249970	-2249970	-2249970	-2249970	-2249970	-2249970	-2249970
FINANCIAL DEPRECIATION	22504200	22504200	22504200	22504200	22504200	22504200	22504200	22504200	22504200
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-468874	-1502188	-2432171	-3269156	-3269156	-3269156	-3269156	-3269156	-3269156
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	19785356	18752042	17822059	16985074	16985074	16985074	16985074	16985074	16985074
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	19785356	18752042	17822059	16985074	16985074	16985074	16985074	16985074	16985074
CUMULATIVE NET CASH GENERATED	243668161	262420203	280242262	297227336	314212410	331197484	348182558	365167632	382152706
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545122

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 1C2 PROCESS 8/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO KENAI

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	70800	70800	70800	70800	1916000	70800
COST OF SERVICE ($/BBL)	1.694	1.694	1.694	1.694	37.268	1.863
TOTAL REVENUE	43767335	43767335	43767335	43767335	875346700	43767335
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	25590000	25590000	25590000	25590000	511800000	25590000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	22504200	22504200	22504200	22504200	450084000	22504200
TOTAL EXPENSES	48094200	48094200	48094200	48094200	961884000	48094200
INCOME BEFORE TAXES	-4326865	-4326865	-4326865	-4326865	-86537300	-4326865
INVESTMENT TAX CREDIT	0	0	0	0	45008400	2250420
TAX DEPRECIATION	15693459	15693459	15693459	15693459	450084002	22504200
TAXABLE INCOME	2483876	2483876	2483876	2483876	-86537302	-4326865
CURRENT INCOME TAX	1192261	1192261	1192261	1192261	-86546302	-4327315
DEFERRED INCOME TAX	-3269156	-3269156	-3269156	-3269156	2	0
TOTAL INCOME TAXES	-2076895	-2076895	-2076895	-2076895	-86546300	-4327315
NET INCOME (BOOK)	-2249970	-2249970	-2249970	-2249970	9000	450
SOURCES OF FUNDS						
NET INCOME	-2249970	-2249970	-2249970	-2249970	9000	450
FINANCIAL DEPRECIATION	22504200	22504200	22504200	22504200	450084000	22504200
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-3269156	-3269156	-3269156	-3269156	2	0
NET ADDITIONS TO EQUITY	0	0	0	0	450084000	22504200
TOTAL SOURCES	16985074	16985074	16985074	16985074	900177002	45008850
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	450084000	22504200
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	450084000	22504200
NET CASH GENERATED DURING YEAR	16985074	16985074	16985074	16985074	450093002	22504650
CUMULATIVE NET CASH GENERATED	39913778O	416122854	43310792R	450093002	5600555213	280027761
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545123

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE ID PROCESS 8/8 GAS AT PRUDHOE -EQ. GAS/C3+ BTU -LIQ PL TO FAIRBANKS

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	90400	90400	90400	90400	90400	90400	90400
COST OF SERVICE ($/BBL)	.755	.755	.755	.755	.755	.755	.755	.755	.755
TOTAL REVENUE	0	0	24897425	24897425	24897425	24897425	24897425	24897425	24897425
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	14200000	14200000	14200000	14200000	14200000	14200000	14200000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	13243800	13243800	13243800	13243800	13243800	13243800	13243800
TOTAL EXPENSES	0	0	27443800	27443800	27443800	27443800	27443800	27443800	27443800
INCOME BEFORE TAXES	0	0	-2546375	-2546375	-2546375	-2546375	-2546375	-2546375	-2546375
INVESTMENT TAX CREDIT	0	0	26487600	0	0	0	0	0	0
TAX DEPRECIATION	0	0	26487600	23838840	21454956	19309460	17378514	15640663	14076597
TAXABLE INCOME	0	0	-15790175	-13141415	-10757531	-8612035	-6681089	-4943238	-3379172
CURRENT INCOME TAX	0	0	-34066884	-6307879	-5163615	-4133777	-3206923	-2372754	-1622002
DEFERRED INCOME TAX	0	0	6357024	5085619	3941355	2911517	1984663	1150494	399742
TOTAL INCOME TAXES	0	0	-27709860	-1222260	-1222260	-1222260	-1222260	-1222260	-1222260
NET INCOME (BOOK)	0	0	25163485	-1324115	-1324115	-1324115	-1324115	-1324115	-1324115
SOURCES OF FUNDS									
NET INCOME	0	0	25163485	-1324115	-1324115	-1324115	-1324115	-1324115	-1324115
FINANCIAL DEPRECIATION	0	0	13243800	13243800	13243800	13243800	13243800	13243800	13243800
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	6357024	5085619	3941355	2911517	1984663	1150494	399742
NET ADDITIONS TO EQUITY	132438000	132438000	0	0	0	0	0	0	0
TOTAL SOURCES	132438000	132438000	44764309	17005304	15861040	14831202	13904348	13070179	12319427
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	132438000	132438000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	132438000	132438000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	44764309	17005304	15861040	14831202	13904348	13070179	12319427
CUMULATIVE NET CASH GENERATED	0	0	44764309	61769613	77630653	92461855	106366203	119436382	131755809
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545124

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE ID PROCESS 8/8 GAS AT PRUDHOE -EQ. GAS/C3+ BTU -LIQ PL TO FAIRBANKS

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	90400	90400	90400	90400	90400	90400	90400	90400	90400
COST OF SERVICE ($/BBL)	.755	.755	.755	.755	.755	.755	.755	.755	.755
TOTAL REVENUE	24897425	24897425	24897425	24897425	24897425	24897425	24897425	24897425	24897425
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	14200000	14200000	14200000	14200000	14200000	14200000	14200000	14200000	14200000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	13243800	13243800	13243800	13243800	13243800	13243800	13243800	13243800	13243800
TOTAL EXPENSES	27443800	27443800	27443800	27443800	27443800	27443800	27443800	27443800	27443800
INCOME BEFORE TAXES	-2546375	-2546375	-2546375	-2546375	-2546375	-2546375	-2546375	-2546375	-2546375
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	12668937	11402043	10261839	9235655	9235655	9235655	9235655	9235655	9235655
TAXABLE INCOME	-1971512	-704618	435586	1461770	1461770	1461770	1461770	1461770	1461770
CURRENT INCOME TAX	-946326	-338217	209081	701649	701649	701649	701649	701649	701649
DEFERRED INCOME TAX	-275934	-884043	-1431341	-1923909	-1923909	-1923909	-1923909	-1923909	-1923909
TOTAL INCOME TAXES	-1222260	-1222260	-1222260	-1222260	-1222260	-1222260	-1222260	-1222260	-1222260
NET INCOME (BOOK)	-1324115	-1324115	-1324115	-1324115	-1324115	-1324115	-1324115	-1324115	-1324115
SOURCES OF FUNDS									
NET INCOME	-1324115	-1324115	-1324115	-1324115	-1324115	-1324115	-1324115	-1324115	-1324115
FINANCIAL DEPRECIATION	13243800	13243800	13243800	13243800	13243800	13243800	13243800	13243800	13243800
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-275934	-884043	-1431341	-1923909	-1923909	-1923909	-1923909	-1923909	-1923909
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	11643751	11035642	10488344	9995776	9995776	9995776	9995776	9995776	9995776
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	11643751	11035642	10488344	9995776	9995776	9995776	9995776	9995776	9995776
CUMULATIVE NET CASH GENERATED	143399560	154435202	164923546	174919322	184915098	194910874	204906650	214902426	224898202
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545125

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE ID PROCESS 8/8 GAS AT PRUDHOE -EQ. GAS/C3+ BTU -LIQ PL TO FAIRBANKS

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	90400	90400	90400	90400	1808000	90400
COST OF SERVICE ($/BBL)	.755	.755	.755	.755	16.610	.831
TOTAL REVENUE	24897425	24897425	24897425	24897425	497948500	24897425
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	14200000	14200000	14200000	14200000	284000000	14200000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	13243800	13243800	13243800	13243800	264876000	13243800
TOTAL EXPENSES	27443800	27443800	27443800	27443800	548876000	27443800
INCOME BEFORE TAXES	-2546375	-2546375	-2546375	-2546375	-50927500	-2546375
INVESTMENT TAX CREDIT	0	0	0	0	26487600	1324380
TAX DEPRECIATION	9235655	9235655	9235655	9235655	264875999	13243800
TAXABLE INCOME	1461770	1461770	1461770	1461770	-50927499	-2546375
CURRENT INCOME TAX	701649	701649	701649	701649	-50932806	-2546640
DEFERRED INCOME TAX	-1923909	-1923909	-1923909	-1923909	6	0
TOTAL INCOME TAXES	-1222260	-1222260	-1222260	-1222260	-50932800	-2546640
NET INCOME (BOOK)	-1324115	-1324115	-1324115	-1324115	5300	265
SOURCES OF FUNDS						
NET INCOME	-1324115	-1324115	-1324115	-1324115	5300	265
FINANCIAL DEPRECIATION	13243800	13243800	13243800	13243800	264876000	13243800
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1923909	-1923909	-1923909	-1923909	6	0
NET ADDITIONS TO EQUITY	0	0	0	0	264876000	13243800
TOTAL SOURCES	9995776	9995776	9995776	9995776	529757306	26487865
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	264876000	13243800
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	264876000	13243800
NET CASH GENERATED DURING YEAR	9995776	9995776	9995776	9995776	264881306	13244065
CUMULATIVE NET CASH GENERATED	234893978	244889754	254885530	264881306	3295946272	164797314
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545126

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IE PROCESS 8/8 GAS AT PRUDHOE -EQ. GAS/C3+ BTU -LIQ PL TO KENAI

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	90400	90400	90400	90400	90400	90400	90400
COST OF SERVICE ($/BBL)	1.484	1.484	1.484	1.484	1.484	1.484	1.484	1.484	1.484
TOTAL REVENUE	0	0	48968406	48968406	48968406	48968406	48968406	48968406	48968406
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	27670000	27670000	27670000	27670000	27670000	27670000	27670000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	26368200	26368200	26368200	26368200	26368200	26368200	26368200
TOTAL EXPENSES	0	0	54038200	54038200	54038200	54038200	54038200	54038200	54038200
INCOME BEFORE TAXES	0	0	-5069794	-5069794	-5069794	-5069794	-5069794	-5069794	-5069794
INVESTMENT TAX CREDIT	0	0	52736400	0	0	0	0	0	0
TAX DEPRECIATION	0	0	52736400	47462760	42716484	38444836	34600352	31140317	28026285
TAXABLE INCOME	0	0	-31437994	-26164354	-21418078	-17146430	-13301946	-9841911	-6727879
CURRENT INCOME TAX	0	0	-67826637	-12558890	-10280077	-8230286	-6384934	-4724117	-3229382
DEFERRED INCOME TAX	0	0	12656736	10125389	7847176	5796785	3951433	2290616	795881
TOTAL INCOME TAXES	0	0	-55169901	-2433501	-2433501	-2433501	-2433501	-2433501	-2433501
NET INCOME (BOOK)	0	0	50100107	-2636293	-2636293	-2636293	-2636293	-2636293	-2636293
SOURCES OF FUNDS									
NET INCOME	0	0	50100107	-2636293	-2636293	-2636293	-2636293	-2636293	-2636293
FINANCIAL DEPRECIATION	0	0	26368200	26368200	26368200	26368200	26368200	26368200	26368200
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	12656736	10125389	7847176	5796785	3951433	2290616	795881
NET ADDITIONS TO EQUITY	263682000	263682000	0	0	0	0	0	0	0
TOTAL SOURCES	263682000	263682000	89125043	33857296	31579083	29528692	27683340	26022523	24527788
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	263682000	263682000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	263682000	263682000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	89125043	33857296	31579083	29528692	27683340	26022523	24527788
CUMULATIVE NET CASH GENERATED	0	0	89125043	122982339	154561422	184090114	211773454	237795977	262323765
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545127

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IE PROCESS 8/8 GAS AT PRUDHOE -EQ. GAS/C3+ BTU -LIQ PL TO KENAI

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	90400	90400	90400	90400	90400	90400	90400	90400	90400
COST OF SERVICE ($/BBL)	1.484	1.484	1.484	1.484	1.484	1.484	1.484	1.484	1.484
TOTAL REVENUE	48968406	48968406	48968406	48968406	48968406	48968406	48968406	48968406	48968406
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	27670000	27670000	27670000	27670000	27670000	27670000	27670000	27670000	27670000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	26368200	26368200	26368200	26368200	26368200	26368200	26368200	26368200	26368200
TOTAL EXPENSES	54038200	54038200	54038200	54038200	54038200	54038200	54038200	54038200	54038200
INCOME BEFORE TAXES	-5069794	-5069794	-5069794	-5069794	-5069794	-5069794	-5069794	-5069794	-5069794
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	25223657	22701291	20431162	18388046	18388046	18388046	18388046	18388046	18388046
TAXABLE INCOME	-3925251	-1402385	867244	2910360	2910360	2910360	2910360	2910360	2910360
CURRENT INCOME TAX	-1884120	-673385	416277	1396973	1396973	1396973	1396973	1396973	1396973
DEFERRED INCOME TAX	-549381	-1760116	-2849778	-3830474	-3830474	-3830474	-3830474	-3830474	-3830474
TOTAL INCOME TAXES	-2433501	-2433501	-2433501	-2433501	-2433501	-2433501	-2433501	-2433501	-2433501
NET INCOME (BOOK)	-2636293	-2636293	-2636293	-2636293	-2636293	-2636293	-2636293	-2636293	-2636293
SOURCES OF FUNDS									
NET INCOME	-2636293	-2636293	-2636293	-2636293	-2636293	-2636293	-2636293	-2636293	-2636293
FINANCIAL DEPRECIATION	26368200	26368200	26368200	26368200	26368200	26368200	26368200	26368200	26368200
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-549381	-1760116	-2849778	-3830474	-3830474	-3830474	-3830474	-3830474	-3830474
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	23182526	21971791	20882129	19901433	19901433	19901433	19901433	19901433	19901433
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	23182526	21971791	20882129	19901433	19901433	19901433	19901433	19901433	19901433
CUMULATIVE NET CASH GENERATED	285506291	307478082	328360211	348261644	368163077	388064510	407965943	427867376	447768809
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545128

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IE PROCESS 8/8 GAS AT PRUDHOE -EQ. GAS/C3+ BTU -LIQ RL TO KENAI

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	90400	90400	90400	90400	1808000	90400
COST OF SERVICE ($/BBL)	1.484	1.484	1.484	1.484	32.648	1.632
TOTAL REVENUE	48968406	48968406	48968406	48968406	979368120	48968406
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	27670000	27670000	27670000	27670000	553400000	27670000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	26368200	26368200	26368200	26368200	527364000	26368200
TOTAL EXPENSES	54038200	54038200	54038200	54038200	1080764000	54038200
INCOME BEFORE TAXES	-5069794	-5069794	-5069794	-5069794	-101395880	-5069794
INVESTMENT TAX CREDIT	0	0	0	0	52736400	2636820
TAX DEPRECIATION	18388046	18388046	18388046	18388046	527364004	26368200
TAXABLE INCOME	2910360	2910360	2910360	2910360	-101395884	-5069794
CURRENT INCOME TAX	1396973	1396973	1396973	1396973	-101406421	-5070321
DEFERRED INCOME TAX	-3830474	-3830474	-3830474	-3830474	1	0
TOTAL INCOME TAXES	-2433501	-2433501	-2433501	-2433501	-101406420	-5070321
NET INCOME (BOOK)	-2636293	-2636293	-2636293	-2636293	10540	527
SOURCES OF FUNDS						
NET INCOME	-2636293	-2636293	-2636293	-2636293	10540	527
FINANCIAL DEPRECIATION	26368200	26368200	26368200	26368200	527364000	26368200
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-3830474	-3830474	-3830474	-3830474	1	0
NET ADDITIONS TO EQUITY	0	0	0	0	527364000	26368200
TOTAL SOURCES	19901433	19901433	19901433	19901433	1054738541	52736927
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	527364000	26368200
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	527364000	26368200
NET CASH GENERATED DURING YEAR	19901433	19901433	19901433	19901433	527374541	26368727
CUMULATIVE NET CASH GENERATED	467670242	487571675	507473108	527374541	1656177623	328108881
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545129

CASE II

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIA1 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	22800	22800	22800	22800	22800	22800	22800
COST OF SERVICE ($/BBL)	2.042	2.042	2.042	2.042	2.042	2.042	2.042	2.042	2.042
TOTAL REVENUE	0	0	16990858	16990858	16990858	16990858	16990858	16990858	16990858
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	11000000	11000000	11000000	11000000	11000000	11000000	11000000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	7416900	7416900	7416900	7416900	7416900	7416900	7416900
TOTAL EXPENSES	0	0	18416900	18416900	18416900	18416900	18416900	18416900	18416900
INCOME BEFORE TAXES	0	0	-1426042	-1426042	-1426042	-1426042	-1426042	-1426042	-1426042
INVESTMENT TAX CREDIT	0	0	14833800	0	0	0	0	0	0
TAX DEPRECIATION	0	0	14833800	13350420	12015378	10813840	9732456	8759211	7883290
TAXABLE INCOME	0	0	-8842942	-7359562	-6024520	-4822982	-3741598	-2768353	-1892432
CURRENT INCOME TAX	0	0	-19078412	-3532590	-2891769	-2315031	-1795967	-1328809	-908367
DEFERRED INCOME TAX	0	0	3560112	2848090	2207269	1630531	1111467	644309	223867
TOTAL INCOME TAXES	0	0	-15518300	-684500	-684500	-684500	-684500	-684500	-684500
NET INCOME (BOOK)	0	0	14092258	-741542	-741542	-741542	-741542	-741542	-741542
SOURCES OF FUNDS									
NET INCOME	0	0	14092258	-741542	-741542	-741542	-741542	-741542	-741542
FINANCIAL DEPRECIATION	0	0	7416900	7416900	7416900	7416900	7416900	7416900	7416900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	3560112	2848090	2207269	1630531	1111467	644309	223867
NET ADDITIONS TO EQUITY	74169000	74169000	0	0	0	0	0	0	0
TOTAL SOURCES	74169000	74169000	25069270	9523448	8882627	8305889	7786825	7319667	6899225
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	74169000	74169000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	74169000	74169000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	25069270	9523448	8882627	8305889	7786825	7319667	6899225
CUMULATIVE NET CASH GENERATED	0	0	25069270	34592718	43475345	51781234	59568059	66887726	73786951
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545131

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIA1 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	22800	22800	22800	22800	22800	22800	22800	22800	22800
COST OF SERVICE ($/BBL)	2.042	2.042	2.042	2.042	2.042	2.042	2.042	2.042	2.042
TOTAL REVENUE	16990858	16990858	16990858	16990858	16990858	16990858	16990858	16990858	16990858
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	11000000	11000000	11000000	11000000	11000000	11000000	11000000	11000000	11000000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	7416900	7416900	7416900	7416900	7416900	7416900	7416900	7416900	7416900
TOTAL EXPENSES	18416900	18416900	18416900	18416900	18416900	18416900	18416900	18416900	18416900
INCOME BEFORE TAXES	-1426042	-1426042	-1426042	-1426042	-1426042	-1426042	-1426042	-1426042	-1426042
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	7094961	6385464	5746918	5172226	5172226	5172226	5172226	5172226	5172226
TAXABLE INCOME	-1104103	-394606	243940	818632	818632	818632	818632	818632	818632
CURRENT INCOME TAX	-529969	-189411	117091	392943	392943	392943	392943	392943	392943
DEFERRED INCOME TAX	-154531	-495089	-801591	-1077443	-1077443	-1077443	-1077443	-1077443	-1077443
TOTAL INCOME TAXES	-684500	-684500	-684500	-684500	-684500	-684500	-684500	-684500	-684500
NET INCOME (BOOK)	-741542	-741542	-741542	-741542	-741542	-741542	-741542	-741542	-741542
SOURCES OF FUNDS									
NET INCOME	-741542	-741542	-741542	-741542	-741542	-741542	-741542	-741542	-741542
FINANCIAL DEPRECIATION	7416900	7416900	7416900	7416900	7416900	7416900	7416900	7416900	7416900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-154531	-495089	-801591	-1077443	-1077443	-1077443	-1077443	-1077443	-1077443
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	6520827	6180269	5873747	5597915	5597915	5597915	5597915	5597915	5597915
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	6520827	6180269	5873767	5597915	5597915	5597915	5597915	5597915	5597915
CUMULATIVE NET CASH GENERATED	80307778	86488047	92361814	97959729	103557644	109155559	114753474	120351389	125949304
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545132

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIA1 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT ETHANE -LIQ PL TO FAIRBANKS

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (RBLS)	22800	22800	22800	22800	456000	22800
COST OF SERVICE ($/BBL)	2.042	2.042	2.042	2.042	44.924	2.246
TOTAL REVENUE	16990858	16990858	16990858	16990858	339817160	16990858
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	11000000	11000000	11000000	11000000	220000000	11000000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	7416900	7416900	7416900	7416900	148338000	7416900
TOTAL EXPENSES	18416900	18416900	18416900	18416900	368338000	18416900
INCOME BEFORE TAXES	-1426042	-1426042	-1426042	-1426042	-28520840	-1426042
INVESTMENT TAX CREDIT	0	0	0	0	14833800	741690
TAX DEPRECIATION	5172226	5172226	5172226	5172226	148337998	7416900
TAXABLE INCOME	818632	818632	818632	818632	-28520838	-1426042
CURRENT INCOME TAX	392943	392943	392943	392943	-28523804	-1426190
DEFERRED INCOME TAX	-1077443	-1077443	-1077443	-1077443	4	0
TOTAL INCOME TAXES	-684500	-684500	-684500	-684500	-28523800	-1426190
NET INCOME (BOOK)	-741542	-741542	-741542	-741542	2960	148
SOURCES OF FUNDS						
NET INCOME	-741542	-741542	-741542	-741542	2960	148
FINANCIAL DEPRECIATION	7416900	7416900	7416900	7416900	148338000	7416900
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1077443	-1077443	-1077443	-1077443	4	0
NET ADDITIONS TO EQUITY	0	0	0	0	148338000	7416900
TOTAL SOURCES	5597915	5597915	5597915	5597915	296678964	14833948
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	148338000	7416900
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	148338000	7416900
NET CASH GENERATED DURING YEAR	5597915	5597915	5597915	5597915	148340964	7417048
CUMULATIVE NET CASH GENERATED	131547219	137145134	142743049	148340964	1845022467	92291120
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545133

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIB1 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -USE OLD PL TO HAINES

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	22800	22800	22800	22800	22800	22800	22800
COST OF SERVICE ($/BBL)	4.545	4.545	4.545	4.545	4.545	4.545	4.545	4.545	4.545
TOTAL REVENUE	0	0	37820544	37820544	37820544	37820544	37820544	37820544	37820544
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	25510000	25510000	25510000	25510000	25510000	25510000	25510000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	15240900	15240900	15240900	15240900	15240900	15240900	15240900
TOTAL EXPENSES	0	0	40750900	40750900	40750900	40750900	40750900	40750900	40750900
INCOME BEFORE TAXES	0	0	-2930356	-2930356	-2930356	-2930356	-2930356	-2930356	-2930356
INVESTMENT TAX CREDIT	0	0	30481800	0	0	0	0	0	0
TAX DEPRECIATION	0	0	30481800	27433620	24690258	22221232	19999109	17999198	16199278
TAXABLE INCOME	0	0	-18171256	-15123076	-12379714	-9910688	-7688565	-5688654	-3888734
CURRENT INCOME TAX	0	0	-39204003	-7259077	-5942263	-4757130	-3690511	-2730554	-1866593
DEFERRED INCOME TAX	0	0	7315632	5852506	4535692	3350559	2283940	1323983	460022
TOTAL INCOME TAXES	0	0	-31888371	-1406571	-1406571	-1406571	-1406571	-1406571	-1406571
NET INCOME (BOOK)	0	0	28958015	-1523785	-1523785	-1523785	-1523785	-1523785	-1523785
SOURCES OF FUNDS									
NET INCOME	0	0	28958015	-1523785	-1523785	-1523785	-1523785	-1523785	-1523785
FINANCIAL DEPRECIATION	0	0	15240900	15240900	15240900	15240900	15240900	15240900	15240900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	7315632	5852506	4535692	3350559	2283940	1323983	460022
NET ADDITIONS TO EQUITY	152409000	152409000	0	0	0	0	0	0	0
TOTAL SOURCES	152409000	152409000	51514547	19569621	18252807	17067674	16001055	15041098	14177137
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	152409000	152409000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	152409000	152409000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	51514547	19569621	18252807	17067674	16001055	15041098	14177137
CUMULATIVE NET CASH GENERATED	0	0	51514547	71084168	89336975	106404649	122405704	137446802	151623939
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545134

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 11B1 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -USE OLD PL TO HAINES

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	22800	22800	22800	22800	22800	22800	22800	22800	22800
COST OF SERVICE ($/BBL)	4.545	4.545	4.545	4.545	4.545	4.545	4.545	4.545	4.545
TOTAL REVENUE	37820544	37820544	37820544	37820544	37820544	37820544	37820544	37820544	37820544
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	25510000	25510000	25510000	25510000	25510000	25510000	25510000	25510000	25510000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	15240900	15240900	15240900	15240900	15240900	15240900	15240900	15240900	15240900
TOTAL EXPENSES	40750900	40750900	40750900	40750900	40750900	40750900	40750900	40750900	40750900
INCOME BEFORE TAXES	-2930356	-2930356	-2930356	-2930356	-2930356	-2930356	-2930356	-2930356	-2930356
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	14579350	13121415	11809274	10628346	10628346	10628346	10628346	10628346	10628346
TAXABLE INCOME	-2268806	-810871	501270	1682198	1682198	1682198	1682198	1682198	1682198
CURRENT INCOME TAX	-1089027	-389218	240610	807455	807455	807455	807455	807455	807455
DEFERRED INCOME TAX	-317544	-1017353	-1647181	-2214026	-2214026	-2214026	-2214026	-2214026	-2214026
TOTAL INCOME TAXES	-1406571	-1406571	-1406571	-1406571	-1406571	-1406571	-1406571	-1406571	-1406571
NET INCOME (BOOK)	-1523785	-1523785	-1523785	-1523785	-1523785	-1523785	-1523785	-1523785	-1523785
SOURCES OF FUNDS									
NET INCOME	-1523785	-1523785	-1523785	-1523785	-1523785	-1523785	-1523785	-1523785	-1523785
FINANCIAL DEPRECIATION	15240900	15240900	15240900	15240900	15240900	15240900	15240900	15240900	15240900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-317544	-1017353	-1647181	-2214026	-2214026	-2214026	-2214026	-2214026	-2214026
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	13399571	12699762	12069934	11503089	11503089	11503089	11503089	11503089	11503089
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	13399571	12699762	12069934	11503089	11503089	11503089	11503089	11503089	11503089
CUMULATIVE NET CASH GENERATED	165023510	177723272	189793206	201296295	212799384	224302473	235805562	247308651	258811740
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545135

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIB1 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -USE OLD PL TO HAINES

TIME PERIOD	1999	2000	2001	2002	9999	8880
DAILY TRANSPORTATION VOLUME (BBLS)	22800	22800	22800	22800	456000	22800
COST OF SERVICE ($/BBL)	4.545	4.545	4.545	4.545	99.990	5.000
TOTAL REVENUE	37820544	37820544	37820544	37820544	756410880	37820544
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	25510000	25510000	25510000	25510000	510200000	25510000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	15240900	15240900	15240900	15240900	304818000	15240900
TOTAL EXPENSES	40750900	40750900	40750900	40750900	815018000	40750900
INCOME BEFORE TAXES	-2930356	-2930356	-2930356	-2930356	-58607120	-2930356
INVESTMENT TAX CREDIT	0	0	0	0	30481800	1524090
TAX DEPRECIATION	10628346	10628346	10628346	10628346	304817994	15240900
TAXABLE INCOME	1682198	1682198	1682198	1682198	-58607114	-2930356
CURRENT INCOME TAX	807455	807455	807455	807455	-58613216	-2930661
DEFERRED INCOME TAX	-2214026	-2214026	-2214026	-2214026	-6	0
TOTAL INCOME TAXES	-1406571	-1406571	-1406571	-1406571	-58613220	-2930661
NET INCOME (BOOK)	-1523785	-1523785	-1523785	-1523785	6100	305
SOURCES OF FUNDS						
NET INCOME	-1523785	-1523785	-1523785	-1523785	6100	305
FINANCIAL DEPRECIATION	15240900	15240900	15240900	15240900	304818000	15240900
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2214026	-2214026	-2214026	-2214026	-6	0
NET ADDITIONS TO EQUITY	0	0	0	0	304818000	15240900
TOTAL SOURCES	11503089	11503089	11503089	11503089	609642096	30482105
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	304818000	15240900
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	304818000	15240900
NET CASH GENERATED DURING YEAR	11503089	11503089	11503089	11503089	304824096	15241205
CUMULATIVE NET CASH GENERATED	270314829	281817918	293321007	304824096	3792958727	189647936
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545136

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIB2 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -NEW PL TO HAINES

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	22800	22800	22800	22800	22800	22800	22800
COST OF SERVICE ($/BBL)	4.542	4.542	4.542	4.542	4.542	4.542	4.542	4.542	4.542
TOTAL REVENUE	0	0	37800572	37800572	37800572	37800572	37800572	37800572	37800572
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	21500000	21500000	21500000	21500000	21500000	21500000	21500000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	20180700	20180700	20180700	20180700	20180700	20180700	20180700
TOTAL EXPENSES	0	0	41680700	41680700	41680700	41680700	41680700	41680700	41680700
INCOME BEFORE TAXES	0	0	-3880128	-3880128	-3880128	-3880128	-3880128	-3880128	-3880128
INVESTMENT TAX CREDIT	0	0	40361400	0	0	0	0	0	0
TAX DEPRECIATION	0	0	40361400	36325260	32692734	29423461	26481115	23833003	21449703
TAXABLE INCOME	0	0	-24060828	-20024688	-16392162	-13122889	-10180543	-7532431	-5149131
CURRENT INCOME TAX	0	0	-51910597	-9611850	-7868238	-6298986	-4886660	-3615567	-2471583
DEFERRED INCOME TAX	0	0	9686736	7749389	6005777	4436525	3024199	1753106	609122
TOTAL INCOME TAXES	0	0	-42223861	-1862461	-1862461	-1862461	-1862461	-1862461	-1862461
NET INCOME (BOOK)	0	0	38343733	-2017667	-2017667	-2017667	-2017667	-2017667	-2017667
SOURCES OF FUNDS									
NET INCOME	0	0	38343733	-2017667	-2017667	-2017667	-2017667	-2017667	-2017667
FINANCIAL DEPRECIATION	0	0	20180700	20180700	20180700	20180700	20180700	20180700	20180700
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	9686736	7749389	6005777	4436525	3024199	1753106	609122
NET ADDITIONS TO EQUITY	201807000	201807000	0	0	0	0	0	0	0
TOTAL SOURCES	201807000	201807000	68211169	25912422	24168810	22599558	21187232	19916139	18772155
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	201807000	201807000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	201807000	201807000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	68211169	25912422	24168810	22599558	21187232	19916139	18772155
CUMULATIVE NET CASH GENERATED	0	0	68211169	94123591	118292401	140891959	162079191	181995330	200767485
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545137

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 1182 PROCESS 1/8 GAS A)(PRUDHOE -EXTRACT ETHANE+ -NEW PL TO HAINES

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	22800	22800	22800	22800	22800	22800	22800	22800	22800
COST OF SERVICE ($/BBL)	4.542	4.542	4.542	4.542	4.542	4.542	4.542	4.542	4.542
TOTAL REVENUE	37800572	37800572	37800572	37800572	37800572	37800572	37800572	37800572	37800572
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	21500000	21500000	21500000	21500000	21500000	21500000	21500000	21500000	21500000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	20180700	20180700	20180700	20180700	20180700	20180700	20180700	20180700	20180700
TOTAL EXPENSES	41680700	41680700	41680700	41680700	41680700	41680700	41680700	41680700	41680700
INCOME BEFORE TAXES	-3880128	-3880128	-3880128	-3880128	-3880128	-3880128	-3880128	-3880128	-3880128
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	19304732	17374259	15636833	14073150	14073150	14073150	14073150	14073150	14073150
TAXABLE INCOME	-3004160	-1073687	663739	2227422	2227422	2227422	2227422	2227422	2227422
CURRENT INCOME TAX	-1441997	-515370	318595	1069163	1069163	1069163	1069163	1069163	1069163
DEFERRED INCOME TAX	-420464	-1347091	-2181056	-2931624	-2931624	-2931624	-2931624	-2931624	-2931624
TOTAL INCOME TAXES	-1862461	-1862461	-1862461	-1862461	-1862461	-1862461	-1862461	-1862461	-1862461
NET INCOME (BOOK)	-2017667	-2017667	-2017667	-2017667	-2017667	-2017667	-2017667	-2017667	-2017667
SOURCES OF FUNDS									
NET INCOME	-2017667	-2017667	-2017667	-2017667	-2017667	-2017667	-2017667	-2017667	-2017667
FINANCIAL DEPRECIATION	20180700	20180700	20180700	20180700	20180700	20180700	20180700	20180700	20180700
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-420464	-1347091	-2181056	-2931624	-2931624	-2931624	-2931624	-2931624	-2931624
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	17742569	16815942	15981977	15231409	15231409	15231409	15231409	15231409	15231409
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	17742569	16815942	15981977	15231409	15231409	15231409	15231409	15231409	15231409
CUMULATIVE NET CASH GENERATED	218510054	235325996	251307973	266539382	281770791	297002200	312233609	327465018	342696427
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545138

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 11B2 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -NEW PL TO HAINES

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	22800	22800	22800	22800	456000	22800
COST OF SERVICE ($/BBL)	4.542	4.542	4.542	4.542	99.929	4.996
TOTAL REVENUE	37800572	37800572	37800572	37800572	756011440	37800572
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	21500000	21500000	21500000	21500000	430000000	21500000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	20180700	20180700	20180700	20180700	403614000	20180700
TOTAL EXPENSES	41680700	41680700	41680700	41680700	833614000	41680700
INCOME BEFORE TAXES	-3880128	-3880128	-3880128	-3880128	-77602560	-3880128
INVESTMENT TAX CREDIT	0	0	0	0	40361400	2018070
TAX DEPRECIATION	14073150	14073150	14073150	14073150	403614000	20180700
TAXABLE INCOME	2227422	2227422	2227422	2227422	-77602560	-3880128
CURRENT INCOME TAX	1069163	1069163	1069163	1069163	-77610623	-3880531
DEFERRED INCOME TAX	-2931624	-2931624	-2931624	-2931624	3	0
TOTAL INCOME TAXES	-1862461	-1862461	-1862461	-1862461	-77610620	-3880531
NET INCOME (BOOK)	-2017667	-2017667	-2017667	-2017667	8060	403
SOURCES OF FUNDS						
NET INCOME	-2017667	-2017667	-2017667	-2017667	8060	403
FINANCIAL DEPRECIATION	20180700	20180700	20180700	20180700	403614000	20180700
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2931624	-2931624	-2931624	-2931624	3	0
NET ADDITIONS TO EQUITY	0	0	0	0	403614000	20180700
TOTAL SOURCES	15231409	15231409	15231409	15231409	807236063	40361803
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	403614000	20180700
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	403614000	20180700
NET CASH GENERATED DURING YEAR	15231409	15231409	15231409	15231409	403622063	20181103
CUMULATIVE NET CASH GENERATED	357927836	373159245	388390654	403622063	5022312374	251115619
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545139

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 11C1 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO KENAI

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	22800	22800	22800	22800	22800	22800	22800
COST OF SERVICE ($/BBL)	3.759	3.759	3.759	3.759	3.759	3.759	3.759	3.759	3.759
TOTAL REVENUE	0	0	31286312	31286312	31286312	31286312	31286312	31286312	31286312
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	19815000	19815000	19815000	19815000	19815000	19815000	19815000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	14201900	14201900	14201900	14201900	14201900	14201900	14201900
TOTAL EXPENSES	0	0	34016900	34016900	34016900	34016900	34016900	34016900	34016900
INCOME BEFORE TAXES	0	0	-2730588	-2730588	-2730588	-2730588	-2730588	-2730588	-2730588
INVESTMENT TAX CREDIT	0	0	28403800	0	0	0	0	0	0
TAX DEPRECIATION	0	0	28403800	25563420	23007078	20706370	18635733	16772160	15094944
TAXABLE INCOME	0	0	-16932488	-14092108	-11535766	-9235058	-7164421	-5300848	-3623632
CURRENT INCOME TAX	0	0	-36531394	-6764212	-5537168	-4432828	-3438922	-2544407	-1739343
DEFERRED INCOME TAX	0	0	6816912	5453530	4226496	3122146	2128240	1233725	428661
TOTAL INCOME TAXES	0	0	-29714482	-1310682	-1310682	-1310682	-1310682	-1310682	-1310682
NET INCOME (BOOK)	0	0	26983894	-1419906	-1419906	-1419906	-1419906	-1419906	-1419906
SOURCES OF FUNDS									
NET INCOME	0	0	26983894	-1419906	-1419906	-1419906	-1419906	-1419906	-1419906
FINANCIAL DEPRECIATION	0	0	14201900	14201900	14201900	14201900	14201900	14201900	14201900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	6816912	5453530	4226496	3122146	2128240	1233725	428661
NET ADDITIONS TO EQUITY	142019000	142019000	0	0	0	0	0	0	0
TOTAL SOURCES	142019000	142019000	48002706	18235524	17008480	15904140	14910234	14015719	13210655
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	142019000	142019000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	142019000	142019000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	48002706	18235524	17008480	15904140	14910234	14015719	13210655
CUMULATIVE NET CASH GENERATED	0	0	48002706	66238230	83246710	99150850	114061084	128076803	141287458
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545140

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 11C1 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO KENAI

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	22800	22800	22800	22800	22800	22800	22800	22800	22800
COST OF SERVICE ($/BBL)	3.759	3.759	3.759	3.759	3.759	3.759	3.759	3.759	3.759
TOTAL REVENUE	31286312	31286312	31286312	31286312	31286312	31286312	31286312	31286312	31286312
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	19815000	19815000	19815000	19815000	19815000	19815000	19815000	19815000	19815000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	14201900	14201900	14201900	14201900	14201900	14201900	14201900	14201900	14201900
TOTAL EXPENSES	34016900	34016900	34016900	34016900	34016900	34016900	34016900	34016900	34016900
INCOME BEFORE TAXES	-2730588	-2730588	-2730588	-2730588	-2730588	-2730588	-2730588	-2730588	-2730588
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	13585449	12226905	11004214	9903793	9903793	9903793	9903793	9903793	9903793
TAXABLE INCOME	-2114137	-755593	467098	1567519	1567519	1567519	1567519	1567519	1567519
CURRENT INCOME TAX	-1014786	-362685	224207	752409	752409	752409	752409	752409	752409
DEFERRED INCOME TAX	-295896	-947997	-1534889	-2063091	-2063091	-2063091	-2063091	-2063091	-2063091
TOTAL INCOME TAXES	-1310682	-1310682	-1310682	-1310682	-1310682	-1310682	-1310682	-1310682	-1310682
NET INCOME (BOOK)	-1419906	-1419906	-1419906	-1419906	-1419906	-1419906	-1419906	-1419906	-1419906
SOURCES OF FUNDS									
NET INCOME	-1419906	-1419906	-1419906	-1419906	-1419906	-1419906	-1419906	-1419906	-1419906
FINANCIAL DEPRECIATION	14201900	14201900	14201900	14201900	14201900	14201900	14201900	14201900	14201900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-295896	-947997	-1534889	-2063091	-2063091	-2063091	-2063091	-2063091	-2063091
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	12486098	11833997	11247105	10718903	10718903	10718903	10718903	10718903	10718903
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	12486098	11833997	11247105	10718903	10718903	10718903	10718903	10718903	10718903
CUMULATIVE NET CASH GENERATED	153773556	165607553	176854658	187573561	198292464	209011367	219730270	230449173	241168076
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545141

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIC1 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT ETHANE+ -LIQ PL TO KENAI

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	22800	22800	22800	22800	456000	22800
COST OF SERVICE ($/BBL)	3.759	3.759	3.759	3.759	82.698	4.135
TOTAL REVENUE	31286312	31286312	31286312	31286312	625726240	31286312
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	19815000	19815000	19815000	19815000	396300000	19815000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	14201900	14201900	14201900	14201900	284038000	14201900
TOTAL EXPENSES	34016900	34016900	34016900	34016900	680338000	34016900
INCOME BEFORE TAXES	-2730588	-2730588	-2730588	-2730588	-54611760	-2730588
INVESTMENT TAX CREDIT	0	0	0	0	28403800	1420190
TAX DEPRECIATION	9903793	9903793	9903793	9903793	284038003	14201900
TAXABLE INCOME	1567519	1567519	1567519	1567519	-54611763	-2730588
CURRENT INCOME TAX	752409	752409	752409	752409	-54617448	-2730872
DEFERRED INCOME TAX	-2063091	-2063091	-2063091	-2063091	8	0
TOTAL INCOME TAXES	-1310682	-1310682	-1310682	-1310682	-54617440	-2730872
NET INCOME (BOOK)	-1419906	-1419906	-1419906	-1419906	5680	284
SOURCES OF FUNDS						
NET INCOME	-1419906	-1419906	-1419906	-1419906	5680	284
FINANCIAL DEPRECIATION	14201900	14201900	14201900	14201900	284038000	14201900
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2063091	-2063091	-2063091	-2063091	8	0
NET ADDITIONS TO EQUITY	0	0	0	0	284038000	14201900
TOTAL SOURCES	10718903	10718903	10718903	10718903	568081688	28404084
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	284038000	14201900
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	284038000	14201900
NET CASH GENERATED DURING YEAR	10718903	10718903	10718903	10718903	284043688	14202184
CUMULATIVE NET CASH GENERATED	251886979	262605882	273324785	284043688	3534385853	176719293
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545142

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIA2 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	8900	8900	8900	8900	8900	8900	8900
COST OF SERVICE ($/BBL)	4.627	4.627	4.627	4.627	4.627	4.627	4.627	4.627	4.627
TOTAL REVENUE	0	0	15032428	15032428	15032428	15032428	15032428	15032428	15032428
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	10240000	10240000	10240000	10240000	10240000	10240000	10240000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	5933200	5933200	5933200	5933200	5933200	5933200	5933200
TOTAL EXPENSES	0	0	16173200	16173200	16173200	16173200	16173200	16173200	16173200
INCOME BEFORE TAXES	0	0	-1140772	-1140772	-1140772	-1140772	-1140772	-1140772	-1140772
INVESTMENT TAX CREDIT	0	0	11866400	0	0	0	0	0	0
TAX DEPRECIATION	0	0	11866400	10679760	9611784	8650606	7785545	7006991	6306291
TAXABLE INCOME	0	0	-7073972	-5887332	-4819356	-3858178	-2993117	-2214563	-1513863
CURRENT INCOME TAX	0	0	-15261906	-2825919	-2313291	-1851925	-1436696	-1062990	-726654
DEFERRED INCOME TAX	0	0	2847936	2278349	1765721	1304355	889126	515420	179084
TOTAL INCOME TAXES	0	0	-12413970	-547570	-547570	-547570	-547570	-547570	-547570
NET INCOME (BOOK)	0	0	11273198	-593202	-593202	-593202	-593202	-593202	-593202
SOURCES OF FUNDS									
NET INCOME	0	0	11273198	-593202	-593202	-593202	-593202	-593202	-593202
FINANCIAL DEPRECIATION	0	0	5933200	5933200	5933200	5933200	5933200	5933200	5933200
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	2847936	2278349	1765721	1304355	889126	515420	179084
NET ADDITIONS TO EQUITY	59332000	59332000	0	0	0	0	0	0	0
TOTAL SOURCES	59332000	59332000	20054334	7618347	7105719	6644353	6229124	5855418	5519082
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	59332000	59332000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	59332000	59332000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	20054334	7618347	7105719	6644353	6229124	5855418	5519082
CUMULATIVE NET CASH GENERATED	0	0	20054334	27672681	34778400	41422753	47651877	53507295	59026377
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545143

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIA2 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	8900	8900	8900	8900	8900	8900	8900	8900	8900
COST OF SERVICE ($/BBL)	4.627	4.627	4.627	4.627	4.627	4.627	4.627	4.627	4.627
TOTAL REVENUE	15032428	15032428	15032428	15032428	15032428	15032428	15032428	15032428	15032428
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	10240000	10240000	10240000	10240000	10240000	10240000	10240000	10240000	10240000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	5933200	5933200	5933200	5933200	5933200	5933200	5933200	5933200	5933200
TOTAL EXPENSES	16173200	16173200	16173200	16173200	16173200	16173200	16173200	16173200	16173200
INCOME BEFORE TAXES	-1140772	-1140772	-1140772	-1140772	-1140772	-1140772	-1140772	-1140772	-1140772
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	5675662	5108096	4597286	4137558	4137558	4137558	4137558	4137558	4137558
TAXABLE INCOME	-883234	-315568	195142	654870	654870	654870	654870	654870	654870
CURRENT INCOME TAX	-423952	-151521	93668	314338	314338	314338	314338	314338	314338
DEFERRED INCOME TAX	-123618	-396049	-641238	-861908	-861908	-861908	-861908	-861908	-861908
TOTAL INCOME TAXES	-547570	-547570	-547570	-547570	-547570	-547570	-547570	-547570	-547570
NET INCOME (BOOK)	-593202	-593202	-593202	-593202	-593202	-593202	-593202	-593202	-593202
SOURCES OF FUNDS									
NET INCOME	-593202	-593202	-593202	-593202	-593202	-593202	-593202	-593202	-593202
FINANCIAL DEPRECIATION	5933200	5933200	5933200	5933200	5933200	5933200	5933200	5933200	5933200
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-123618	-396049	-641238	-861908	-861908	-861908	-861908	-861908	-861908
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	5216380	4943949	4698760	4478090	4478090	4478090	4478090	4478090	4478090
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	5216380	4943949	4698760	4478090	4478090	4478090	4478090	4478090	4478090
CUMULATIVE NET CASH GENERATED	64242757	69186706	73885466	78363556	82841646	87319736	91797826	96275916	100754006
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545144

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIA2 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	8900	8900	8900	8900	178000	8900
COST OF SERVICE ($/BBL)	4.627	4.627	4.627	4.627	101.794	5.090
TOTAL REVENUE	1503. 28	15032428	15032428	15032428	300648560	15032428
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	10240000	10240000	10240000	10240000	204800000	10240000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	5933200	5933200	5933200	5933200	118664000	5933200
TOTAL EXPENSES	16173200	16173200	16173200	16173200	323464000	16173200
INCOME BEFORE TAXES	-1140772	-1140772	-1140772	-1140772	-22815440	-1140772
INVESTMENT TAX CREDIT	0	0	0	0	11866400	593320
TAX DEPRECIATION	4137558	4137558	4137558	4137558	118664002	5933200
TAXABLE INCOME	654870	654870	654870	654870	-22815441	-1140772
CURRENT INCOME TAX	314338	314338	314338	314338	-22817806	-1140890
DEFERRED INCOME TAX	-861908	-861908	-861908	-861908	6	0
TOTAL INCOME TAXES	-547570	-547570	-547570	-547570	-22817800	-1140890
NET INCOME (BOOK)	-593202	-593202	-593202	-593202	2360	118
SOURCES OF FUNDS						
NET INCOME	-593202	-593202	-593202	-593202	2360	118
FINANCIAL DEPRECIATION	5933200	5933200	5933200	5933200	118664000	5933200
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-861908	-861908	-861908	-861908	6	0
NET ADDITIONS TO EQUITY	0	0	0	0	118664000	5933200
TOTAL SOURCES	4478090	4478090	4478090	4478090	237330366	11866518
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	118664000	5933200
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	118664000	5933200
NET CASH GENERATED DURING YEAR	4478090	4478090	4478090	4478090	118666366	5933318
CUMULATIVE NET CASH GENERATED	105232096	109710186	114188276	118666366	1476578256	73828913
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545145

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIC2 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO KENAI

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	8900	8900	8900	8900	8900	8900	8900
COST OF SERVICE ($/BBL)	8.430	8.430	8.430	8.430	8.430	8.430	8.430	8.430	8.430
TOTAL REVENUE	0	0	27384306	27384306	27384306	27384306	27384306	27384306	27384306
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	18300000	18300000	18300000	18300000	18300000	18300000	18300000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	11246700	11246700	11246700	11246700	11246700	11246700	11246700
TOTAL EXPENSES	0	0	29546700	29546700	29546700	29546700	29546700	29546700	29546700
INCOME BEFORE TAXES	0	0	-2162394	-2162394	-2162394	-2162394	-2162394	-2162394	-2162394
INVESTMENT TAX CREDIT	0	0	22493400	0	0	0	0	0	0
TAX DEPRECIATION	0	0	22493400	20244060	18219654	16397689	14757920	13282128	11953915
TAXABLE INCOME	0	0	-13409094	-11159754	-9135348	-7313383	-5673614	-4197822	-2869609
CURRENT INCOME TAX	0	0	-28929765	-5356682	-4384967	-3510424	-2723335	-2014955	-1377412
DEFERRED INCOME TAX	0	0	5398416	4318733	3347018	2472475	1685386	977006	339463
TOTAL INCOME TAXES	0	0	-23531349	-1037949	-1037949	-1037949	-1037949	-1037949	-1037949
NET INCOME (BOOK)	0	0	21368955	-1124445	-1124445	-1124445	-1124445	-1124445	-1124445
SOURCES OF FUNDS									
NET INCOME	0	0	21368955	-1124445	-1124445	-1124445	-1124445	-1124445	-1124445
FINANCIAL DEPRECIATION	0	0	11246700	11246700	11246700	11246700	11246700	11246700	11246700
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	5398416	4318733	3347018	2472475	1685386	977006	339463
NET ADDITIONS TO EQUITY	112467000	112467000	0	0	0	0	0	0	0
TOTAL SOURCES	112467000	112467000	38014071	14440988	13469273	12594730	11807641	11099261	10461718
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	112467000	112467000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	112467000	112467000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	38014071	14440988	13469273	12594730	11807641	11099261	10461718
CUMULATIVE NET CASH GENERATED	0	0	38014071	52455059	65924332	78519062	90326703	101425964	111887682
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545146

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIC2 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO KENAI

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	8900	8900	8900	8900	8900	8900	8900	8900	8900
COST OF SERVICE ($/BBL)	8.430	8.430	8.430	8.430	8.430	8.430	8.430	8.430	8.430
TOTAL REVENUE	27384306	27384306	27384306	27384306	27384306	27384306	27384306	27384306	27384306
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	18300000	18300000	18300000	18300000	18300000	18300000	18300000	18300000	18300000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	11246700	11246700	11246700	11246700	11246700	11246700	11246700	11246700	11246700
TOTAL EXPENSES	29546700	29546700	29546700	29546700	29546700	29546700	29546700	29546700	29546700
INCOME BEFORE TAXES	-2162394	-2162394	-2162394	-2162394	-2162394	-2162394	-2162394	-2162394	-2162394
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	10758523	9682671	8714404	7842964	7842964	7842964	7842964	7842964	7842964
TAXABLE INCOME	-1674217	-598365	369902	1241342	1241342	1241342	1241342	1241342	1241342
CURRENT INCOME TAX	-803625	-287215	177553	595844	595844	595844	595844	595844	595844
DEFERRED INCOME TAX	-234324	-750734	-1215502	-1633793	-1633793	-1633793	-1633793	-1633793	-1633793
TOTAL INCOME TAXES	-1037949	-1037949	-1037949	-1037949	-1037949	-1037949	-1037949	-1037949	-1037949
NET INCOME (BOOK)	-1124445	-1124445	-1124445	-1124445	-1124445	-1124445	-1124445	-1124445	-1124445
SOURCES OF FUNDS									
NET INCOME	-1124445	-1124445	-1124445	-1124445	-1124445	-1124445	-1124445	-1124445	-1124445
FINANCIAL DEPRECIATION	11246700	11246700	11246700	11246700	11246700	11246700	11246700	11246700	11246700
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-234324	-750734	-1215502	-1633793	-1633793	-1633793	-1633793	-1633793	-1633793
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	9887931	9371521	8906753	8488462	8488462	8488462	8488462	8488462	8488462
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	9887931	9371521	8906753	8488462	8488462	8488462	8488462	8488462	8488462
CUMULATIVE NET CASH GENERATED	121775613	131147134	140053887	148542349	157030811	165519273	174007735	182496197	190984659
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545147

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIC2 PROCESS 1/8 GAS AT PRUDHOE -EXTRACT PROPANE+ -LIQ PL TO KENAI

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	8900	8900	8900	8900	178000	8900
COST OF SERVICE ($/BBL)	8.430	8.430	8.430	8.430	185.450	9.273
TOTAL REVENUE	27384306	27384306	27384306	27384306	547686120	27384306
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	18300000	18300000	18300000	18300000	366000000	18300000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	11246700	11246700	11246700	11246700	224934000	11246700
TOTAL EXPENSES	29546700	29546700	29546700	29546700	590934000	29546700
INCOME BEFORE TAXES	-2162394	-2162394	-2162394	-2162394	-43247880	-2162394
INVESTMENT TAX CREDIT	0	0	0	0	22493400	1124670
TAX DEPRECIATION	7842964	7842964	7842964	7842964	224934004	11246700
TAXABLE INCOME	1241342	1241342	1241342	1241342	-43247884	-2162394
CURRENT INCOME TAX	595844	595844	595844	595844	-43252387	-2162619
DEFERRED INCOME TAX	-1633793	-1633793	-1633793	-1633793	7	0
TOTAL INCOME TAXES	-1037949	-1037949	-1037949	-1037949	-43252380	-2162619
NET INCOME (BOOK)	-1124445	-1124445	-1124445	-1124445	4500	225
SOURCES OF FUNDS						
NET INCOME	-1124445	-1124445	-1124445	-1124445	4500	225
FINANCIAL DEPRECIATION	11246700	11246700	11246700	11246700	224934000	11246700
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1633793	-1633793	-1633793	-1633793	7	0
NET ADDITIONS TO EQUITY	0	0	0	0	224934000	11246700
TOTAL SOURCES	8488462	8488462	8488462	8488462	449872507	22493625
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	224934000	11246700
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	224934000	11246700
NET CASH GENERATED DURING YEAR	8488462	8488462	8488462	8488462	224938507	11246925
CUMULATIVE NET CASH GENERATED	199473121	207961583	216450045	224938507	27798933787	139946689
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545148

CASE III

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIIB1 PROCESS 8/8 GAS AT FAIRBANKS -EXTRACT ETHANE+ -LIQ PL TO KENAI

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	155300	155300	155300	155300	155300	155300	155300
COST OF SERVICE ($/BBL)	.492	.492	.492	.492	.492	.492	.492	.492	.492
TOTAL REVENUE	0	0	27875560	27875560	27875560	27875560	27875560	27875560	27875560
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	15555000	15555000	15555000	15555000	15555000	15555000	15555000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	15253300	15253300	15253300	15253300	15253300	15253300	15253300
TOTAL EXPENSES	0	0	30808300	30808300	30808300	30808300	30808300	30808300	30808300
INCOME BEFORE TAXES	0	0	-2932740	-2932740	-2932740	-2932740	-2932740	-2932740	-2932740
INVESTMENT TAX CREDIT	0	0	30506600	0	0	0	0	0	0
TAX DEPRECIATION	0	0	30506600	27455940	24710346	22239311	20015380	18013842	16212458
TAXABLE INCOME	0	0	-18186040	-15135380	-12389786	-9918751	-7694820	-5693282	-3891898
CURRENT INCOME TAX	0	0	-39235899	-7264983	-5947097	-4761001	-3693514	-2732776	-1868111
DEFERRED INCOME TAX	0	0	7321584	5857268	4539382	3353286	2285799	1325061	460396
TOTAL INCOME TAXES	0	0	-31914315	-1407715	-1407715	-1407715	-1407715	-1407715	-1407715
NET INCOME (BOOK)	0	0	28981575	-1525025	-1525025	-1525025	-1525025	-1525025	-1525025
SOURCES OF FUNDS									
NET INCOME	0	0	28981575	-1525025	-1525025	-1525025	-1525025	-1525025	-1525025
FINANCIAL DEPRECIATION	0	0	15253300	15253300	15253300	15253300	15253300	15253300	15253300
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	7321584	5857268	4539382	3353286	2285799	1325061	460396
NET ADDITIONS TO EQUITY	152533000	152533000	0	0	0	0	0	0	0
TOTAL SOURCES	152533000	152533000	51556459	19585543	18267657	17081561	16014074	15053336	14188671
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	152533000	152533000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	152533000	152533000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	51556459	19585543	18267657	17081561	16014074	15053336	14188671
CUMULATIVE NET CASH GENERATED	0	0	51556459	71142002	89409659	106491220	122505294	137558630	151747301
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545150

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIIB1 PROCESS 8/8 GAS AT FAIRBANKS -EXTRACT ETHANE+ -LIQ PL TO KENAI

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	155300	155300	155300	155300	155300	155300	155300	155300	155300
COST OF SERVICE ($/BBL)	.492	.492	.492	.492	.492	.492	.492	.492	.492
TOTAL REVENUE	27875560	27875560	27875560	27875560	27875560	27875560	27875560	27875560	27875560
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	15555000	15555000	15555000	15555000	15555000	15555000	15555000	15555000	15555000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	15253300	15253300	15253300	15253300	15253300	15253300	15253300	15253300	15253300
TOTAL EXPENSES	30808300	30808300	30808300	30808300	30808300	30808300	30808300	30808300	30808300
INCOME BEFORE TAXES	-2932740	-2932740	-2932740	-2932740	-2932740	-2932740	-2932740	-2932740	-2932740
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	14591212	13132091	11818882	10636994	10636994	10636994	10636994	10636994	10636994
TAXABLE INCOME	-2270652	-811531	501678	1683566	1683566	1683566	1683566	1683566	1683566
CURRENT INCOME TAX	-1089913	-389535	240805	808112	808112	808112	808112	808112	808112
DEFERRED INCOME TAX	-317802	-1018180	-1648520	-2215827	-2215827	-2215827	-2215827	-2215827	-2215827
TOTAL INCOME TAXES	-1407715	-1407715	-1407715	-1407715	-1407715	-1407715	-1407715	-1407715	-1407715
NET INCOME (BOOK)	-1525025	-1525025	-1525025	-1525025	-1525025	-1525025	-1525025	-1525025	-1525025
SOURCES OF FUNDS									
NET INCOME	-1525025	-1525025	-1525025	-1525025	-1525025	-1525025	-1525025	-1525025	-1525025
FINANCIAL DEPRECIATION	15253300	15253300	15253300	15253300	15253300	15253300	15253300	15253300	15253300
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-317802	-1018180	-1648520	-2215827	-2215827	-2215827	-2215827	-2215827	-2215827
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	13410473	12710095	12079755	11512448	11512448	11512448	11512448	11512448	11512448
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	13410473	12710095	12079755	11512448	11512448	11512448	11512448	11512448	11512448
CUMULATIVE NET CASH GENERATED	165157774	177867869	189947624	201460072	212972520	224484968	235997416	247509864	259022312
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545151

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIIB1 PROCESS 8/8 GAS AT FAIRBANKS -EXTRACT ETHANE+ -LIQ PL TO KENAI

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	155300	155300	155300	155300	3106000	155300
COST OF SERVICE ($/BBL)	.492	.492	.492	.492	10.824	.541
TOTAL REVENUE	27875560	27875560	27875560	27875560	557511200	27875560
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	15555000	15555000	15555000	15555000	311100000	15555000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	15253300	15253300	15253300	15253300	305066000	15253300
TOTAL EXPENSES	30808300	30808300	30808300	30808300	616166000	30808300
INCOME BEFORE TAXES	-2932740	-2932740	-2932740	-2932740	-58654800	-2932740
INVESTMENT TAX CREDIT	0	0	0	0	30506600	1525330
TAX DEPRECIATION	10636994	10636994	10636994	10636994	305066002	15253300
TAXABLE INCOME	1683566	1683566	1683566	1683566	-58654802	-2932740
CURRENT INCOME TAX	808112	808112	808112	808112	-58660904	-2933045
DEFERRED INCOME TAX	-2215827	-2215827	-2215827	-2215827	4	0
TOTAL INCOME TAXES	-1407715	-1407715	-1407715	-1407715	-58660900	-2933045
NET INCOME (BOOK)	-1525025	-1525025	-1525025	-1525025	6100	305
SOURCES OF FUNDS						
NET INCOME	-1525025	-1525025	-1525025	-1525025	6100	305
FINANCIAL DEPRECIATION	15253300	15253300	15253300	15253300	305066000	15253300
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2215827	-2215827	-2215827	-2215827	4	0
NET ADDITIONS TO EQUITY	0	0	0	0	305066000	15253300
TOTAL SOURCES	11512448	11512448	11512448	11512448	610138104	30506905
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	305066000	15253300
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	305066000	15253300
NET CASH GENERATED DURING YEAR	11512448	11512448	11512448	11512448	305072104	15253605
CUMULATIVE NET CASH GENERATED	270534760	282047208	293559656	305072104	379044712	189802236
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545152

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 1118B2 PROCESS B/B GAS AT FAIRBANKS -EXTRACT PROPANE+ -LIQ PL TO KENAI

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	.857	.857	.857	.857	.857	.857	.857	.857	.857
TOTAL REVENUE	0	0	22155954	22155954	22155954	22155954	22155954	22155954	22155954
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	13100000	13100000	13100000	13100000	13100000	13100000	13100000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	11211600	11211600	11211600	11211600	11211600	11211600	11211600
TOTAL EXPENSES	0	0	24311600	24311600	24311600	24311600	24311600	24311600	24311600
INCOME BEFORE TAXES	0	0	-2155646	-2155646	-2155646	-2155646	-2155646	-2155646	-2155646
INVESTMENT TAX CREDIT	0	0	22423200	0	0	0	0	0	0
TAX DEPRECIATION	0	0	22423200	20180880	18162792	16346513	14711862	13240675	11916608
TAXABLE INCOME	0	0	-13367246	-11124926	-9106838	-7290559	-5655908	-4184721	-2860654
CURRENT INCOME TAX	0	0	-28839478	-5339964	-4371282	-3499468	-2714835	-2008666	-1373114
DEFERRED INCOME TAX	0	0	5381568	4305254	3336572	2464758	1680125	973956	338404
TOTAL INCOME TAXES	0	0	-23457910	-1034710	-1034710	-1034710	-1034710	-1034710	-1034710
NET INCOME (BOOK)	0	0	21302264	-1120936	-1120936	-1120936	-1120936	-1120936	-1120936
SOURCES OF FUNDS									
NET INCOME	0	0	21302264	-1120936	-1120936	-1120936	-1120936	-1120936	-1120936
FINANCIAL DEPRECIATION	0	0	11211600	11211600	11211600	11211600	11211600	11211600	11211600
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	5381568	4305254	3336572	2464758	1680125	973956	338404
NET ADDITIONS TO EQUITY	112116000	112116000	0	0	0	0	0	0	0
TOTAL SOURCES	112116000	112116000	37895432	14395918	13427236	12555422	11770789	11064620	10429068
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	112116000	112116000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	112116000	112116000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	37895432	14395918	13427236	12555422	11770789	11064620	10429068
CUMULATIVE NET CASH GENERATED	0	0	37895432	52291350	65718586	78274008	90044797	101109417	111538485
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545153

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIIB2 PROCESS 8/8 GAS AT FAIRBANKS -EXTRACT PROPANE+ -LIQ PL TO KENAI

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	70800	70800	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	.857	.857	.857	.857	.857	.857	.857	.857	.857
TOTAL REVENUE	22155954	22155954	22155954	22155954	22155954	22155954	22155954	22155954	22155954
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	13100000	13100000	13100000	13100000	13100000	13100000	13100000	13100000	13100000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	11211600	11211600	11211600	11211600	11211600	11211600	11211600	11211600	11211600
TOTAL EXPENSES	24311600	24311600	24311600	24311600	24311600	24311600	24311600	24311600	24311600
INCOME BEFORE TAXES	-2155646	-2155646	-2155646	-2155646	-2155646	-2155646	-2155646	-2155646	-2155646
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	10724947	9652452	8687207	7818486	7818486	7818486	7818486	7818486	7818486
TAXABLE INCOME	-1668993	-596498	368747	1237468	1237468	1237468	1237468	1237468	1237468
CURRENT INCOME TAX	-801117	-286319	176999	593985	593985	593985	593985	593985	593985
DEFERRED INCOME TAX	-233593	-748391	-1211709	-1628695	-1628695	-1628695	-1628695	-1628695	-1628695
TOTAL INCOME TAXES	-1034710	-1034710	-1034710	-1034710	-1034710	-1034710	-1034710	-1034710	-1034710
NET INCOME (BOOK)	-1120936	-1120936	-1120936	-1120936	-1120936	-1120936	-1120936	-1120936	-1120936
SOURCES OF FUNDS									
NET INCOME	-1120936	-1120936	-1120936	-1120936	-1120936	-1120936	-1120936	-1120936	-1120936
FINANCIAL DEPRECIATION	11211600	11211600	11211600	11211600	11211600	11211600	11211600	11211600	11211600
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-233593	-748391	-1211709	-1628695	-1628695	-1628695	-1628695	-1628695	-1628695
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	9857071	9342273	8878955	8461969	8461969	8461969	8461969	8461969	8461969
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	9857071	9342273	8878955	8461969	8461969	8461969	8461969	8461969	8461969
CUMULATIVE NET CASH GENERATED	121395556	130737829	139616784	148078753	156540722	165002691	173464660	181926629	190388598
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545154

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIIB2 PROCESS 8/8 GAS AT FAIRBANKS -EXTRACT PROPANE+ -LIQ PL TO KENAI

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	70800	70800	70800	70800	1416000	70800
COST OF SERVICE ($/BBL)	.857	.357	.857	.857	18.854	.943
TOTAL REVENUE	22155954	22155954	22155954	22155954	443119080	22155954
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	13100000	13100000	13100000	13100000	262000000	13100000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	11211600	11211600	11211600	11211600	224232000	11211600
TOTAL EXPENSES	24311600	24311600	24311600	24311600	486232000	24311600
INCOME BEFORE TAXES	-2155646	-2155646	-2155646	-2155646	-43112920	-2155646
INVESTMENT TAX CREDIT	0	0	0	0	22423200	1121160
TAX DEPRECIATION	7818486	7818486	7818486	7818486	224231996	11211600
TAXABLE INCOME	1237468	1237468	1237468	1237468	-43112916	-2155646
CURRENT INCOME TAX	593985	593985	593985	593985	-43117394	-2155870
DEFERRED INCOME TAX	-1628695	-1628695	-1628695	-1628695	-6	0
TOTAL INCOME TAXES	-1034710	-1034710	-1034710	-1034710	-43117400	-2155870
NET INCOME (BOOK)	-1120936	-1120936	-1120936	-1120936	4480	224
SOURCES OF FUNDS						
NET INCOME	-1120936	-1120936	-1120936	-1120936	4480	224
FINANCIAL DEPRECIATION	11211600	11211600	11211600	11211600	224232000	11211600
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1628695	-1628695	-1628695	-1628695	-6	0
NET ADDITIONS TO EQUITY	0	0	0	0	224232000	11211600
TOTAL SOURCES	8461969	8461969	8461969	8461969	448468474	22423424
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	224232000	11211600
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	224232000	11211600
NET CASH GENERATED DURING YEAR	8461969	8461969	8461969	8461969	224236474	11211824
CUMULATIVE NET CASH GENERATED	198850567	207312536	215774505	224236474	790198379	13950991
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545155

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIID PROCESS 8/8 GAS AT FAIRBANKS -EQ. GAS/C3+ BTU -LIQ PL TO KENAI

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	67600	67600	67600	67600	67600	67600	67600
COST OF SERVICE ($/BBL)	1.118	1.118	1.118	1.118	1.118	1.118	1.118	1.118	1.118
TOTAL REVENUE	0	0	27585095	27585095	27585095	27585095	27585095	27585095	27585095
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	15100000	15100000	15100000	15100000	15100000	15100000	15100000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	15457000	15457000	15457000	15457000	15457000	15457000	15457000
TOTAL EXPENSES	0	0	30557000	30557000	30557000	30557000	30557000	30557000	30557000
INCOME BEFORE TAXES	0	0	-2971905	-2971905	-2971905	-2971905	-2971905	-2971905	-2971905
INVESTMENT TAX CREDIT	0	0	30914000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	30914000	27822600	25040340	22536306	20282675	18254408	16428967
TAXABLE INCOME	0	0	-18428905	-15337505	-12555245	-10051211	-7797580	-5769313	-3943872
CURRENT INCOME TAX	0	0	-39759875	-7362003	-6026518	-4824582	-3742839	-2769270	-1893059
DEFERRED INCOME TAX	0	0	7419360	5935488	4600003	3398067	2316324	1342755	466544
TOTAL INCOME TAXES	0	0	-32340515	-1426515	-1426515	-1426515	-1426515	-1426515	-1426515
NET INCOME (BOOK)	0	0	29368610	-1545390	-1545390	-1545390	-1545390	-1545390	-1545390
SOURCES OF FUNDS									
NET INCOME	0	0	29368610	-1545390	-1545390	-1545390	-1545390	-1545390	-1545390
FINANCIAL DEPRECIATION	0	0	15457000	15457000	15457000	15457000	15457000	15457000	15457000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	7419360	5935488	4600003	3398067	2316324	1342755	466544
NET ADDITIONS TO EQUITY	154570000	154570000	0	0	0	0	0	0	0
TOTAL SOURCES	154570000	154570000	52244970	19847098	18511613	17309677	16227934	15254365	14378154
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	154570000	154570000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	154570000	154570000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	52244970	19847098	18511613	17309677	16227934	15254365	14378154
CUMULATIVE NET CASH GENERATED	0	0	52244970	72092068	90603681	107913358	124141292	139395657	153773811
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545156

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IIID PROCESS 8/8 GAS AT FAIRBANKS -EQ. GAS/C3+ BTU -LIQ PL TO KENAI

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (OBLS)	67600	67600	67600	67600	67600	67600	67600	67600	67600
COST OF SERVICE ($/BBL)	1.118	1.118	1.118	1.118	1.118	1.118	1.118	1.118	1.118
TOTAL REVENUE	27585095	27585095	27585095	27585095	27585095	27585095	27585095	27585095	27585095
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	15100000	15100000	15100000	15100000	15100000	15100000	15100000	15100000	15100000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	15457000	15457000	15457000	15457000	15457000	15457000	15457000	15457000	15457000
TOTAL EXPENSES	30557000	30557000	30557000	30557000	30557000	30557000	30557000	30557000	30557000
INCOME BEFORE TAXES	-2971905	-2971905	-2971905	-2971905	-2971905	-2971905	-2971905	-2971905	-2971905
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	14786070	13307463	11976717	10779045	10779045	10779045	10779045	10779045	10779045
TAXABLE INCOME	-2300975	-822368	508378	1706050	1706050	1706050	1706050	1706050	1706050
CURRENT INCOME TAX	-1104468	-394737	244021	818904	818904	818904	818904	818904	818904
DEFERRED INCOME TAX	-322047	-1031778	-1670536	-2245419	-2245419	-2245419	-2245419	-2245419	-2245419
TOTAL INCOME TAXES	-1426515	-1426515	-1426515	-1426515	-1426515	-1426515	-1426515	-1426515	-1426515
NET INCOME (BOOK)	-1545390	-1545390	-1545390	-1545390	-1545390	-1545390	-1545390	-1545390	-1545390
SOURCES OF FUNDS									
NET INCOME	-1545390	-1545390	-1545390	-1545390	-1545390	-1545390	-1545390	-1545390	-1545390
FINANCIAL DEPRECIATION	15457000	15457000	15457000	15457000	15457000	15457000	15457000	15457000	15457000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-322047	-1031778	-1670536	-2245419	-2245419	-2245419	-2245419	-2245419	-2245419
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	13589563	12879832	12241074	11666191	11666191	11666191	11666191	11666191	11666191
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	13589563	12879832	12241074	11666191	11666191	11666191	11666191	11666191	11666191
CUMULATIVE NET CASH GENERATED	167363374	180243206	192484280	204150471	215816662	227482853	239149044	250815235	262481426
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545157

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 1IID PROCESS 8/8 GAS AT FAIRBANKS -EQ. GAS/C3+ BTU -LIQ PL TO KENAI

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	67600	67500	67600	67600	1352000	67600
COST OF SERVICE ($/BBL)	1.118	1.118	1.118	1.118	24.596	1.230
TOTAL REVENUE	27585095	27585095	27585095	27585095	551701900	27585095
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	15100000	15100000	15100000	15100000	302000000	15100000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	15457000	15457000	15457000	15457000	309140000	15457000
TOTAL EXPENSES	30557000	30557000	30557000	30557000	611140000	30557000
INCOME BEFORE TAXES	-2971905	-2971905	-2971905	-2971905	-59438100	-2971905
INVESTMENT TAX CREDIT	0	0	0	0	30914000	1545700
TAX DEPRECIATION	10779045	10779045	10779045	10779045	309139996	15457000
TAXABLE INCOME	1706050	1706050	1706050	1706050	-59438096	-2971905
CURRENT INCOME TAX	818904	818904	818904	818904	-59444290	-2972215
DEFERRED INCOME TAX	-2245419	-2245419	-2245419	-2245419	-10	-1
TOTAL INCOME TAXES	-1426515	-1426515	-1426515	-1426515	-59444300	-2972215
NET INCOME (BOOK)	-1545390	-1545390	-1545390	-1545390	6200	310
SOURCES OF FUNDS						
NET INCOME	-1545390	-1545390	-1545390	-1545390	6200	310
FINANCIAL DEPRECIATION	15457000	15457000	15457000	15457000	309140000	15457000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2245419	-2245419	-2245419	-2245419	-10	-1
NET ADDITIONS TO EQUITY	0	0	0	0	309140000	15457000
TOTAL SOURCES	11666191	11666191	11666191	11666191	618286190	30914310
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	309140000	15457000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	309140000	15457000
NET CASH GENERATED DURING YEAR	11666191	11666191	11666191	11666191	309146190	15457310
CUMULATIVE NET CASH GENERATED	274147617	285813808	297479999	309146190	3846739002	192336950
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545158

CASE IV

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IVA1 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C2+ -USE OLD PL TO HAINES

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	2.733	2.733	2.733	2.733	2.733	2.733	2.733	2.733	2.733
TOTAL REVENUE	0	0	19350201	19350201	19350201	19350201	19350201	19350201	19350201
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	13520000	13520000	13520000	13520000	13520000	13520000	13520000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPPECIATION	0	0	7218000	7218000	7218000	7218000	7218000	7218000	7218000
TOTAL EXPENSES	0	0	20738000	20738000	20738000	20738000	20738000	20738000	20738000
INCOME BEFORE TAXES	0	0	-1387799	-1387799	-1387799	-1387799	-1387799	-1387799	-1387799
INVESTMENT TAX CREDIT	0	0	14436000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	14436000	12992400	11693150	10523844	9471460	8524314	7671882
TAXABLE INCOME	0	0	-8605799	-7162199	-5862959	-4693643	-3641259	-2694113	-1841681
CURRENT INCOME TAX	0	0	-18566784	-3437856	-2814220	-2252949	-1747804	-1293174	-884007
DEFERRED INCOME TAX	0	0	3464640	2771712	2148076	1586805	1081660	627030	217863
TOTAL INCOME TAXES	0	0	-15102144	-666144	-666144	-666144	-666144	-666144	-666144
NET INCOME (BOOK)	0	0	13714345	-721655	-721655	-721655	-721655	-721655	-721655
SOURCES OF FUNDS									
NET INCOME	0	0	13714345	-721655	-721655	-721655	-721655	-721655	-721655
FINANCIAL DEPRECIATION	0	0	7218000	7218000	7218000	7218000	7218000	7218000	7218000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	3464640	2771712	2148076	1586805	1081660	627030	217863
NET ADDITIONS TO EQUITY	72180000	72180000	0	0	0	0	0	0	0
TOTAL SOURCES	72180000	72180000	24396985	9268057	8644421	8083150	7578005	7123375	6714208
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	72180000	72180000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	72180000	72180000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	24396985	9268057	8644421	8083150	7578005	7123375	6714208
CUMULATIVE NET CASH GENERATED	0	0	24396985	33665042	42309463	50392613	57970618	65093993	71808201
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545160

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IVA1 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C2+ -USE OLD PL TO HAINES

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	19400	19400	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	2.733	2.733	2.733	2.733	2.733	2.733	2.733	2.733	2.733
TOTAL REVENUE	19350201	19350201	19350201	19350201	19350201	19350201	19350201	19350201	19350201
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	13520000	13520000	13520000	13520000	13520000	13520000	13520000	13520000	13520000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	7218000	7218000	7218000	7218000	7218000	7218000	7218000	7218000	7218000
TOTAL EXPENSES	20738000	20738000	20738000	20738000	20738000	20738000	20738000	20738000	20738000
INCOME BEFORE TAXES	-1387799	-1387799	-1387799	-1387799	-1387799	-1387799	-1387799	-1387799	-1387799
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	6904694	6214225	5592802	5033522	5033522	5033522	5033522	5033522	5033522
TAXABLE INCOME	-1074493	-384024	237399	796679	796679	796679	796679	796679	796679
CURRENT INCOME TAX	-515757	-184331	113951	382406	382406	382406	382406	382406	382406
DEFERRED INCOME TAX	-150387	-481813	-780095	-1048550	-1048550	-1048550	-1048550	-1048550	-1048550
TOTAL INCOME TAXES	-666144	-666144	-666144	-666144	-666144	-666144	-666144	-666144	-666144
NET INCOME (BOOK)	-721655	-721655	-721655	-721655	-721655	-721655	-721655	-721655	-721655
SOURCES OF FUNDS									
NET INCOME	-721655	-721655	-721655	-721655	-721655	-721655	-721655	-721655	-721655
FINANCIAL DEPRECIATION	7218000	7218000	7218000	7218000	7218000	7218000	7218000	7218000	7218000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-150387	-481813	-780095	-1048550	-1048550	-1048550	-1048550	-1048550	-1048550
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	6345958	6014532	5716250	5447795	5447795	5447795	5447795	5447795	5447795
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	6345958	6014532	5716250	5447795	5447795	5447795	5447795	5447795	5447795
CUMULATIVE NET CASH GENERATED	78154159	84168691	89884941	95332736	100780531	106228326	111676121	117123916	122571711
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545161

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IVA1 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C2+ -USE OLD PL TO HAINES

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	19400	19400	19400	19400	388000	19400
COST OF SERVICE ($/BBL)	2.733	2.733	2.733	2.733	60.126	3.006
TOTAL REVENUE	19350201	19350201	19350201	19350201	387004020	19350201
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	13520000	13520000	13520000	13520000	270400000	13520000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	7218000	7218000	7218000	7218000	144360000	7218000
TOTAL EXPENSES	20738000	20738000	20738000	20738000	414760000	20738000
INCOME BEFORE TAXES	-1387799	-1387799	-1387799	-1387799	-27755980	-1387799
INVESTMENT TAX CREDIT	0	0	0	0	14436000	721800
TAX DEPRECIATION	5033522	5033522	5033522	5033522	144360001	7218000
TAXABLE INCOME	796679	796679	796679	796679	-27755981	-1387799
CURRENT INCOME TAX	382406	382406	382406	382406	-27758871	-1387944
DEFERRED INCOME TAX	-1048550	-1048550	-1048550	-1048550	-9	0
TOTAL INCOME TAXES	-666144	-666144	-666144	-666144	-27758880	-1387944
NET INCOME (BOOK)	-721655	-721655	-721655	-721655	2900	145
SOURCES OF FUNDS						
NET INCOME	-721655	-721655	-721655	-721655	2900	145
FINANCIAL DEPRECIATION	7218000	7218000	7218000	7218000	144360000	7218000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1048550	-1048550	-1048550	-1048550	-9	0
NET ADDITIONS TO EQUITY	0	0	0	0	144360000	7218000
TOTAL SOURCES	5447795	5447795	5447795	5447795	288722891	14436145
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	144360000	7218000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	144360000	7218000
NET CASH GENERATED DURING YEAR	5447795	5447795	5447795	5447795	144362891	7218145
CUMULATIVE NET CASH GENERATED	128019506	133467301	138915096	144362891	1794322891	89816142
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545162

EARNINGS AND CASH FLOW PROJECTION CASE L

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IVA2 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C2+ -NEW PL TO HAINES

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	2.966	2.966	2.966	2.966	2.966	2.966	2.966	2.966	2.966
TOTAL REVENUE	0	0	21003864	21003864	21003864	21003864	21003864	21003864	21003864
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	11740000	11740000	11740000	11740000	11740000	11740000	11740000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	11469000	11469000	11469000	11469000	11469000	11469000	11469000
TOTAL EXPENSES	0	0	23209000	23209000	23209000	23209000	23209000	23209000	23209000
INCOME BEFORE TAXES	0	0	-2205136	-2205136	-2205136	-2205136	-2205136	-2205136	-2205136
INVESTMENT TAX CREDIT	0	0	22938000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	22938000	20644200	18579780	16721802	15049622	13544660	12190194
TAXABLE INCOME	0	0	-13674136	-11380336	-9315916	-7457938	-5785758	-4280796	-2926330
CURRENT INCOME TAX	0	0	-29501585	-5462561	-4471640	-3579810	-2777164	-2054782	-1404638
DEFERRED INCOME TAX	0	0	5505120	4404096	3413175	2521345	1718699	996317	346173
TOTAL INCOME TAXES	0	0	-23996465	-1058465	-1058465	-1058465	-1058465	-1058465	-1058465
NET INCOME (BOOK)	0	0	21791329	-1146671	-1146671	-1146671	-1146671	-1146671	-1146671
SOURCES OF FUNDS									
NET INCOME	0	0	21791329	-1146671	-1146671	-1146671	-1146671	-1146671	-1146671
FINANCIAL DEPRECIATION	0	0	11469000	11469000	11469000	11469000	11469000	11469000	11469000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	5505120	4404096	3413175	2521345	1718699	996317	346173
NET ADDITIONS TO EQUITY	114690000	114690000	0	0	0	0	0	0	0
TOTAL SOURCES	114690000	114690000	38765449	14726425	13735504	12843674	12041028	11318646	10668502
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	114690000	114690000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	114690000	114690000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	38765449	14726425	13735504	12843674	12041028	11318646	10668502
CUMULATIVE NET CASH GENERATED	0	0	38765449	53491874	67227378	80071052	92112080	103430726	114099228
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545163

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IVA2 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C2+ -NEW PL TO HAINES

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	19400	19400	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	2.966	2.966	2.966	2.966	2.966	2.966	2.966	2.966	2.966
TOTAL REVENUE	21003864	21003864	21003864	21003864	21003864	21003864	21003864	21003864	21003864
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	11740000	11740000	11740000	11740000	11740000	11740000	11740000	11740000	11740000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	11469000	11469000	11469000	11469000	11469000	11469000	11469000	11469000	11469000
TOTAL EXPENSES	23209000	23209000	23209000	23209000	23209000	23209000	23209000	23209000	23209000
INCOME BEFORE TAXES	-2205136	-2205136	-2205136	-2205136	-2205136	-2205136	-2205136	-2205136	-2205136
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	10971179	9874057	8886651	7997986	7997986	7997986	7997986	7997986	7997986
TAXABLE INCOME	-1707310	-610193	377213	1265878	1265878	1265878	1265878	1265878	1265878
CURRENT INCOME TAX	-819509	-292892	181062	607622	607622	607622	607622	607622	607622
DEFERRED INCOME TAX	-238956	-765573	-1239527	-1666087	-1666087	-1666087	-1666087	-1666087	-1666087
TOTAL INCOME TAXES	-1058465	-1058465	-1058465	-1058465	-1058465	-1058465	-1058465	-1058465	-1058465
NET INCOME (BOOK)	-1146671	-1146671	-1146671	-1146671	-1146671	-1146671	-1146671	-1146671	-1146671
SOURCES OF FUNDS									
NET INCOME	-1146671	-1146671	-1146671	-1146671	-1146671	-1146671	-1146671	-1146671	-1146671
FINANCIAL DEPRECIATION	11469000	11469000	11469000	11469000	11469000	11469000	11469000	11469000	11469000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-238956	-765573	-1239527	-1666087	-1666087	-1666087	-1666087	-1666087	-1666087
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	10083373	9556756	9082802	8656242	8656242	8656242	8656242	8656242	8656242
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	10083373	9556756	9082802	8656242	8656242	8656242	8656242	8656242	8656242
CUMULATIVE NET CASH GENERATED	124182601	133739357	142822159	151478401	160134643	168790885	177447127	186103369	194759611
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545164

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IVA2 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C2+ -NEW PL TO HAINES

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	19400	19400	19400	19400	388000	19400
COST OF SERVICE ($/BBL)	2.966	2.966	2.966	2.966	65.252	3.263
TOTAL REVENUE	21003864	21003864	21003864	21003864	420077280	21003864
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	11740000	11740000	11740000	11740000	234800000	11740000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	11469000	11469000	11469000	11469000	229380000	11469000
TOTAL EXPENSES	23209000	23209000	23209000	23209000	464180000	23209000
INCOME BEFORE TAXES	-2205136	-2205136	-2205136	-2205136	-44102720	-2205136
INVESTMENT TAX CREDIT	0	0	0	0	22938000	1146900
TAX DEPRECIATION	7997985	7997985	7997986	7997986	229380000	11469000
TAXABLE INCOME	1265878	1265878	1265878	1265878	-44102720	-2205136
CURRENT INCOME TAX	607622	607622	607622	607622	-44107299	-2205365
DEFERRED INCOME TAX	-1666087	-1666087	-1666087	-1666087	-1	0
TOTAL INCOME TAXES	-1058465	-1058465	-1058465	-1058465	-44107300	-2205365
NET INCOME (BOOK)	-1146671	-1146671	-1146671	-1146671	4580	229
SOURCES OF FUNDS						
NET INCOME	-1146671	-1146671	-1146671	-1146671	4580	229
FINANCIAL DEPRECIATION	11469000	11469000	11469000	11469000	229380000	11469000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1666087	-1666087	-1666087	-1666087	-1	0
NET ADDITIONS TO EQUITY	0	0	0	0	229380000	11469000
TOTAL SOURCES	8656242	8656242	8656242	8656242	458764579	22938229
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	229380000	11469000
LONG TERM DEPT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	229380000	11469000
NET CASH GENERATED DURING YEAR	8656242	8656242	8656242	8656242	229384579	11469229
CUMULATIVE NET CASH GENERATED	203415853	212072095	220728337	229384579	28542564804	142712840
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545165

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IVB1 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C2+ -LIQ PL TO KENAI

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	2.097	2.097	2.097	2.097	2.097	2.097	2.097	2.097	2.097
TOTAL REVENUE	0	0	14847772	14847772	14847772	14847772	14847772	14847772	14847772
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	9380000	9380000	9380000	9380000	9380000	9380000	9380000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	6769300	6769300	6769300	6769300	6769300	6769300	6769300
TOTAL EXPENSES	0	0	16149300	16149300	16149300	16149300	16149300	16149300	16149300
INCOME BEFORE TAXES	0	0	-1301528	-1301528	-1301528	-1301528	-1301528	-1301528	-1301528
INVESTMENT TAX CREDIT	0	0	13538600	0	0	0	0	0	0
TAX DEPRECIATION	0	0	13538600	12184740	10966266	9869639	8882675	7994408	7194967
TAXABLE INCOME	0	0	-8070828	-6716968	-5498494	-4401867	-3414903	-2526636	-1727195
CURRENT INCOME TAX	0	0	-17412597	-3224145	-2639277	-2112896	-1639154	-1212785	-829054
DEFERRED INCOME TAX	0	0	3249264	2599412	2014544	1488163	1014421	588052	204321
TOTAL INCOME TAXES	0	0	-14163333	-624733	-624733	-624733	-624733	-624733	-624733
NET INCOME (BOOK)	0	0	12861805	-676795	-676795	-676795	-676795	-676795	-676795
SOURCES OF FUNDS									
NET INCOME	0	0	12861805	-676795	-676795	-676795	-676795	-676795	-676795
FINANCIAL DEPRECIATION	0	0	6769300	6769300	6769300	6769300	6769300	6769300	6769300
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	3249264	2599412	2014544	1488163	1014421	588052	204321
NET ADDITIONS TO EQUITY	67693000	67693000	0	0	0	0	0	0	0
TOTAL SOURCES	67693000	67693000	22880369	8691917	8107049	7580668	7106926	6680557	6296826
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	67693000	67693000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	67693000	67693000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	22880369	8691917	8107049	7580668	7106926	6680557	6296826
CUMULATIVE NET CASH GENERATED	0	0	22880369	31572286	39679335	47260003	54366929	61047486	67344312
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545166

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IVB1 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C2+ -LIQ PL TO KENAI

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	19400	19400	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	2.097	2.097	2.097	2.097	2.097	2.097	2.097	2.097	2.097
TOTAL REVENUE	14847772	14847772	14847772	14847772	14847772	14847772	14847772	14847772	14847772
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	9380000	9380000	9380000	9380000	9380000	9380000	9380000	9380000	9380000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	6769300	6769300	6769300	6769300	6769300	6769300	6769300	6769300	6769300
TOTAL EXPENSES	16149300	16149300	16149300	16149300	16149300	16149300	16149300	16149300	16149300
INCOME BEFORE TAXES	-1301528	-1301528	-1301528	-1301528	-1301528	-1301528	-1301528	-1301528	-1301528
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	6475470	5827923	5245131	4720618	4720618	4720618	4720618	4720618	4720618
TAXABLE INCOME	-1007698	-360151	222641	747154	747154	747154	747154	747154	747154
CURRENT INCOME TAX	-483695	-172873	106868	358634	358634	358634	358634	358634	358634
DEFERRED INCOME TAX	-141038	-451860	-731601	-983367	-983367	-983367	-983367	-983367	-983367
TOTAL INCOME TAXES	-624733	-624733	-624733	-624733	-624733	-624733	-624733	-624733	-624733
NET INCOME (BOOK)	-676795	-676795	-676795	-676795	-676795	-676795	-676795	-676795	-676795
SOURCES OF FUNDS									
NET INCOME	-676795	-676795	-676795	-676795	-676795	-676795	-676795	-676795	-676795
FINANCIAL DEPRECIATION	6769300	6769300	6769300	6769300	6769300	6769300	6769300	6769300	6769300
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-141038	-451860	-731601	-983367	-983367	-983367	-983367	-983367	-983367
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	5951467	5640645	5360904	5109138	5109138	5109138	5109138	5109138	5109138
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	5951467	5640645	5360904	5109138	5109138	5109138	5109138	5109138	5109138
CUMULATIVE NET CASH GENERATED	73295779	78936424	84297328	89406466	94515604	99624742	104733880	109843018	114952156
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545167

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IVB1 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C2+ -LIQ PL TO KENAI

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	19400	19400	19400	19400	388000	19400
COST OF SERVICE ($/BBL)	2.097	2.097	2.097	2.097	46.134	2.307
TOTAL REVENUE	14847772	14847772	14847772	14847772	296955440	14847772
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	9380000	9380000	9380000	9380000	187600000	9380000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	6769300	6769300	6769300	6769300	135386000	6769300
TOTAL EXPENSES	16149300	16149300	16149300	16149300	322986000	16149300
INCOME BEFORE TAXES	-1301528	-1301528	-1301528	-1301528	-26030560	-1301528
INVESTMENT TAX CREDIT	0	0	0	0	13538600	676930
TAX DEPRECIATION	4720618	4720618	4720618	4720618	135385999	6769300
TAXABLE INCOME	747154	747154	747154	747154	-26030559	-1301528
CURRENT INCOME TAX	358634	358634	358634	358634	-26033268	-1301663
DEFERRED INCOME TAX	-983367	-983367	-983367	-983367	8	0
TOTAL INCOME TAXES	-624733	-624733	-624733	-624733	-26033260	-1301663
NET INCOME (BOOK)	-676795	-676795	-676795	-676795	2700	135
SOURCES OF FUNDS						
NET INCOME	-676795	-676795	-676795	-676795	2700	135
FINANCIAL DEPRECIATION	6769300	6769300	6769300	6769300	135386000	6769300
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-983367	-983367	-983367	-983367	8	0
NET ADDITIONS TO EQUITY	0	0	0	0	135386000	6769300
TOTAL SOURCES	5109138	5109138	5109138	5109138	270774708	13538735
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	135386000	6769300
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	135386000	6769300
NET CASH GENERATED DURING YEAR	5109138	5109138	5109138	5109138	135388708	6769435
CUMULATIVE NET CASH GENERATED	120061294	125170432	130279570	135388708	1684656121	84232806
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545168

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IV32 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C3+ -LIQ PL TO KENAI

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	8900	8900	8900	8900	8900	8900	8900
COST OF SERVICE ($/BBL)	3.987	3.987	3.987	3.987	3.987	3.987	3.987	3.987	3.987
TOTAL REVENUE	0	0	12951958	12951958	12951958	12951958	12951958	12951958	12951958
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	8660000	8660000	8660000	8660000	8660000	8660000	8660000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	5313600	5313600	5313600	5313600	5313600	5313600	5313600
TOTAL EXPENSES	0	0	13973600	13973600	13973600	13973600	13973600	13973600	13973600
INCOME BEFORE TAXES	0	0	-1021642	-1021642	-1021642	-1021642	-1021642	-1021642	-1021642
INVESTMENT TAX CREDIT	0	0	10627200	0	0	0	0	0	0
TAX DEPRECIATION	0	0	10627200	9564480	8608032	7747229	6972506	6275255	5647730
TAXABLE INCOME	0	0	-6335242	-5272522	-4316074	-3455271	-2680548	-1983297	-1355772
CURRENT INCOME TAX	0	0	-13668116	-2530810	-2071715	-1658530	-1286663	-951983	-650770
DEFERRED INCOME TAX	0	0	2550528	2040422	1581327	1168142	796275	461595	160382
TOTAL INCOME TAXES	0	0	-11117588	-490388	-490388	-490388	-490388	-490388	-490388
NET INCOME (BOOK)	0	0	10095946	-531254	-531254	-531254	-531254	-531254	-531254
SOURCES OF FUNDS									
NET INCOME	0	0	10095946	-531254	-531254	-531254	-531254	-531254	-531254
FINANCIAL DEPRECIATION	0	0	5313600	5313600	5313600	5313600	5313600	5313600	5313600
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	2550528	2040422	1581327	1168142	796275	461595	160382
NET ADDITIONS TO EQUITY	53136000	53136000	0	0	0	0	0	0	0
TOTAL SOURCES	53136000	53136000	17960074	6822768	6363673	5950488	5578621	5243941	4942728
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	53136000	53136000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	53136000	53136000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	17960074	6822768	6363673	5950488	5578621	5243941	4942728
CUMULATIVE NET CASH GENERATED	0	0	17960074	24782842	31146515	37097003	42675624	47919565	52862293
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545169

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IVB2 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C3+ -LIQ PL TO KENAI

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	8900	8900	8900	8900	8900	8900	8900	8900	8900
COST OF SERVICE ($/BBL)	3.987	3.987	3.987	3.987	3.987	3.987	3.987	3.987	3.987
TOTAL REVENUE	12951958	12951958	12951958	12951958	12951958	12951958	12951958	12951958	12951958
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	8660000	8660000	8660000	8660000	8660000	8660000	8660000	8660000	8660000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	5313600	5313600	5313600	5313600	5313600	5313600	5313600	5313600	5313600
TOTAL EXPENSES	13973600	13973600	13973600	13973600	13973600	13973600	13973600	13973600	13973600
INCOME BEFORE TAXES	-1021642	-1021642	-1021642	-1021642	-1021642	-1021642	-1021642	-1021642	-1021642
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	5082957	4574661	4117195	3705476	3705476	3705476	3705476	3705476	3705476
TAXABLE INCOME	-790999	-282703	174763	586482	586482	586482	586482	586482	586482
CURRENT INCOME TAX	-379679	-135697	83886	281512	281512	281512	281512	281512	281512
DEFERRED INCOME TAX	-110709	-354691	-574274	-771900	-771900	-771900	-771900	-771900	-771900
TOTAL INCOME TAXES	-490388	-490388	-490388	-490388	-490388	-490388	-490388	-490388	-490388
NET INCOME (BOOK)	-531254	-531254	-531254	-531254	-531254	-531254	-531254	-531254	-531254
SOURCES OF FUNDS									
NET INCOME	-531254	-531254	-531254	-531254	-531254	-531254	-531254	-531254	-531254
FINANCIAL DEPRECIATION	5313600	5313600	5313600	5313600	5313600	5313600	5313600	5313600	5313600
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-110709	-354691	-574274	-771900	-771900	-771900	-771900	-771900	-771900
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	4671637	4427655	4208072	4010446	4010446	4010446	4010446	4010446	4010446
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	4671637	4427655	4208072	4010446	4010446	4010446	4010446	4010446	4010446
CUMULATIVE NET CASH GENERATED	57533930	61961585	66169657	70180103	74190549	78200995	82211441	86221887	90232333
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545170

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE 1V82 PROCESS 1/8 GAS AT FAIRBANKS -EXTRACT C3+ -LIQ PL TO KENAI

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	8900	8900	8900	8900	178000	8900
COST OF SERVICE ($/BBL)	3.987	3.987	3.987	3.987	87.719	4.386
TOTAL REVENUE	12951958	12951958	12951958	12951958	259039160	12951958
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	8660000	8660000	8660000	8660000	173200000	8660000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	5313600	5313600	5313600	5313600	106272000	5313600
TOTAL EXPENSES	13973600	13973600	13973600	13973600	279472000	13973600
INCOME BEFORE TAXES	-1021642	-1021642	-1021642	-1021642	-20432840	-1021642
INVESTMENT TAX CREDIT	0	0	0	0	10627200	531360
TAX DEPRECIATION	3705476	3705476	3705476	3705476	106272005	5313600
TAXABLE INCOME	586482	586482	586482	586482	-20432845	-1021642
CURRENT INCOME TAX	281512	281512	281512	281512	-20434957	-1021748
DEFERRED INCOME TAX	-771900	-771900	-771900	-771900	-3	0
TOTAL INCOME TAXES	-490388	-490388	-490388	-490388	-20434960	-1021748
NET INCOME (BOOK)	-531254	-531254	-531254	-531254	2120	106
SOURCES OF FUNDS						
NET INCOME	-531254	-531254	-531254	-531254	2120	106
FINANCIAL DEPRECIATION	5313600	5313600	5313600	5313600	106272000	5313600
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-771900	-771900	-771900	-771900	-3	0
NET ADDITIONS TO EQUITY	0	0	0	0	106272000	5313600
TOTAL SOURCES	4010446	4010446	4010446	4010446	212546117	10627306
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	106272000	5313600
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	106272000	5313600
NET CASH GENERATED DURING YEAR	4010446	4010446	4010446	4010446	106274117	5313706
CUMULATIVE NET CASH GENERATED	94242779	98253225	102263671	106274117	1322380188	66119009
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545171

CASE V

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VA1 PROCESS 1/8 GAS AT KENAI -EXTRACT ETHANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	4600	4600	4600	4600	4600	4600	4600
COST OF SERVICE ($/BBL)	6.965	6.965	6.965	6.965	6.965	6.965	6.965	6.965	6.965
TOTAL REVENUE	0	0	11693516	11693516	11693516	11693516	11693516	11693516	11693516
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	8200000	8200000	8200000	8200000	8200000	8200000	8200000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	4325100	4325100	4325100	4325100	4325100	4325100	4325100
TOTAL EXPENSES	0	0	12525100	12525100	12525100	12525100	12525100	12525100	12525100
INCOME BEFORE TAXES	0	0	-831584	-831584	-831584	-831584	-831584	-831584	-831584
INVESTMENT TAX CREDIT	0	0	8650200	0	0	0	0	0	0
TAX DEPRECIATION	0	0	8650200	7785180	7006662	6305996	5675396	5107857	4597071
TAXABLE INCOME	0	0	-5156684	-4291664	-3513146	-2812480	-2181880	-1614341	-1103555
CURRENT INCOME TAX	0	0	-1112540R	-2059999	-1686310	-1349990	-1047302	-774883	-529706
DEFERRED INCOME TAX	0	0	2076048	1660839	1287150	950830	648142	375723	130546
TOTAL INCOME TAXES	0	0	-9049360	-399160	-399160	-399160	-399160	-399160	-399160
NET INCOME (BOOK)	0	0	8217776	-432424	-432424	-432424	-432424	-432424	-432424
SOURCES OF FUNDS									
NET INCOME	0	0	8217776	-432424	-432424	-432424	-432424	-432424	-432424
FINANCIAL DEPRECIATION	0	0	4325100	4325100	4325100	4325100	4325100	4325100	4325100
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	2076048	1660839	1287150	950830	648142	375723	130546
NET ADDITIONS TO EQUITY	43251000	43251000	0	0	0	0	0	0	0
TOTAL SOURCES	43251000	43251000	14618924	5553515	5179826	4843506	4540818	4268399	4023222
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	43251000	43251000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	43251000	43251000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	14618924	5553515	5179826	4843506	4540818	4268399	4023222
CUMULATIVE NET CASH GENERATED	0	0	14618924	20172439	25352265	30195771	34736589	39004988	43028210
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545173

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VA1 PROCESS 1/8 GAS AT KENAI -EXTRACT ETHANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	4600	4600	4600	4600	4600	4600	4600	4600	4600
COST OF SERVICE ($/BBL)	6.965	6.965	6.965	6.965	6.965	6.965	6.965	6.965	6.965
TOTAL REVENUE	11693516	11693516	11693516	11693516	11693516	11693516	11693516	11693516	11693516
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	8200000	8200000	8200000	8200000	8200000	8200000	8200000	8200000	8200000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	4325100	4325100	4325100	4325100	4325100	4325100	4325100	4325100	4325100
TOTAL EXPENSES	12525100	12525100	12525100	12525100	12525100	12525100	12525100	12525100	12525100
INCOME BEFORE TAXES	-831584	-831584	-831584	-831584	-831584	-831584	-831584	-831584	-831584
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	4137364	3723627	3351265	3016138	3016138	3016138	3016138	3016138	3016138
TAXABLE INCOME	-643848	-230111	142251	477378	477378	477378	477378	477378	477378
CURRENT INCOME TAX	-309047	-110453	68281	229141	229141	229141	229141	229141	229141
DEFERRED INCOME TAX	-90113	-288707	-467441	-628301	-628301	-628301	-628301	-628301	-628301
TOTAL INCOME TAXES	-399160	-399160	-399160	-399160	-399160	-399160	-399160	-399160	-399160
NET INCOME (BOOK)	-432424	-432424	-432424	-432424	-432424	-432424	-432424	-432424	-432424
SOURCES OF FUNDS									
NET INCOME	-432424	-432424	-432424	-432424	-432424	-432424	-432424	-432424	-432424
FINANCIAL DEPRECIATION	4325100	4325100	4325100	4325100	4325100	4325100	4325100	4325100	4325100
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-90113	-288707	-467441	-628301	-628301	-628301	-628301	-628301	-628301
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	3802563	3603969	3425235	3264375	3264375	3264375	3264375	3264375	3264375
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	3802563	3603969	3425235	3264375	3264375	3264375	3264375	3264375	3264375
CUMULATIVE NET CASH GENERATED	46830773	50434742	53859977	57124352	60388727	63653102	66917477	70181852	73446227
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545174

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VA1 PROCESS 1/8 GAS AT KENAI -EXTRACT ETHANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	4600	4600	4600	4600	92000	4600
COST OF SERVICE ($/BBL)	6.965	6.965	6.965	6.965	153.230	7.662
TOTAL REVENUE	11693516	11693516	11693516	11693516	233870320	11693516
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	8200000	8200000	8200000	8200000	164000000	8200000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	4325100	4325100	4325100	4325100	86502000	4325100
TOTAL EXPENSES	12525100	12525100	12525100	12525100	250502000	12525100
INCOME BEFORE TAXES	-831584	-831584	-831584	-831584	-16631680	-831584
INVESTMENT TAX CREDIT	0	0	0	0	8650200	432510
TAX DEPRECIATION	3016138	3016138	3016138	3016138	86501998	4325100
TAXABLE INCOME	477378	477378	477378	477378	-16631678	-831584
CURRENT INCOME TAX	229141	229141	229141	229141	-16633407	-831670
DEFERRED INCOME TAX	-628301	-628301	-628301	-628301	7	0
TOTAL INCOME TAXES	-399160	-399160	-399160	-399160	-16633400	-831670
NET INCOME (BOOK)	-432424	-432424	-432424	-432424	1720	86
SOURCES OF FUNDS						
NET INCOME	-432424	-432424	-432424	-432424	1720	86
FINANCIAL DEPRECIATION	4325100	4325100	4325100	4325100	86502000	4325100
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-628301	-628301	-628301	-628301	7	0
NET ADDITIONS TO EQUITY	0	0	0	0	86502000	4325100
TOTAL SOURCES	3264375	3264375	3264375	3264375	173005727	8650286
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	86502000	4325100
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	86502000	4325100
NET CASH GENERATED DURING YEAR	3264375	3264375	3264375	3264375	86503727	4325186
CUMULATIVE NET CASH GENERATED	76710602	79974977	83239352	86503727	76375073	53819754
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545175

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VA2 PROCESS 1/8 GAS AT KENAI -EXTRACT PROPANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	1800	1800	1800	1800	1800	1800	1800
COST OF SERVICE ($/BBL)	14.685	14.685	14.685	14.685	14.685	14.685	14.685	14.685	14.685
TOTAL REVENUE	0	0	9647844	9647844	9647844	9647844	9647844	9647844	9647844
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	6630000	6630000	6630000	6630000	6630000	6630000	6630000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	3736200	3736200	3736200	3736200	3736200	3736200	3736200
TOTAL EXPENSES	0	0	10366200	10366200	10366200	10366200	10366200	10366200	10366200
INCOME BEFORE TAXES	0	0	-718356	-718356	-718356	-718356	-718356	-718356	-718356
INVESTMENT TAX CREDIT	0	0	7472400	0	0	0	0	0	0
TAX DEPRECIATION	0	0	7472400	6725160	6052644	5447380	4902642	4412377	3971140
TAXABLE INCOME	0	0	-4454556	-3707316	-3034800	-2429536	-1884798	-1394533	-953296
CURRENT INCOME TAX	0	0	-9610587	-1779512	-1456704	-1166177	-904703	-669376	-457582
DEFERRED INCOME TAX	0	0	1793376	1434701	1111893	821366	559892	324565	112771
TOTAL INCOME TAXES	0	0	-7817211	-344811	-344811	-344811	-344811	-344811	-344811
NET INCOME (BOOK)	0	0	7098855	-373545	-373545	-373545	-373545	-373545	-373545
SOURCES OF FUNDS									
NET INCOME	0	0	7098855	-373545	-373545	-373545	-373545	-373545	-373545
FINANCIAL DEPRECIATION	0	0	3736200	3736200	3736200	3736200	3736200	3736200	3736200
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	1793376	1434701	1111893	821366	559892	324565	112771
NET ADDITIONS TO EQUITY	37362000	37362000	0	0	0	0	0	0	0
TOTAL SOURCES	37362000	37362000	12628431	4797356	4474548	4184021	3922547	3687220	3475426
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	37362000	37362000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	37362000	37362000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	12628431	4797356	4474548	4184021	3922547	3687220	3475426
CUMULATIVE NET CASH GENERATED	0	0	12628431	17425787	21900335	26084356	30006903	33694123	37169549
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545176

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VA2 PROCESS 1/8 GAS AT KENAI -EXTRACT PROPANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	1800	1800	1800	1800	1800	1800	1800	1800	1800
COST OF SERVICE ($/BBL)	14.685	14.685	14.685	14.685	14.685	14.685	14.685	14.685	14.685
TOTAL REVENUE	9647844	9647844	9647844	9647844	9647844	9647844	9647844	9647844	9647844
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	6630000	6630000	6630000	6630000	6630000	6630000	6630000	6630000	6630000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	3736200	3736200	3736200	3736200	3736200	3736200	3736200	3736200	3736200
TOTAL EXPENSES	10366200	10366200	10366200	10366200	10366200	10366200	10366200	10366200	10366200
INCOME BEFORE TAXES	-718356	-718356	-718356	-718356	-718356	-718356	-718356	-718356	-718356
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	3574026	3216523	2894961	2605465	2605465	2605465	2605465	2605465	2605465
TAXABLE INCOME	-556182	-198679	122883	412379	412379	412379	412379	412379	412379
CURRENT INCOME TAX	-266967	-95414	58984	197942	197942	197942	197942	197942	197942
DEFERRED INCOME TAX	-77844	-249397	-403795	-542753	-542753	-542753	-542753	-542753	-542753
TOTAL INCOME TAXES	-344811	-344811	-344811	-344811	-344811	-344811	-344811	-344811	-344811
NET INCOME (BOOK)	-373545	-373545	-373545	-373545	-373545	-373545	-373545	-373545	-373545
SOURCES OF FUNDS									
NET INCOME	-373545	-373545	-373545	-373545	-373545	-373545	-373545	-373545	-373545
FINANCIAL DEPRECIATION	3736200	3736200	3736200	3736200	3736200	3736200	3736200	3736200	3736200
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-77844	-249397	-403795	-542753	-542753	-542753	-542753	-542753	-542753
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	3284811	3113258	2958860	2819902	2819902	2819902	2819902	2819902	2819902
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	3284811	3113258	2958860	2819902	2819902	2819902	2819902	2819902	2819902
CUMULATIVE NET CASH GENERATED	40454360	43567618	46526478	49346380	52166282	54986184	57806086	60625988	63445890
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545177

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VA2 PROCESS 1/8 GAS AT KENAI -EXTRACT PROPANE+ -LIQ PL TO FAIRBANKS

TIME PERIOD	1999	2000	2001	2002	9999	8988
DAILY TRANSPORTATION VOLUME (BBLS)	1800	1800	1800	1800	36000	1800
COST OF SERVICE ($/BBL)	14.685	14.685	14.685	14.685	323.070	16.154
TOTAL REVENUE	9647844	9647844	9647844	9647844	192956880	9647844
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	6630000	6630000	6630000	6630000	132600000	6630000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	3736200	3736200	3736200	3736200	74724000	3736200
TOTAL EXPENSES	10366200	10366200	10366200	10366200	207324000	10366200
INCOME BEFORE TAXES	-718356	-718356	-718356	-718356	-14367120	-718356
INVESTMENT TAX CREDIT	0	0	0	0	7472400	373620
TAX DEPRECIATION	2605465	2605465	2605465	2605465	74724003	3736200
TAXABLE INCOME	412379	412379	412379	412379	-14367123	-718356
CURRENT INCOME TAX	197942	197942	197942	197942	-14368618	-718431
DEFERRED INCOME TAX	-542753	-542753	-542753	-542753	-2	0
TOTAL INCOME TAXES	-344811	-344811	-344811	-344811	-14368620	-718431
NET INCOME (BOOK)	-373545	-373545	-373545	-373545	1500	75
SOURCES OF FUNDS						
NET INCOME	-373545	-373545	-373545	-373545	1500	75
FINANCIAL DEPRECIATION	3736200	3736200	3736200	3736200	74724000	3736200
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-542753	-542753	-542753	-542753	-2	0
NET ADDITIONS TO EQUITY	0	0	0	0	74724000	3736200
TOTAL SOURCES	2819902	2819902	2819902	2819902	149449498	7472475
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	74724000	3736200
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	74724000	3736200
NET CASH GENERATED DURING YEAR	2819902	2819902	2819902	2819902	74725498	3736275
CUMULATIVE NET CASH GENERATED	66265792	69085694	71905596	74725498	929817330	46490867
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545178

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP1 GAS PROCESSING AT PRUDHOE -2000 MMSCFD -EXTRACT C2+

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY VOLUME (BBLS)	0	0	155300	155300	155300	155300	155300	155300	155300
COST OF SERVICE ($/BBL)	.412	.412	.412	.412	.412	.412	.412	.412	.412
TOTAL REVENUE	0	0	23369827	23369827	23369827	23369827	23369827	23369827	23369827
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	10850000	10850000	10850000	10850000	10850000	10850000	10850000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	15500000	15500000	15500000	15500000	15500000	15500000	15500000
TOTAL EXPENSES	0	0	26350000	26350000	26350000	26350000	26350000	26350000	26350000
INCOME BEFORE TAXES	0	0	-2980173	-2980173	-2980173	-2980173	-2980173	-2980173	-2980173
INVESTMENT TAX CREDIT	0	0	31000000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	31000000	27900000	25110000	22599000	20339100	18305190	16474671
TAXABLE INCOME	0	0	-18480173	-15380173	-12590173	-10079173	-7819273	-5785363	-3954844
CURRENT INCOME TAX	0	0	-3987048	-7382483	-6043283	-4838003	-3753251	-2776974	-1898325
DEFERRED INCOME TAX	0	0	7440000	5952000	4612800	3407520	2322768	1346491	467842
TOTAL INCOME TAXES	0	0	-32430483	-1430483	-1430483	-1430483	-1430483	-1430483	-1430483
NET INCOME (BOOK)	0	0	29450310	-1549690	-1549690	-1549690	-1549690	-1549690	-1549690
SOURCES OF FUNDS									
NET INCOME	0	0	29450310	-1549690	-1549690	-1549690	-1549690	-1549690	-1549690
FINANCIAL DEPRECIATION	0	0	15500000	15500000	15500000	15500000	15500000	15500000	15500000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	7440000	5952000	4612800	3407520	2322768	1346491	467842
NET ADDITIONS TO EQUITY	155000000	155000000	0	0	0	0	0	0	0
TOTAL SOURCES	155000000	155000000	52390310	19902310	18563110	17357830	16273078	15296801	14418152
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	155000000	155000000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	155000000	155000000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	52390310	19902310	18563110	17357830	16273078	15296801	14418152
CUMULATIVE NET CASH GENERATED	0	0	52390310	72292620	90855730	108213560	124486638	139783439	154201591
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545179

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP1 GAS PROCESSING AT PRUDHOE -2000 MMSCFD -EXTRACT C2+

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY VOLUME (BBLS)	155300	155300	155300	155300	155300	155300	155300	155300	155300
COST OF SERVICE ($/BBL)	.412	.412	.412	.412	.412	.412	.412	.412	.412
TOTAL REVENUE	23369827	23369827	23369827	23369827	23369827	23369827	23369827	23369827	23369827
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	10850000	10850000	10850000	10850000	10850000	10850000	10850000	10850000	10850000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	15500000	15500000	15500000	15500000	15500000	15500000	15500000	15500000	15500000
TOTAL EXPENSES	26350000	26350000	26350000	26350000	26350000	26350000	26350000	26350000	26350000
INCOME BEFORE TAXES	-2980173	-2980173	-2980173	-2980173	-2980173	-2980173	-2980173	-2980173	-2980173
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	14827204	13344484	12010035	10809032	10809032	10809032	10809032	10809032	10809032
TAXABLE INCOME	-2307377	-824657	509792	1710795	1710795	1710795	1710795	1710795	1710795
CURRENT INCOME TAX	-1107541	-395835	244700	821182	821182	821182	821182	821182	821182
DEFERRED INCOME TAX	-322942	-1034648	-1675183	-2251665	-2251665	-2251665	-2251665	-2251665	-2251665
TOTAL INCOME TAXES	-1430483	-1430483	-1430483	-1430483	-1430483	-1430483	-1430483	-1430483	-1430483
NET INCOME (BOOK)	-1549690	-1549690	-1549690	-1549690	-1549690	-1549690	-1549690	-1549690	-1549690
SOURCES OF FUNDS									
NET INCOME	-1549690	-1549690	-1549690	-1549690	-1549690	-1549690	-1549690	-1549690	-1549690
FINANCIAL DEPRECIATION	15500000	15500000	15500000	15500000	15500000	15500000	15500000	15500000	15500000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-322942	-1034648	-1675183	-2251665	-2251665	-2251665	-2251665	-2251665	-2251665
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	13627368	12915552	12275127	11698645	11698645	11698645	11698645	11698645	11698645
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	13627368	12915552	12275127	11698645	11698645	11698645	11698645	11698645	11698645
CUMULATIVE NET CASH GENERATED	167928959	180744521	193019748	204718393	216417038	228115683	239814328	251512973	263211618
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO-545180

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP1 GAS PROCESSING AT PRUDHOE -2000 MMSCFD -EXTRACT C2+

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY VOLUME (BBLS)	155300	155300	155300	155300	3106000	155300
COST OF SERVICE (¢/BBL)	.412	.412	.412	.412	9.064	.453
TOTAL REVENUE	23369827	23369827	23369827	23369827	467396540	23369827
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	10850000	10850000	10850000	10850000	217000000	10850000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	15500000	15500000	15500000	15500000	310000000	15500000
TOTAL EXPENSES	26350000	26350000	26350000	26350000	527000000	26350000
INCOME BEFORE TAXES	-2980173	-2980173	-2980173	-2980173	-59603460	-2980173
INVESTMENT TAX CREDIT	0	0	0	0	31000000	1550000
TAX DEPRECIATION	10809032	10809032	10809032	10809032	310000004	15500000
TAXABLE INCOME	1710795	1710795	1710795	1710795	-59603464	-2980173
CURRENT INCOME TAX	821182	821182	821182	821182	-59609658	-2980483
DEFERRED INCOME TAX	-2251665	-2251665	-2251665	-2251665	-2	0
TOTAL INCOME TAXES	-1430483	-1430483	-1430483	-1430483	-59609660	-2980483
NET INCOME (BOOK)	-1549690	-1549690	-1549690	-1549690	6200	310
SOURCES OF FUNDS						
NET INCOME	-1549690	-1549690	-1549690	-1549690	6200	310
FINANCIAL DEPRECIATION	15500000	15500000	15500000	15500000	310000000	15500000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2251665	-2251665	-2251665	-2251665	-2	0
NET ADDITIONS TO EQUITY	0	0	0	0	310000000	15500000
TOTAL SOURCES	11698645	11698645	11698645	11698645	620006198	31000310
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	310000000	15500000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	310000000	15500000
NET CASH GENERATED DURING YEAR	11698645	11698645	11698645	11698645	310006198	15500310
CUMULATIVE NET CASH GENERATED	274910263	286608908	298307553	310006198	3857440171	1928720090
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545181

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP2 GAS PROCESSING AT PRUDHOE -2000 MMSCFD -EXTRACT C3+

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY VOLUME (BBLS)	0	0	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	.686	.686	.686	.686	.686	.686	.686	.686	.686
TOTAL REVENUE	0	0	17715837	17715837	17715837	17715837	17715837	17715837	17715837
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	8225000	8225000	8225000	8225000	8225000	8225000	8225000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	11750000	11750000	11750000	11750000	11750000	11750000	11750000
TOTAL EXPENSES	0	0	19975000	19975000	19975000	19975000	19975000	19975000	19975000
INCOME BEFORE TAXES	0	0	-2259163	-2259163	-2259163	-2259163	-2259163	-2259163	-2259163
INVESTMENT TAX CREDIT	0	0	23500000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	23500000	21150000	19035000	17131500	15418350	13876515	12488864
TAXABLE INCOME	0	0	-14009163	-11659163	-9544163	-7640663	-5927513	-4385678	-2998027
CURRENT INCOME TAX	0	0	-30224398	-5596398	-4581198	-3667518	-2845206	-2105126	-1439053
DEFERRED INCOME TAX	0	0	5640000	4512000	3496800	2583120	1760808	1020728	354655
TOTAL INCOME TAXES	0	0	-24584398	-1084398	-1084398	-1084398	-1084398	-1084398	-1084398
NET INCOME (BOOK)	0	0	22325235	-1174765	-1174765	-1174765	-1174765	-1174765	-1174765
SOURCES OF FUNDS									
NET INCOME	0	0	22325235	-1174765	-1174765	-1174765	-1174765	-1174765	-1174765
FINANCIAL DEPRECIATION	0	0	11750000	11750000	11750000	11750000	11750000	11750000	11750000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	5640000	4512000	3496800	2583120	1760808	1020728	354655
NET ADDITIONS TO EQUITY	117500000	117500000	0	0	0	0	0	0	0
TOTAL SOURCES	117500000	117500000	39715235	15087235	14072035	13158355	12336043	11595963	10929890
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	117500000	117500000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	117500000	117500000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	39715235	15087235	14072035	13158355	12336043	11595963	10929890
CUMULATIVE NET CASH GENERATED	0	0	39715235	54802470	68874505	82032860	94368903	105964866	116894756
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545182

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP2 GAS PROCESSING AT PRUDHOE -2000 MMSCFD -EXTRACT C3+

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY VOLUME (BBLS)	70800	70800	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	.686	.686	.686	.686	.686	.686	.686	.686	.686
TOTAL REVENUE	17715837	17715837	17715837	17715837	17715837	17715837	17715837	17715837	17715837
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	8225000	8225000	8225000	8225000	8225000	8225000	8225000	8225000	8225000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	11750000	11750000	11750000	11750000	11750000	11750000	11750000	11750000	11750000
TOTAL EXPENSES	19975000	19975000	19975000	19975000	19975000	19975000	19975000	19975000	19975000
INCOME BEFORE TAXES	-2259163	-2259163	-2259163	-2259163	-2259163	-2259163	-2259163	-2259163	-2259163
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	11239977	10115979	9104381	8193943	8193943	8193943	8193943	8193943	8193943
TAXABLE INCOME	-1749140	-625142	386456	1296894	1296894	1296894	1296894	1296894	1296894
CURRENT INCOME TAX	-839587	-300069	185498	622509	622509	622509	622509	622509	622509
DEFERRED INCOME TAX	-244811	-784329	-1269896	-1706907	-1706907	-1706907	-1706907	-1706907	-1706907
TOTAL INCOME TAXES	-1084398	-1084398	-1084398	-1084398	-1084398	-1084398	-1084398	-1084398	-1084398
NET INCOME (BOOK)	-1174765	-1174765	-1174765	-1174765	-1174765	-1174765	-1174765	-1174765	-1174765
SOURCES OF FUNDS									
NET INCOME	-1174765	-1174765	-1174765	-1174765	-1174765	-1174765	-1174765	-1174765	-1174765
FINANCIAL DEPRECIATION	11750000	11750000	11750000	11750000	11750000	11750000	11750000	11750000	11750000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-244811	-784329	-1269896	-1706907	-1706907	-1706907	-1706907	-1706907	-1706907
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	10330424	9790906	9305339	8868328	8868328	8868328	8868328	8868328	8868328
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	10330424	9790906	9305339	8868328	8868328	8868328	8868328	8868328	8868328
CUMULATIVE NET CASH GENERATED	127225180	137016086	146321425	155189753	164058081	172926409	181794737	190663065	199531393
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545183

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP2 GAS PROCESSING AT PRUDHOE -2000 MMSCFD -EXTRACT C3+

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY VOLUME (BBLS)	70800	70800	70800	70800	1416000	70800
COST OF SERVICE ($/BBL)	.686	.686	.686	.686	15.092	.755
TOTAL REVENUE	17715837	17715837	17715837	17715837	354316740	17715837
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	8225000	8225000	8225000	8225000	164500000	8225000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	11750000	11750000	11750000	11750000	235000000	11750000
TOTAL EXPENSES	19975000	19975000	19975000	19975000	399500000	19975000
INCOME BEFORE TAXES	-2259163	-2259163	-2259163	-2259163	-45183260	-2259163
INVESTMENT TAX CREDIT	0	0	0	0	23500000	1175000
TAX DEPRECIATION	8193943	8193943	8193943	8193943	234999936	11750000
TAXABLE INCOME	1296894	1296894	1296894	1296894	-45183256	-2259163
CURRENT INCOME TAX	622509	622509	622509	622509	-45187955	-2259398
DEFERRED INCOME TAX	-1706907	-1706907	-1706907	-1706907	5	0
TOTAL INCOME TAXES	-1084398	-1084398	-1084398	-1084398	-45187960	-2259398
NET INCOME (BOOK)	-1174765	-1174765	-1174765	-1174765	4700	235
SOURCES OF FUNDS						
NET INCOME	-1174765	-1174765	-1174765	-1174765	4700	235
FINANCIAL DEPRECIATION	11750000	11750000	11750000	11750000	235000000	11750000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1706907	-1706907	-1706907	-1706907	5	0
NET ADDITIONS TO EQUITY	0	0	0	0	235000000	11750000
TOTAL SOURCES	8868328	8868328	8868328	8868328	470004705	23500235
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	235000000	11750000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	235000000	11750000
NET CASH GENERATED DURING YEAR	8868328	8868328	8868328	8868328	235004705	11750235
CUMULATIVE NET CASH GENERATED	208399721	217268049	226136377	235004705	2924188576	146209429
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545184

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP3 GAS PROCESSING AT FAIRBANKS -2000 MMSCFD -EXTRACT C2+

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY VOLUME (BBLS)	0	0	155300	155300	155300	155300	155300	155300	155300
COST OF SERVICE ($/BBL)	.330	.330	.330	.330	.330	.330	.330	.330	.330
TOTAL REVENUE	0	0	18695862	18695862	18695862	18695862	18695862	18695862	18695862
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	8680000	8680000	8680000	8680000	8680000	8680000	8680000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	12400000	12400000	12400000	12400000	12400000	12400000	12400000
TOTAL EXPENSES	0	0	21080000	21080000	21080000	21080000	21080000	21080000	21080000
INCOME BEFORE TAXES	0	0	-2384138	-2384138	-2384138	-2384138	-2384138	-2384138	-2384138
INVESTMENT TAX CREDIT	0	0	24800000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	24800000	22320000	20088000	18079200	16271280	14644152	13179737
TAXABLE INCOME	0	0	-14784138	-12304138	-10072138	-8063338	-6255418	-4628290	-3163875
CURRENT INCOME TAX	0	0	-31896386	-5905986	-4834626	-3870402	-3002601	-2221579	-1518660
DEFERRED INCOME TAX	0	0	5952000	4761600	3690240	2726016	1858215	1077193	374274
TOTAL INCOME TAXES	0	0	-25944386	-1144386	-1144386	-1144386	-1144386	-1144386	-1144386
NET INCOME (BOOK)	0	0	23560248	-1239752	-1239752	-1239752	-1239752	-1239752	-1239752
SOURCES OF FUNDS									
NET INCOME	0	0	23560248	-1239752	-1239752	-1239752	-1239752	-1239752	-1239752
FINANCIAL DEPRECIATION	0	0	12400000	12400000	12400000	12400000	12400000	12400000	12400000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	5952000	4761600	3690240	2726016	1858215	1077193	374274
NET ADDITIONS TO EQUITY	124000000	124000000	0	0	0	0	0	0	0
TOTAL SOURCES	124000000	124000000	41912248	15921848	14850488	13886264	13018463	12237441	11534522
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	124000000	124000000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	124000000	124000000	0	0	0	0	0	0	0
NET CASH GENERATED DUPING YEAR	0	0	41912248	15921848	14850488	13886264	13018463	12237441	11534522
CUMULATIVE NET CASH GENERATED	0	0	41912248	57834096	72684584	86570848	99589311	111826752	123361274
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545185

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP3 GAS PROCESSING AT FAIRBANKS -2000 MMSCFD -EXTRACT C2+

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY VOLUME (BBLS)	155300	155300	155300	155300	155300	155300	155300	155300	155300
COST OF SERVICE ($/BBL)	.330	.330	.330	.330	.330	.330	.330	.330	.330
TOTAL REVENUE	18695862	18695862	18695862	18695862	18695862	18695862	18695862	18695862	18695862
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	8680000	8680000	8680000	8680000	8680000	8680000	8680000	8680000	8680000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	12400000	12400000	12400000	12400000	12400000	12400000	12400000	12400000	12400000
TOTAL EXPENSES	21080000	21080000	21080000	21080000	21080000	21080000	21080000	21080000	21080000
INCOME BEFORE TAXES	-2384138	-2384138	-2384138	-2384138	-2384138	-2384138	-2384138	-2384138	-2384138
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	11861763	10675587	9608028	8647225	8647225	8647225	8647225	8647225	8647225
TAXABLE INCOME	-1845901	-659725	407834	1368637	1368637	1368637	1368637	1368637	1368637
CURRENT INCOME TAX	-886033	-316668	195760	656945	656945	656945	656945	656945	656945
DEFERRED INCOME TAX	-258353	-827718	-1340146	-1801331	-1801331	-1801331	-1801331	-1801331	-1801331
TOTAL INCOME TAXES	-1144386	-1144386	-1144386	-1144386	-1144386	-1144386	-1144386	-1144386	-1144386
NET INCOME (BOOK)	-1239752	-1239752	-1239752	-1239752	-1239752	-1239752	-1239752	-1239752	-1239752
SOURCES OF FUNDS									
NET INCOME	-1239752	-1239752	-1239752	-1239752	-1239752	-1239752	-1239752	-1239752	-1239752
FINANCIAL DEPRECIATION	12400000	12400000	12400000	12400000	12400000	12400000	12400000	12400000	12400000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-258353	-827718	-1340146	-1801331	-1801331	-1801331	-1801331	-1801331	-1801331
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	10901895	10332530	9820102	9358917	9358917	9358917	9358917	9358917	9358917
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	10901895	10332530	9820102	9358917	9358917	9358917	9358917	9358917	9358917
CUMULATIVE NET CASH GENERATED	134263169	144595699	154415801	163774718	173133635	182492552	191851469	201210386	210569303
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

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EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP3 GAS PROCESSING AT FAIRBANKS -2000 MMSCFD -EXTRACT C2+

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY VOLUME (BBLS)	155300	155300	155300	155300	3106000	155300
COST OF SERVICE ($/BBL)	.330	.330	.330	.330	7.260	.363
TOTAL REVENUE	18695862	18695862	18695862	18695862	373917240	18695862
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	8680000	8680000	8680000	8680000	173600000	8680000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	12400000	12400000	12400000	12400000	248000000	12400000
TOTAL EXPENSES	21080000	21080000	21080000	21080000	421600000	21080000
INCOME BEFORE TAXES	-2384138	-2384138	-2384138	-2384138	-47682760	-2384138
INVESTMENT TAX CREDIT	0	0	0	0	24800000	1240000
TAX DEPRECIATION	8647225	8647225	8647225	8647225	247999997	12400000
TAXABLE INCOME	1368637	1368637	1368637	1368637	-47682757	-2384138
CURRENT INCOME TAX	656945	656945	656945	656945	-47687731	-2384387
DEFERRED INCOME TAX	-1801331	-1801331	-1801331	-1801331	11	1
TOTAL INCOME TAXES	-1144386	-1144386	-1144386	-1144386	-47687720	-2384386
NET INCOME (BOOK)	-1239752	-1239752	-1239752	-1239752	4960	248
SOURCES OF FUNDS						
NET INCOME	-1239752	-1239752	-1239752	-1239752	4960	248
FINANCIAL DEPRECIATION	12400000	12400000	12400000	12400000	248000000	12400000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1801331	-1801331	-1801331	-1801331	11	1
NET ADDITIONS TO EQUITY	0	0	0	0	248000000	12400000
TOTAL SOURCES	9358917	9358917	9358917	9358917	496004971	24800249
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	248000000	12400000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	248000000	12400000
NET CASH GENERATED DURING YEAR	9358917	9358917	9358917	9358917	248004971	12400249
CUMULATIVE NET CASH GENERATED	219928220	229287137	238646054	248004971	13085952227	154297611
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545187

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP4 GAS PROCESSING AT FAIRBANKS -2000 MMSCFD -EXTRACT C3+

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY VOLUME (BBLS)	0	0	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	.543	.543	.543	.543	.543	.543	.543	.543	.543
TOTAL REVENUE	0	0	14021896	14021896	14021896	14021896	14021896	14021896	14021896
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	6510000	6510000	6510000	6510000	6510000	6510000	6510000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	9300000	9300000	9300000	9300000	9300000	9300000	9300000
TOTAL EXPENSES	0	0	15810000	15810000	15810000	15810000	15810000	15810000	15810000
INCOME BEFORE TAXES	0	0	-1788104	-1788104	-1788104	-1788104	-1788104	-1788104	-1788104
INVESTMENT TAX CREDIT	0	0	18600000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	18600000	16740000	15066000	13559400	12203460	10983114	9884803
TAXABLE INCOME	0	0	-11088104	-9228104	-7554104	-6047504	-4691564	-3471218	-2372907
CURRENT INCOME TAX	0	0	-23922290	-4429490	-3625970	-2902802	-2251951	-1666185	-1138995
DEFERRED INCOME TAX	0	0	4464000	3571200	2767680	2044512	1393661	807895	280705
TOTAL INCOME TAXES	0	0	-19458290	-858290	-858290	-858290	-858290	-858290	-858290
NET INCOME (BOOK)	0	0	17670186	-929814	-929814	-929814	-929814	-929814	-929814
SOURCES OF FUNDS									
NET INCOME	0	0	17670186	-929814	-929814	-929814	-929814	-929814	-929814
FINANCIAL DEPRECIATION	0	0	9300000	9300000	9300000	9300000	9300000	9300000	9300000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	4464000	3571200	2767680	2044512	1393661	807895	280705
NET ADDITIONS TO EQUITY	93000000	93000000	0	0	0	0	0	0	0
TOTAL SOURCES	93000000	93000000	31434186	11941386	11137866	10414698	9763847	9178081	8650891
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	93000000	93000000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	93000000	93000000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	31434186	11941386	11137866	10414698	9763847	9178081	8650891
CUMULATIVE NET CASH GENERATED	0	0	31434186	43375572	54513438	64928136	74691983	83870064	92520955
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545188

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP4 GAS PROCESSING AT FAIRBANKS -2000 MMSCFD -EXTRACT C3+

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY VOLUME (BBLS)	70800	70800	70800	70800	70800	70800	70800	70800	70800
COST OF SERVICE ($/BBL)	.543	.543	.543	.543	.543	.543	.543	.543	.543
TOTAL REVENUE	14021896	14021896	14021896	14021896	14021896	14021896	14021896	14021896	14021896
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	6510000	6510000	6510000	6510000	6510000	6510000	6510000	6510000	6510000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	9300000	9300000	9300000	9300000	9300000	9300000	9300000	9300000	9300000
TOTAL EXPENSES	15810000	15810000	15810000	15810000	15810000	15810000	15810000	15810000	15810000
INCOME BEFORE TAXES	-1788104	-1788104	-1788104	-1788104	-1788104	-1788104	-1788104	-1788104	-1788104
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	8896322	8006690	7206021	6485419	6485419	6485419	6485419	6485419	6485419
TAXABLE INCOME	-1384426	-494794	305875	1026477	1026477	1026477	1026477	1026477	1026477
CURRENT INCOME TAX	-664525	-237501	146820	492709	492709	492709	492709	492709	492709
DEFERRED INCOME TAX	-193765	-620789	-1005110	-1350999	-1350999	-1350999	-1350999	-1350999	-1350999
TOTAL INCOME TAXES	-858290	-858290	-858290	-858290	-858290	-858290	-858290	-858290	-858290
NET INCOME (BOOK)	-929814	-929814	-929814	-929814	-929814	-929814	-929814	-929814	-929814
SOURCES OF FUNDS									
NET INCOME	-929814	-929814	-929814	-929814	-929814	-929814	-929814	-929814	-929814
FINANCIAL DEPRECIATION	9300000	9300000	9300000	9300000	9300000	9300000	9300000	9300000	9300000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-193765	-620789	-1005110	-1350999	-1350999	-1350999	-1350999	-1350999	-1350999
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	8176421	7749397	7365076	7019187	7019187	7019187	7019187	7019187	7019187
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	8176421	7749397	7365076	7019187	7019187	7019187	7019187	7019187	7019187
CUMULATIVE NET CASH GENERATED	100697376	108446773	115811849	122831036	129850223	136869410	143888597	150907784	157926971
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545189

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP4 GAS PROCESSING AT FAIRBANKS -2000 MMSCFD -EXTRACT C3+

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY VOLUME (BBLS)	70800	70800	70800	70800	1416000	70800
COST OF SERVICE ($/BBL)	.543	.543	.543	.543	11.946	.597
TOTAL REVENUE	14021896	14021896	14021896	14021896	280437920	14021896
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	6510000	6510000	6510000	6510000	130200000	6510000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	9300000	9300000	9300000	9300000	186000000	9300000
TOTAL EXPENSES	15810000	15810000	15810000	15810000	316200000	15810000
INCOME BEFORE TAXES	-1788104	-1788104	-1788104	-1788104	-35762080	-1788104
INVESTMENT TAX CREDIT	0	0	0	0	18600000	930000
TAX DEPRECIATION	6485419	6485419	6485419	6485419	186000000	9300000
TAXABLE INCOME	1026477	1026477	1026477	1026477	-35762080	-1788104
CURRENT INCOME TAX	492709	492709	492709	492709	-35765799	-1788290
DEFERRED INCOME TAX	-1350999	-1350999	-1350999	-1350999	-1	0
TOTAL INCOME TAXES	-858290	-858290	-858290	-858290	-35765800	-1788290
NET INCOME (BOOK)	-929814	-929814	-929814	-929814	3720	186
SOURCES OF FUNDS						
NET INCOME	-929814	-929814	-929814	-929814	3720	186
FINANCIAL DEPRECIATION	9300000	9300000	9300000	9300000	186000000	9300000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1350999	-1350999	-1350999	-1350999	-1	0
NET ADDITIONS TO EQUITY	0	0	0	0	186000000	9300000
TOTAL SOURCES	7019187	7019187	7019187	7019187	372003719	18600186
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	186000000	9300000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	186000000	9300000
NET CASH GENERATED DURING YEAR	7019187	7019187	7019187	7019187	186003719	9300186
CUMULATIVE NET CASH GENERATED	164946158	171965345	178984532	186003719	2314464107	115723205
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545190

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP5 GAS PROCESSING AT PRUDHOE -250 MMSCFD -EXTRACT C2+

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY VOLUME (BBLS)	0	0	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	.586	.586	.586	.586	.586	.586	.586	.586	.586
TOTAL REVENUE	0	0	4146260	4146260	4146260	4146260	4146260	4146260	4146260
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	1925000	1925000	1925000	1925000	1925000	1925000	1925000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	2750000	2750000	2750000	2750000	2750000	2750000	2750000
TOTAL EXPENSES	0	0	4675000	4675000	4675000	4675000	4675000	4675000	4675000
INCOME BEFORE TAXES	0	0	-528740	-528740	-528740	-528740	-528740	-528740	-528740
INVESTMENT TAX CREDIT	0	0	5500000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	5500000	4950000	4455000	4009500	3608550	3247695	2922926
TAXABLE INCOME	0	0	-3278740	-2728740	-2233740	-1788240	-1387290	-1026435	-701666
CURRENT INCOME TAX	0	0	-7073795	-1309795	-1072195	-858355	-665899	-492689	-336800
DEFERRED INCOME TAX	0	0	1320000	1056000	818400	604560	412104	238894	83005
TOTAL INCOME TAXES	0	0	-5753795	-253795	-253795	-253795	-253795	-253795	-253795
NET INCOME (BOOK)	0	0	5225055	-274945	-274945	-274945	-274945	-274945	-274945
SOURCES OF FUNDS									
NET INCOME	0	0	5225055	-274945	-274945	-274945	-274945	-274945	-274945
FINANCIAL DEPRECIATION	0	0	2750000	2750000	2750000	2750000	2750000	2750000	2750000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	1320000	1056000	818400	604560	412104	238894	83005
NET ADDITIONS TO EQUITY	27500000	27500000	0	0	0	0	0	0	0
TOTAL SOURCES	27500000	27500000	9295055	3531055	3293455	3079615	2887159	2713949	2558060
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	27500000	27500000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	27500000	27500000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	9295055	3531055	3293455	3079615	2887159	2713949	2558060
CUMULATIVE NET CASH GENERATED	0	0	9295055	12826110	16119565	19199180	22086339	24800288	27358348
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545191

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP5 GAS PROCESSING AT PRUDHOE -250 MMSCFD -EXTRACT C2+

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY VOLUME (BBLS)	19400	19400	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	.586	.586	.586	.586	.586	.586	.586	.586	.586
TOTAL REVENUE	4146260	4146260	4146260	4146260	4146260	4146260	4146260	4146260	4146260
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	1925000	1925000	1925000	1925000	1925000	1925000	1925000	1925000	1925000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	2750000	2750000	2750000	2750000	2750000	2750000	2750000	2750000	2750000
TOTAL EXPENSES	4675000	4675000	4675000	4675000	4675000	4675000	4675000	4675000	4675000
INCOME BEFORE TAXES	-528740	-528740	-528740	-528740	-528740	-528740	-528740	-528740	-528740
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	2630633	2367570	2130813	1917731	1917731	1917731	1917731	1917731	1917731
TAXABLE INCOME	-409373	-146310	90447	303529	303529	303529	303529	303529	303529
CURRENT INCOME TAX	-196499	-70229	43415	145694	145694	145694	145694	145694	145694
DEFERRED INCOME TAX	-57296	-183566	-297210	-399489	-399489	-399489	-399489	-399489	-399489
TOTAL INCOME TAXES	-253795	-253795	-253795	-253795	-253795	-253795	-253795	-253795	-253795
NET INCOME (BOOK)	-274945	-274945	-274945	-274945	-274945	-274945	-274945	-274945	-274945
SOURCES OF FUNDS									
NET INCOME	-274945	-274945	-274945	-274945	-274945	-274945	-274945	-274945	-274945
FINANCIAL DEPRECIATION	2750000	2750000	2750000	2750000	2750000	2750000	2750000	2750000	2750000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-57296	-183566	-297210	-399489	-399489	-399489	-399489	-399489	-399489
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	2417759	2291489	2177845	2075566	2075566	2075566	2075566	2075566	2075566
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	2417759	2291489	2177845	2075566	2075566	2075566	2075566	2075566	2075566
CUMULATIVE NET CASH GENERATED	29776107	32067596	34245441	36321007	38396573	40472139	42547705	44623271	46698837
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545192

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP5 GAS PROCESSING AT PRUDHOE -250 MMSCFD -EXTRACT C2+

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY VOLUME (BBLS)	19400	19400	19400	19400	388000	19400
COST OF SERVICE ($/BBL)	.586	.586	.586	.586	12.892	.645
TOTAL REVENUE	4146260	4146260	4146260	4146260	82925200	4146260
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	1925000	1925000	1925000	1925000	38500000	1925000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	2750000	2750000	2750000	2750000	55000000	2750000
TOTAL EXPENSES	4675000	4675000	4675000	4675000	93500000	4675000
INCOME BEFORE TAXES	-528740	-528740	-528740	-528740	-10574800	-528740
INVESTMENT TAX CREDIT	0	0	0	0	5500000	275000
TAX DEPRECIATION	1917731	1917731	1917731	1917731	54999997	2750000
TAXABLE INCOME	303529	303529	303529	303529	-10574797	-528740
CURRENT INCOME TAX	145694	145694	145694	145694	-10575901	-528795
DEFERRED INCOME TAX	-399489	-399489	-399489	-399489	1	0
TOTAL INCOME TAXES	-253795	-253795	-253795	-253795	-10575900	-528795
NET INCOME (BOOK)	-274945	-274945	-274945	-274945	1100	55
SOURCES OF FUNDS						
NET INCOME	-274945	-274945	-274945	-274945	1100	55
FINANCIAL DEPRECIATION	2750000	2750000	2750000	2750000	55000000	2750000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-399489	-399489	-399489	-399489	1	0
NET ADDITIONS TO EQUITY	0	0	0	0	55000000	2750000
TOTAL SOURCES	2075566	2075566	2075566	2075566	110001101	5500055
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	55000000	2750000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	55000000	2750000
NET CASH GENERATED DURING YEAR	2075566	2075566	2075566	2075566	55001101	2750055
CUMULATIVE NET CASH GENERATED	48774403	50849969	52925535	55001101	684384569	54219226
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545193

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP6 GAS PROCESSING AT PRUDHOE -250 MMSCFD -EXTRACT C3+

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY VOLUME (BBLS)	0	0	8900	8900	8900	8900	8900	8900	8900
COST OF SERVICE (¢/BBL)	.951	.951	.951	.951	.951	.951	.951	.951	.951
TOTAL REVENUE	0	0	3090848	3090848	3090848	3090848	3090848	3090848	3090848
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	1435000	1435000	1435000	1435000	1435000	1435000	1435000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	2050000	2050000	2050000	2050000	2050000	2050000	2050000
TOTAL EXPENSES	0	0	3485000	3485000	3485000	3485000	3485000	3485000	3485000
INCOME BEFORE TAXES	0	0	-394152	-394152	-394152	-394152	-394152	-394152	-394152
INVESTMENT TAX CREDIT	0	0	4100000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	4100000	3690000	3321000	2988900	2690010	2421009	2178908
TAXABLE INCOME	0	0	-2444152	-2034152	-1665152	-1333052	-1034162	-765161	-523060
CURRENT INCOME TAX	0	0	-5273193	-976393	-799273	-639865	-496398	-367277	-251069
DEFERRED INCOME TAX	0	0	984000	787200	610080	450672	307205	178084	61876
TOTAL INCOME TAXES	0	0	-4289193	-189193	-189193	-189193	-189193	-189193	-189193
NET INCOME (BOOK)	0	0	3895041	-204959	-204959	-204959	-204959	-204959	-204959
SOURCES OF FUNDS									
NET INCOME	0	0	3895041	-204959	-204959	-204959	-204959	-204959	-204959
FINANCIAL DEPRECIATION	0	0	2050000	2050000	2050000	2050000	2050000	2050000	2050000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	984000	787200	610080	450672	307205	178084	61876
NET ADDITIONS TO EQUITY	20500000	20500000	0	0	0	0	0	0	0
TOTAL SOURCES	20500000	20500000	6929041	2632241	2455121	2295713	2152246	2023125	1906917
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	20500000	20500000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	20500000	20500000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	6929041	2632241	2455121	2295713	2152246	2023125	1906917
CUMULATIVE NET CASH GENERATED	0	0	6929041	9561282	12016403	14312116	16464362	18487487	20394404
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGD 545194

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP6 GAS PROCESSING AT PRUDHOE -250 MMSCFD -EXTRACT C3+

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY VOLUME (BBLS)	8900	8900	8900	8900	8900	8900	8900	8900	8900
COST OF SERVICE ($/BBL)	.951	.951	.951	.951	.951	.951	.951	.951	.951
TOTAL REVENUE	3090848	3090848	3090848	3090848	3090848	3090848	3090848	3090848	3090848
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	1435000	1435000	1435000	1435000	1435000	1435000	1435000	1435000	1435000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	2050000	2050000	2050000	2050000	2050000	2050000	2050000	2050000	2050000
TOTAL EXPENSES	3485000	3485000	3485000	3485000	3485000	3485000	3485000	3485000	3485000
INCOME BEFORE TAXES	-394152	-394152	-394152	-394152	-394152	-394152	-394152	-394152	-394152
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	1961017	1764916	1588424	1429582	1429582	1429582	1429582	1429582	1429582
TAXABLE INCOME	-305169	-109068	57424	226266	226266	226266	226266	226266	226266
CURRENT INCOME TAX	-146481	-52352	32764	108608	108608	108608	108608	108608	108608
DEFERRED INCOME TAX	-42712	-136841	-221557	-297801	-297801	-297801	-297801	-297801	-297801
TOTAL INCOME TAXES	-189193	-189193	-189193	-189193	-189193	-189193	-189193	-189193	-189193
NET INCOME (BOOK)	-204959	-204959	-204959	-204959	-204959	-204959	-204959	-204959	-204959
SOURCES OF FUNDS									
NET INCOME	-204959	-204959	-204959	-204959	-204959	-204959	-204959	-204959	-204959
FINANCIAL DEPRECIATION	2050000	2050000	2050000	2050000	2050000	2050000	2050000	2050000	2050000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-42712	-136841	-221557	-297801	-297801	-297801	-297801	-297801	-297801
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	1802329	1708200	1623484	1547240	1547240	1547240	1547240	1547240	1547240
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	1802329	1708200	1623484	1547240	1547240	1547240	1547240	1547240	1547240
CUMULATIVE NET CASH GENERATED	22196733	23904933	25528417	27075657	28622897	30170137	31717377	33264617	34811857
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545195

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP6 GAS PROCESSING AT PRUDHOE -250 MMSCFD -EXTRACT C3+

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY VOLUME (BBLS)	8900	8900	8900	8900	178000	8900
COST OF SERVICE ($/BBL)	.951	.951	.951	.951	20.922	1.046
TOTAL REVENUE	3090848	3090848	3090848	3090848	61816960	3090848
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	1435000	1435000	1435000	1435000	28700000	1435000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	2050000	2050000	2050000	2050000	41000000	2050000
TOTAL EXPENSES	3485000	3485000	3485000	3485000	69700000	3485000
INCOME BEFORE TAXES	-394152	-394152	-394152	-394152	-7883040	-394152
INVESTMENT TAX CREDIT	0	0	0	0	4100000	205000
TAX DEPRECIATION	1429582	1429582	1429582	1429582	41000004	2050000
TAXABLE INCOME	226266	226266	226266	226266	-7883044	-394152
CURRENT INCOME TAX	108608	108608	108608	108608	-7883857	-394193
DEFERRED INCOME TAX	-297801	-297801	-297801	-297801	-3	0
TOTAL INCOME TAXES	-189193	-189193	-189193	-189193	-7883860	-394193
NET INCOME (BOOK)	-204959	-204959	-204959	-204959	820	41
SOURCES OF FUNDS						
NET INCOME	-204959	-204959	-204959	-204959	820	41
FINANCIAL DEPRECIATION	2050000	2050000	2050000	2050000	41000000	2050000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-297801	-297801	-297801	-297801	-3	0
NET ADDITIONS TO EQUITY	0	0	0	0	41000000	2050000
TOTAL SOURCES	1547240	1547240	1547240	1547240	82000817	4100041
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	41000000	2050000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	41000000	2050000
NET CASH GENERATED DURING YEAR	1547240	1547240	1547240	1547240	41000817	2050041
CUMULATIVE NET CASH GENERATED	36359097	37906337	39453577	41000817	510177548	25508877
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545196

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP7 GAS PROCESSING AT FAIRBANKS -250 MMSCFD -EXTRACT C2+

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY VOLUME (BBLS)	0	0	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	.447	.447	.447	.447	.447	.447	.447	.447	.447
TOTAL REVENUE	0	0	3166235	3166235	3166235	3166235	3166235	3166235	3166235
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	1470000	1470000	1470000	1470000	1470000	1470000	1470000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	2100000	2100000	2100000	2100000	2100000	2100000	2100000
TOTAL EXPENSES	0	0	3570000	3570000	3570000	3570000	3570000	3570000	3570000
INCOME BEFORE TAXES	0	0	-403765	-403765	-403765	-403765	-403765	-403765	-403765
INVESTMENT TAX CREDIT	0	0	4200000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	4200000	3780000	3402000	3061800	2755620	2480058	2232052
TAXABLE INCOME	0	0	-2503765	-2083765	-1705765	-1365565	-1059385	-783823	-535817
CURRENT INCOME TAX	0	0	-5401807	-1000207	-818767	-655471	-508505	-376235	-257192
DEFERRED INCOME TAX	0	0	1008000	806400	624960	461664	314698	182428	63385
TOTAL INCOME TAXES	0	0	-4393807	-193807	-193807	-193807	-193807	-193807	-193807
NET INCOME (BOOK)	0	0	3990042	-209958	-209958	-209958	-209958	-209958	-209958
SOURCES OF FUNDS									
NET INCOME	0	0	3990042	-209958	-209958	-209958	-209958	-209958	-209958
FINANCIAL DEPRECIATION	0	0	2100000	2100000	2100000	2100000	2100000	2100000	2100000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	1008000	806400	624960	461664	314698	182428	63385
NET ADDITIONS TO EQUITY	21000000	21000000	0	0	0	0	0	0	0
TOTAL SOURCES	21000000	21000000	7098042	2696442	2515002	2351706	2204740	2072470	1953427
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	21000000	21000000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	21000000	21000000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	7098042	2696442	2515002	2351706	2204740	2072470	1953427
CUMULATIVE NET CASH GENERATED	0	0	7098042	9794484	12309486	14661192	16865932	18938402	20891829
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545197

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP7 GAS PROCESSING AT FAIRBANKS -250 MMSCFD -EXTRACT C2+

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY VOLUME (BBLS)	19400	19400	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	.447	.447	.447	.447	.447	.447	.447	.447	.447
TOTAL REVENUE	3166235	3166235	3166235	3166235	3166235	3166235	3166235	3166235	3166235
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	1470000	1470000	1470000	1470000	1470000	1470000	1470000	1470000	1470000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	2100000	2100000	2100000	2100000	2100000	2100000	2100000	2100000	2100000
TOTAL EXPENSES	3570000	3570000	3570000	3570000	3570000	3570000	3570000	3570000	3570000
INCOME BEFORE TAXES	-403765	-403765	-403765	-403765	-403765	-403765	-403765	-403765	-403765
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	2008847	1807962	1627166	1464449	1464449	1464449	1464449	1464449	1464449
TAXABLE INCOME	-312612	-111727	69069	231786	231786	231786	231786	231786	231786
CURRENT INCOME TAX	-150054	-53629	33153	111257	111257	111257	111257	111257	111257
DEFERRED INCOME TAX	-43753	-140178	-226960	-305064	-305064	-305064	-305064	-305064	-305064
TOTAL INCOME TAXES	-193807	-193807	-193807	-193807	-193807	-193807	-193807	-193807	-193807
NET INCOME (BOOK)	-209958	-209958	-209958	-209958	-209958	-209958	-209958	-209958	-209958
SOURCES OF FUNDS									
NET INCOME	-209958	-209958	-209958	-209958	-209958	-209958	-209958	-209958	-209958
FINANCIAL DEPRECIATION	2100000	2100000	2100000	2100000	2100000	2100000	2100000	2100000	2100000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-43753	-140178	-226960	-305064	-305064	-305064	-305064	-305064	-305064
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	1846289	1749864	1663082	1584978	1584978	1584978	1584978	1584978	1584978
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	1846289	1749864	1663082	1584978	1584978	1584978	1584978	1584978	1584978
CUMULATIVE NET CASH GENERATED	22738118	24487982	26151064	27736042	29321020	30905998	32490976	34075954	35660932
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545198

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP7 GAS PROCESSING AT FAIRBANKS -250 MMSCFD -EXTRACT C2+

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY VOLUME (BBLS)	19400	19400	19400	19400	388000	19400
COST OF SERVICE ($/BBL)	.447	.447	.447	.447	9.834	.422
TOTAL REVENUE	3166235	3166235	3166235	3166235	63324700	3166235
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	1470000	1470000	1470000	1470000	29400000	1470000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	2100000	2100000	2100000	2100000	42000000	2100000
TOTAL EXPENSES	3570000	3570000	3570000	3570000	71400000	3570000
INCOME BEFORE TAXES	-403765	-403765	-403765	-403765	-8075300	-403765
INVESTMENT TAX CREDIT	0	0	0	0	4200000	210000
TAX DEPRECIATION	1464449	1464449	1464449	1464449	41999995	2100000
TAXABLE INCOME	231786	231786	231786	231786	-8075295	-403765
CURRENT INCOME TAX	111257	111257	111257	111257	-8076144	-403807
DEFERRED INCOME TAX	-305064	-305064	-305064	-305064	4	0
TOTAL INCOME TAXES	-193807	-193807	-193807	-193807	-8076140	-403807
NET INCOME (BOOK)	-209958	-209958	-209958	-209958	840	42
SOURCES OF FUNDS						
NET INCOME	-209958	-209958	-209958	-209958	840	42
FINANCIAL DEPRECIATION	2100000	2100000	2100000	2100000	42000000	2100000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-305064	-305064	-305064	-305064	4	0
NET ADDITIONS TO EQUITY	0	0	0	0	42000000	2100000
TOTAL SOURCES	1584978	1584978	1584978	1584978	84000844	4200042
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	42000000	2100000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	42000000	2100000
NET CASH GENERATED DURING YEAR	1584978	1584978	1584978	1584978	42000844	2100042
CUMULATIVE NET CASH GENERATED	37245910	38830888	40415866	42000844	522620961	26131048
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545199

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 2149)
CASE GP8 GAS PROCESSING AT FAIRBANKS -250 MMSCFD -EXTRACT C3+

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY VOLUME (BBLS)	0	0	8900	8900	8900	8900	8900	8900	8900
COST OF SERVICE ($/BBL)	.743	.743	.743	.743	.743	.743	.743	.743	.743
TOTAL REVENUE	0	0	2412369	2412369	2412369	2412369	2412369	2412369	2412369
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	1120000	1120000	1120000	1120000	1120000	1120000	1120000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	1600000	1600000	1600000	1600000	1600000	1600000	1600000
TOTAL EXPENSES	0	0	2720000	2720000	2720000	2720000	2720000	2720000	2720000
INCOME BEFORE TAXES	0	0	-307631	-307631	-307631	-307631	-307631	-307631	-307631
INVESTMENT TAX CREDIT	0	0	3200000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	3200000	2880000	2592000	2332800	2099520	1889568	1700611
TAXABLE INCOME	0	0	-1907631	-1587631	-1299631	-1040431	-807151	-597199	-408242
CURRENT INCOME TAX	0	0	-4115663	-762063	-623823	-499407	-387432	-286655	-195956
DEFERRED INCOME TAX	0	0	768000	614400	476160	351744	239769	138992	48293
TOTAL INCOME TAXES	0	0	-3347663	-147663	-147663	-147663	-147663	-147663	-147663
NET INCOME (BOOK)	0	0	3040032	-159968	-159968	-159968	-159968	-159968	-159968
SOURCES OF FUNDS									
NET INCOME	0	0	3040032	-159968	-159968	-159968	-159968	-159968	-159968
FINANCIAL DEPRECIATION	0	0	1600000	1600000	1600000	1600000	1600000	1600000	1600000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	768000	614400	476160	351744	239769	138992	48293
NET ADDITIONS TO EQUITY	16000000	16000000	0	0	0	0	0	0	0
TOTAL SOURCES	16000000	16000000	5408032	2054432	1916192	1791776	1679801	1579024	1488325
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	16000000	16000000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	16000000	16000000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	5408032	2054432	1916192	1791776	1679801	1579024	1488325
CUMULATIVE NET CASH GENERATED	0	0	5408032	7462464	9378656	11170432	12850233	14429257	15917582
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545200

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GPB GAS PROCESSING AT FAIRBANKS -250 MMSCFD -EXTRACT C3+

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY VOLUME (BBLS)	8900	8900	8900	8900	8900	8900	8900	8900	8900
COST OF SERVICE ($/BBL)	.743	.743	.743	.743	.743	.743	.743	.743	.743
TOTAL REVENUE	2412369	2412369	2412369	2412369	2412369	2412369	2412369	2412369	2412369
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	1120000	1120000	1120000	1120000	1120000	1120000	1120000	1120000	1120000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	1600000	1600000	1600000	1600000	1600000	1600000	1600000	1600000	1600000
TOTAL EXPENSES	2720000	2720000	2720000	2720000	2720000	2720000	2720000	2720000	2720000
INCOME BEFORE TAXES	-307631	-307631	-307631	-307631	-307631	-307631	-307631	-307631	-307631
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	1530550	1377495	1239746	1115771	1115771	1115771	1115771	1115771	1115771
TAXABLE INCOME	-238181	-85126	52623	176598	176598	176598	176598	176598	176598
CURRENT INCOME TAX	-114327	-40860	25259	84767	84767	84767	84767	84767	84767
DEFERRED INCOME TAX	-33336	-105803	-172922	-232430	-232430	-232430	-232430	-232430	-232430
TOTAL INCOME TAXES	-147663	-147663	-147663	-147663	-147663	-147663	-147663	-147663	-147663
NET INCOME (BOOK)	-159968	-159968	-159968	-159968	-159968	-159968	-159968	-159968	-159968
SOURCES OF FUNDS									
NET INCOME	-159968	-159968	-159968	-159968	-159968	-159968	-159968	-159968	-159968
FINANCIAL DEPRECIATION	1600000	1600000	1600000	1600000	1600000	1600000	1600000	1600000	1600000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-33336	-105803	-172922	-232430	-232430	-232430	-232430	-232430	-232430
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	1406696	1333229	1267110	1207602	1207602	1207602	1207602	1207602	1207602
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	1406696	1333229	1267110	1207602	1207602	1207602	1207602	1207602	1207602
CUMULATIVE NET CASH GENERATED	17324278	18657507	19924617	21132219	22339821	23547423	24755025	25962627	27170229
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545201

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GPB GAS PROCESSING AT FAIRBANKS -250 MMSCFD -EXTRACT C3+

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY VOLUME (BBLS)	8900	8900	8900	8900	178000	8900
COST OF SERVICE ($/BBL)	.743	.743	.743	.743	16.346	.817
TOTAL REVENUE	2412369	2412369	2412369	2412369	48247380	2412369
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	1120000	1120000	1120000	1120000	22400000	1120000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	1600000	1600000	1600000	1600000	32000000	1600000
TOTAL EXPENSES	2720000	2720000	2720000	2720000	54400000	2720000
INCOME BEFORE TAXES	-307631	-307631	-307631	-307631	-6152620	-307631
INVESTMENT TAX CREDIT	0	0	0	0	3200000	160000
TAX DEPRECIATION	1115771	1115771	1115771	1115771	32000000	1600000
TAXABLE INCOME	176598	176598	176598	176598	-6152620	-307631
CURRENT INCOME TAX	84767	84767	84767	84767	-6153257	-307663
DEFERRED INCOME TAX	-232430	-232430	-232430	-232430	-3	0
TOTAL INCOME TAXES	-147663	-147663	-147663	-147663	-6153260	-307663
NET INCOME (BOOK)	-159968	-159968	-159968	-159968	640	32
SOURCES OF FUNDS						
NET INCOME	-159968	-159968	-159968	-159968	640	32
FINANCIAL DEPRECIATION	1600000	1600000	1600000	1600000	32000000	1600000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-232430	-232430	-232430	-232430	-3	0
NET ADDITIONS TO EQUITY	0	0	0	0	32000000	1600000
TOTAL SOURCES	1207602	1207602	1207602	1207602	64000637	3200032
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	32000000	1600000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	32000000	1600000
NET CASH GENERATED DURING YEAR	1207602	1207602	1207602	1207602	32000637	1600032
CUMULATIVE NET CASH GENERATED	28377831	29585433	30793035	32000637	398187338	19909367
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545202

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP9 GAS PROCESSING AT KENAI -250 MMSCFD -EXTRACT C2+

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY VOLUME (BBLS)	0	0	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	.330	.330	.330	.330	.330	.330	.330	.330	.330
TOTAL REVENUE	0	0	2336983	2336983	2336983	2336983	2336983	2336983	2336983
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	1085000	1085000	1085000	1085000	1085000	1085000	1085000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	1550000	1550000	1550000	1550000	1550000	1550000	1550000
TOTAL EXPENSES	0	0	2635000	2635000	2635000	2635000	2635000	2635000	2635000
INCOME BEFORE TAXES	0	0	-298017	-298017	-298017	-298017	-298017	-298017	-298017
INVESTMENT TAX CREDIT	0	0	3100000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	3100000	2790000	2511000	2259900	2033910	1830519	1647467
TAXABLE INCOME	0	0	-1848017	-1538017	-1259017	-1007917	-781927	-578536	-395484
CURRENT INCOME TAX	0	0	-3987048	-738248	-604328	-483800	-375325	-277697	-189833
DEFERRED INCOME TAX	0	0	744000	595200	461280	340752	232277	134649	46785
TOTAL INCOME TAXES	0	0	-3243048	-143048	-143048	-143048	-143048	-143048	-143048
NET INCOME (BOOK)	0	0	2945031	-154969	-154969	-154969	-154969	-154969	-154969
SOURCES OF FUNDS									
NET INCOME	0	0	2945031	-154969	-154969	-154969	-154969	-154969	-154969
FINANCIAL DEPRECIATION	0	0	1550000	1550000	1550000	1550000	1550000	1550000	1550000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	744000	595200	461280	340752	232277	134649	46785
NET ADDITIONS TO EQUITY	15500000	15500000	0	0	0	0	0	0	0
TOTAL SOURCES	15500000	15500000	5239031	1990231	1856311	1735783	1627308	1529680	1441816
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	15500000	15500000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	15500000	15500000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	5239031	1990231	1856311	1735783	1627308	1529680	1441816
CUMULATIVE NET CASH GENERATED	0	0	5239031	7229262	9085573	10821356	12448664	13978344	15420160
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

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EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP9 GAS PROCESSING AT KENAI -250 MMSCFD -EXTRACT C2+

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY VOLUME (BBLS)	19400	19400	19400	19400	19400	19400	19400	19400	19400
COST OF SERVICE ($/BBL)	.330	.330	.330	.330	.330	.330	.330	.330	.330
TOTAL REVENUE	2336983	2336983	2336983	2336983	2336983	2336983	2336983	2336983	2336983
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	1085000	1085000	1085000	1085000	1085000	1085000	1085000	1085000	1085000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	1550000	1550000	1550000	1550000	1550000	1550000	1550000	1550000	1550000
TOTAL EXPENSES	2635000	2635000	2635000	2635000	2635000	2635000	2635000	2635000	2635000
INCOME BEFORE TAXES	-298017	-298017	-298017	-298017	-298017	-298017	-298017	-298017	-298017
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	1482720	1334448	1201004	1080903	1080903	1080903	1080903	1080903	1080903
TAXABLE INCOME	-230737	-82465	50979	171080	171080	171080	171080	171080	171080
CURRENT INCOME TAX	-110754	-39584	24470	82118	82118	82118	82118	82118	82118
DEFERRED INCOME TAX	-32294	-103464	-167518	-225166	-225166	-225166	-225166	-225166	-225166
TOTAL INCOME TAXES	-143048	-143048	-143048	-143048	-143048	-143048	-143048	-143048	-143048
NET INCOME (BOOK)	-154969	-154969	-154969	-154969	-154969	-154969	-154969	-154969	-154969
SOURCES OF FUNDS									
NET INCOME	-154969	-154969	-154969	-154969	-154969	-154969	-154969	-154969	-154969
FINANCIAL DEPRECIATION	1550000	1550000	1550000	1550000	1550000	1550000	1550000	1550000	1550000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-32294	-103464	-167518	-225166	-225166	-225166	-225166	-225166	-225166
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	1362737	1291567	1227513	1169865	1169865	1169865	1169865	1169865	1169865
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	1362737	1291567	1227513	1169865	1169865	1169865	1169865	1169865	1169865
CUMULATIVE NET CASH GENERATED	16782897	18074464	19301977	20471842	21641707	22811572	23981437	25151302	26321167
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

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EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GP9 GAS PROCESSING AT KENAI -250 MMSCFD -EXTRACT C2+

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY VOLUME (BBLS)	19400	19400	19400	19400	388000	19400
COST OF SERVICE ($/BBL)	.330	.330	.330	.330	7.260	.363
TOTAL REVENUE	2336983	2336983	2336983	2336983	46739660	2336983
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	1085000	1085000	1085000	1085000	21700000	1085000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	1550000	1550000	1550000	1550000	31000000	1550000
TOTAL EXPENSES	2635000	2635000	2635000	2635000	52700000	2635000
INCOME BEFORE TAXES	-298017	-298017	-298017	-298017	-5960340	-298017
INVESTMENT TAX CREDIT	0	0	0	0	3100000	155000
TAX DEPRECIATION	1080903	1080903	1080903	1080903	30999998	1550000
TAXABLE INCOME	171080	171080	171080	171080	-5960338	-298017
CURRENT INCOME TAX	82118	82118	82118	82118	-5960967	-298048
DEFERRED INCOME TAX	-225166	-225166	-225166	-225166	7	0
TOTAL INCOME TAXES	-143048	-143048	-143048	-143048	-5960960	-298048
NET INCOME (BOOK)	-154969	-154969	-154969	-154969	620	31
SOURCES OF FUNDS						
NET INCOME	-154969	-154969	-154969	-154969	620	31
FINANCIAL DEPRECIATION	1550000	1550000	1550000	1550000	31000000	1550000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-225166	-225166	-225166	-225166	7	0
NET ADDITIONS TO EQUITY	0	0	0	0	31000000	1550000
TOTAL SOURCES	1169865	1169865	1169865	1169865	62000627	3100031
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	31000000	1550000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	31000000	1550000
NET CASH GENERATED DURING YEAR	1169865	1169865	1169865	1169865	31000627	1550031
CUMULATIVE NET CASH GENERATED	27491032	28660897	29830762	31000627	385744073	19287204
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545205

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VAA KENAI AREA 1/8 GAS -KENAI TO TOK -AFTER C2+ EXTRACTED

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	43500	43500	43500	43500	43500	43500	43500
COST OF SERVICE ($/MSCFD)	1.223	1.223	1.223	1.223	1.223	1.223	1.223	1.223	1.223
TOTAL REVENUE	0	0	19425507	19425507	19425507	19425507	19425507	19425507	19425507
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	12740000	12740000	12740000	12740000	12740000	12740000	12740000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	8276900	8276900	8276900	8276900	8276900	8276900	8276900
TOTAL EXPENSES	0	0	21016900	21016900	21016900	21016900	21016900	21016900	21016900
INCOME BEFORE TAXES	0	0	-1591393	-1591393	-1591393	-1591393	-1591393	-1591393	-1591393
INVESTMENT TAX CREDIT	0	0	16553800	0	0	0	0	0	0
TAX DEPRECIATION	0	0	16553800	14898420	13408578	12067720	10860948	9774853	8797368
TAXABLE INCOME	0	0	-9868293	-8212913	-6723071	-5382213	-4175441	-3089346	-2111861
CURRENT INCOME TAX	0	0	-21290581	-3942198	-3227074	-2583462	-2004212	-1482886	-1013693
DEFERRED INCOME TAX	0	0	3972912	3178329	2463205	1819593	1240343	719017	249824
TOTAL INCOME TAXES	0	0	-17317669	-763869	-763869	-763869	-763869	-763869	-763869
NET INCOME (BOOK)	0	0	15726276	-827524	-827524	-827524	-827524	-827524	-827524
SOURCES OF FUNDS									
NET INCOME	0	0	15726276	-827524	-827524	-827524	-827524	-827524	-827524
FINANCIAL DEPRECIATION	0	0	8276900	8276900	8276900	8276900	8276900	8276900	8276900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	3972912	3178329	2463205	1819593	1240343	719017	249824
NET ADDITIONS TO EQUITY	82769000	82769000	0	0	0	0	0	0	0
TOTAL SOURCES	82769000	82769000	27976088	10627705	9912581	9268969	8689719	8168393	7699200
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	82769000	82769000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	82769000	82769000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	27976088	10627705	9912581	9268969	8689719	8168393	7699200
CUMULATIVE NET CASH GENERATED	0	0	27976088	38603793	48516374	57785343	66475062	74643455	82342655
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545206

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VAA KENAI AREA 1/8 GAS -KENAI TO TOK -AFTER C2+ EXTRACTED

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	43500	43500	43500	43500	43500	43500	43500	43500	43500
COST OF SERVICE ($/MSCFD)	1.223	1.223	1.223	1.223	1.223	1.223	1.223	1.223	1.223
TOTAL REVENUE	19425507	19425507	19425507	19425507	19425507	19425507	19425507	19425507	19425507
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	12740000	12740000	12740000	12740000	12740000	12740000	12740000	12740000	12740000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	8276900	8276900	8276900	8276900	8276900	8276900	8276900	8276900	8276900
TOTAL EXPENSES	21016900	21016900	21016900	21016900	21016900	21016900	21016900	21016900	21016900
INCOME BEFORE TAXES	-1591393	-1591393	-1591393	-1591393	-1591393	-1591393	-1591393	-1591393	-1591393
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	7917631	7125868	6413281	5771953	5771953	5771953	5771953	5771953	5771953
TAXABLE INCOME	-1232124	-440361	272226	913554	913554	913554	913554	913554	913554
CURRENT INCOME TAX	-591420	-211373	130668	438506	438506	438506	438506	438506	438506
DEFERRED INCOME TAX	-172449	-552496	-894537	-1202375	-1202375	-1202375	-1202375	-1202375	-1202375
TOTAL INCOME TAXES	-763869	-763869	-763869	-763869	-763869	-763869	-763869	-763869	-763869
NET INCOME (BOOK)	-827524	-827524	-827524	-827524	-827524	-827524	-827524	-827524	-827524
SOURCES OF FUNDS									
NET INCOME	-827524	-827524	-827524	-827524	-827524	-827524	-827524	-827524	-827524
FINANCIAL DEPRECIATION	8276900	8276900	8276900	8276900	8276900	8276900	8276900	8276900	8276900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-172449	-552496	-894537	-1202375	-1202375	-1202375	-1202375	-1202375	-1202375
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	7276927	6896880	6554839	6247001	6247001	6247001	6247001	6247001	6247001
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	7276927	6896880	6554839	6247001	6247001	6247001	6247001	6247001	6247001
CUMULATIVE NET CASH GENERATED	89619582	96516462	103071301	109318302	115565303	121812304	128059305	134306306	140553307
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545207

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VAA KENAI AREA 1/8 GAS -KENAI TO TOK -AFTER C2+ EXTRACTED

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	43500	43500	43500	43500	870000	43500
COST OF SERVICE ($/MSCFD)	1.223	1.223	1.223	1.223	26.905	1.345
TOTAL REVENUE	19425507	19425507	19425507	19425507	388510140	19425507
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	12740000	12740000	12740000	12740000	254800000	12740000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	8276900	8276900	8276900	8276900	165538000	8276900
TOTAL EXPENSES	21016900	21016900	21016900	21016900	420338000	21016900
INCOME BEFORE TAXES	-1591393	-1591393	-1591393	-1591393	-31827860	-1591393
INVESTMENT TAX CREDIT	0	0	0	0	16553800	827690
TAX DEPRECIATION	5771953	5771953	5771953	5771953	165537997	8276900
TAXABLE INCOME	913554	913554	913554	913554	-31827857	-1591393
CURRENT INCOME TAX	438506	438506	438506	438506	-31831171	-1591559
DEFERRED INCOME TAX	-1202375	-1202375	-1202375	-1202375	-9	0
TOTAL INCOME TAXES	-763869	-763869	-763869	-763869	-31831180	-1591559
NET INCOME (BOOK)	-827524	-827524	-827524	-827524	3320	166
SOURCES OF FUNDS						
NET INCOME	-827524	-827524	-827524	-827524	3320	166
FINANCIAL DEPRECIATION	8276900	8276900	8276900	8276900	165538000	8276900
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1202375	-1202375	-1202375	-1202375	-9	0
NET ADDITIONS TO EQUITY	0	0	0	0	165538000	8276900
TOTAL SOURCES	6247001	6247001	6247001	6247001	331079311	16553966
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	165538000	8276900
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	165538000	8276900
NET CASH GENERATED DURING YEAR	6247001	6247001	6247001	6247001	165541311	8277066
CUMULATIVE NET CASH GENERATED	146800308	153047309	159294310	165541311	2059848180	102992409
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545208

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VAB KENAI AREA 1/8 GAS -KENAI TO TOK -AFTER C3+ EXTRACTED

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	47300	47300	47300	47300	47300	47300	47300
COST OF SERVICE ($/MSCFD)	1.223	1.223	1.223	1.223	1.223	1.223	1.223	1.223	1.223
TOTAL REVENUE	0	0	21118914	21118914	21118914	21118914	21118914	21118914	21118914
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	13555000	13555000	13555000	13555000	13555000	13555000	13555000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	9364400	9364400	9364400	9364400	9364400	9364400	9364400
TOTAL EXPENSES	0	0	22919400	22919400	22919400	22919400	22919400	22919400	22919400
INCOME BEFORE TAXES	0	0	-1800486	-1800486	-1800486	-1800486	-1800486	-1800486	-1800486
INVESTMENT TAX CREDIT	0	0	18728800	0	0	0	0	0	0
TAX DEPRECIATION	0	0	18728800	16855920	15170328	13653295	12287966	11059169	9953252
TAXABLE INCOME	0	0	-11164886	-9292006	-7606414	-6089381	-4724052	-3495255	-2389338
CURRENT INCOME TAX	0	0	-24087945	-4460163	-3651079	-2922903	-2267545	-1677722	-1146882
DEFERRED INCOME TAX	0	0	4494912	3595930	2786846	2058670	1403312	813489	282649
TOTAL INCOME TAXES	0	0	-19593033	-864233	-864233	-864233	-864233	-864233	-864233
NET INCOME (BOOK)	0	0	17792547	-936253	-936253	-936253	-936253	-936253	-936253
SOURCES OF FUNDS									
NET INCOME	0	0	17792547	-936253	-936253	-936253	-936253	-936253	-936253
FINANCIAL DEPRECIATION	0	0	9364400	9364400	9364400	9364400	9364400	9364400	9364400
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	4494912	3595930	2786846	2058670	1403312	813489	282649
NET ADDITIONS TO EQUITY	93644000	93644000	0	0	0	0	0	0	0
TOTAL SOURCES	93644000	93644000	31651859	12024077	11214993	10486817	9831459	9241636	8710796
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	93644000	93644000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	93644000	93644000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	31651859	12024077	11214993	10486817	9831459	9241636	8710796
CUMULATIVE NET CASH GENERATED	0	0	31651859	43675936	54890929	65377746	75209205	84450841	93161637
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545209

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VAB KENAI AREA 1/8 GAS -KENAI TO TOK -AFTER C3+ EXTRACTED

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	47300	47300	47300	47300	47300	47300	47300	47300	47300
COST OF SERVICE ($/MSCFD)	1.223	1.223	1.223	1.223	1.223	1.223	1.22	1.223	1.223
TOTAL REVENUE	21118914	21118914	21118914	21118914	21118914	21118914	21118914	21118914	21118914
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	13555000	13555000	13555000	13555000	13555000	13555000	13555000	13555000	13555000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	9364400	9364400	9364400	9364400	9364400	9364400	9364400	9364400	9364400
TOTAL EXPENSES	22919400	22919400	22919400	22919400	22919400	22919400	22919400	22919400	22919400
INCOME BEFORE TAXES	-1800486	-1800486	-1800486	-1800486	-1800486	-1800486	-1800486	-1800486	-1800486
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	8957927	8062134	7255921	6530329	6530329	6530329	6530329	6530329	6530329
TAXABLE INCOME	-1394013	-498220	307993	1033585	1033585	1033585	1033585	1033585	1033585
CURRENT INCOME TAX	-669126	-239146	147837	496121	496121	496121	496121	496121	496121
DEFERRED INCOME TAX	-195107	-625087	-1012070	-1360354	-1360354	-1360354	-1360354	-1360354	-1360354
TOTAL INCOME TAXES	-864233	-864233	-864233	-864233	-864233	-864233	-864233	-864233	-864233
NET INCOME (BOOK)	-936253	-936253	-936253	-936253	-936253	-936253	-936253	-936253	-936253
SOURCES OF FUNDS									
NET INCOME	-936253	-936253	-936253	-936253	-936253	-936253	-936253	-936253	-936253
FINANCIAL DEPRECIATION	9364400	9364400	9364400	9364400	9364400	9364400	9364400	9364400	9364400
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-195107	-625087	-1012070	-1360354	-1360354	-1360354	-1360354	-1360354	-1360354
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	8233040	7803060	7416077	7067793	7067793	7067793	7067793	7067793	7067793
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	8233040	7803060	7416077	7067793	7067793	7067793	7067793	7067793	7067793
CUMULATIVE NET CASH GENERATED	101394677	109197737	116613814	123681607	130749400	137817193	144884986	151952779	159020572
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545210

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VAB KENAI AREA 1/8 GAS -KENAI TO TOK -AFTER C3+ EXTRACTED

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	47300	47300	47300	47300	946000	47300
COST OF SERVICE ($/MSCFD)	1.223	1.223	1.223	1.223	26.906	1.345
TOTAL REVENUE	21118914	21118914	21118914	21118914	422378280	21118914
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	13555000	13555000	13555000	13555000	271100000	13555000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	9364400	9364400	9364400	9364400	187288000	9364400
TOTAL EXPENSES	22919400	22919400	22919400	22919400	458388000	22919400
INCOME BEFORE TAXES	-1800486	-1800486	-1800486	-1800486	-36009720	-1800486
INVESTMENT TAX CREDIT	0	0	0	0	18728800	936440
TAX DEPRECIATION	6530329	6530329	6530329	6530329	187288002	9364400
TAXABLE INCOME	1033585	1033585	1033585	1033585	-36009722	-1800486
CURRENT INCOME TAX	496121	496121	496121	496121	-36013464	-1800673
DEFERRED INCOME TAX	-1360354	-1360354	-1360354	-1360354	4	0
TOTAL INCOME TAXES	-864233	-864233	-864233	-864233	-36013460	-1800673
NET INCOME (BOOK)	-936253	-936253	-936253	-936253	3740	187
SOURCES OF FUNDS						
NET INCOME	-936253	-936253	-936253	-936253	3740	187
FINANCIAL DEPRECIATION	9364400	9364400	9364400	9364400	187288000	9364400
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1360354	-1360354	-1360354	-1360354	4	0
NET ADDITIONS TO EQUITY	0	0	0	0	187288000	9364400
TOTAL SOURCES	7067793	7067793	7067793	7067793	374579744	18728987
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	187288000	9364400
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	187288000	9364400
NET CASH GENERATED DURING YEAR	7067793	7067793	7067793	7067793	187291744	9364587
CUMULATIVE NET CASH GENERATED	166088365	173156158	180223951	187291744	2330491136	116524557
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545211

CASE VI

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIAA PRUDHOE 1/8 GAS -FAIRBANKS TO KENAI -BEFORE PROCESSING

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.397	.397	.397	.397	.397	.397	.397	.397	.397
TOTAL REVENUE	0	0	36231490	36231490	36231490	36231490	36231490	36231490	36231490
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	20930000	20930000	20930000	20930000	20930000	20930000	20930000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	18943800	18943800	18943800	18943800	18943800	18943800	18943800
TOTAL EXPENSES	0	0	39873800	39873800	39873800	39873800	39873800	39873800	39873800
INCOME BEFORE TAXES	0	0	-3642310	-3642310	-3642310	-3642310	-3642310	-3642310	-3642310
INVESTMENT TAX CREDIT	0	0	37887600	0	0	0	0	0	0
TAX DEPRECIATION	0	0	37887600	34098840	30688956	27620060	24858054	22372249	20135024
TAXABLE INCOME	0	0	-22586110	-18797350	-15387466	-12318570	-9556564	-7070759	-4833534
CURRENT INCOME TAX	0	0	-8728933	-9022728	-7385984	-5912914	-4587151	-3393964	-2320096
DEFERRED INCOME TAX	0	0	9093024	7274419	5637675	4164605	2838842	1645655	571787
TOTAL INCOME TAXES	0	0	-39635909	-1748309	-1748309	-1748309	-1748309	-1748309	-1748309
NET INCOME (BOOK)	0	0	35993599	-1894001	-1894001	-1894001	-1894001	-1894001	-1894001
SOURCES OF FUNDS									
NET INCOME	0	0	35993599	-1894001	-1894001	-1894001	-1894001	-1894001	-1894001
FINANCIAL DEPRECIATION	0	0	18943800	18943800	18943800	18943800	18943800	18943800	18943800
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	9093024	7274419	5637675	4164605	2838842	1645655	571787
NET ADDITIONS TO EQUITY	189438000	189438000	0	0	0	0	0	0	0
TOTAL SOURCES	189438000	189438000	64030423	24324218	22687474	21214404	19888641	18695454	17621586
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	189438000	189438000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	189438000	189438000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	64030423	24324218	22687474	21214404	19888641	18695454	17621586
CUMULATIVE NET CASH GENERATED	0	0	64030423	88354641	111042115	132256519	152145160	170840614	188462200
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545213

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIAA PRUDHOE 1/8 GAS -FAIRBANKS TO KENAI -BEFORE PROCESSING

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.397	.397	.397	.397	.397	.397	.397	.397	.397
TOTAL REVENUE	36231490	36231490	36231490	36231490	36231490	36231490	36231490	36231490	36231490
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	20930000	20930000	20930000	20930000	20930000	20930000	20930000	20930000	20930000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	18943800	18943800	18943800	18943800	18943800	18943800	18943800	18943800	18943800
TOTAL EXPENSES	39873800	39873800	39873800	39873800	39873800	39873800	39873800	39873800	39873800
INCOME BEFORE TAXES	-3642310	-3642310	-3642310	-3642310	-3642310	-3642310	-3642310	-3642310	-3642310
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	18121522	16309369	14678433	13210589	13210589	13210589	13210589	13210589	13210589
TAXABLE INCOME	-2820032	-1007879	623057	2090901	2090901	2090901	2090901	2090901	2090901
CURRENT INCOME TAX	-1353615	-483782	299068	1003632	1003632	1003632	1003632	1003632	1003632
DEFERRED INCOME TAX	-394694	-1264527	-2047377	-2751941	-2751941	-2751941	-2751941	-2751941	-2751941
TOTAL INCOME TAXES	-1748309	-1748309	-1748309	-1748309	-1748309	-1748309	-1748309	-1748309	-1748309
NET INCOME (BOOK)	-1894001	-1894001	-1894001	-1894001	-1894001	-1894001	-1894001	-1894001	-1894001
SOURCES OF FUNDS									
NET INCOME	-1894001	-1894001	-1894001	-1894001	-1894001	-1894001	-1894001	-1894001	-1894001
FINANCIAL DEPRECIATION	18943800	18943800	18943800	18943800	18943800	18943800	18943800	18943800	18943800
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-394694	-1264527	-2047377	-2751941	-2751941	-2751941	-2751941	-2751941	-2751941
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	16655105	15785272	15002422	14297858	14297858	14297858	14297858	14297858	14297858
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	16655105	15785272	15002422	14297858	14297858	14297858	14297858	14297858	14297858
CUMULATIVE NET CASH GENERATED	205117305	220902577	235904999	250202857	264500715	278798573	293096431	307394289	321692147
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545214

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE V1AA PRUDHOE 1/8 GAS -FAIRBANKS TO KENAI -BEFORE PROCESSING

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	5000000	250000
COST OF SERVICE ($/MSCFD)	.397	.397	.397	.397	8.734	.437
TOTAL REVENUE	36231490	36231490	36231490	36231490	724629800	36231490
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	20930000	20930000	20930000	20930000	418600000	20930000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	18943800	18943800	18943800	18943800	378876000	18943800
TOTAL EXPENSES	39873800	39873800	39873800	39873800	797476000	39873800
INCOME BEFORE TAXES	-3642310	-3642310	-3642310	-3642310	-72846200	-3642310
INVESTMENT TAX CREDIT	0	0	0	0	37887600	1894380
TAX DEPRECIATION	13210589	13210589	13210589	13210589	378875997	18943800
TAXABLE INCOME	2090901	2090901	2090901	2090901	-72846197	-3642310
CURRENT INCOME TAX	1003632	1003632	1003632	1003632	-72853779	-3642689
DEFERRED INCOME TAX	-2751941	-2751941	-2751941	-2751941	-1	0
TOTAL INCOME TAXES	-1748309	-1748309	-1748309	-1748309	-72853780	-3642689
NET INCOME (BOOK)	-1894001	-1894001	-1894001	-1894001	7580	379
SOURCES OF FUNDS						
NET INCOME	-1894001	-1894001	-1894001	-1894001	7580	379
FINANCIAL DEPRECIATION	18943800	18943800	18943800	18943800	378876000	18943800
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2751941	-2751941	-2751941	-2751941	-1	0
NET ADDITIONS TO EQUITY	0	0	0	0	378876000	18943800
TOTAL SOURCES	14297858	14297858	14297858	14297858	757759579	37887979
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	378876000	18943800
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	378876000	18943800
NET CASH GENERATED DURING YEAR	14297858	14297858	14297858	14297858	378883579	18944179
CUMULATIVE NET CASH GENERATED	335990005	350287863	364585721	378883579	4714488733	2357244437
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545215

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIAB PRUDHOE 1/8 GAS -KENAI TO TOK -AFTER PROCESSING

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	218000	218000	218000	218000	218000	218000	218000
COST OF SERVICE ($/MSCFD)	.457	.457	.457	.457	.457	.457	.457	.457	.457
TOTAL REVENUE	0	0	36325575	36325575	36325575	36325575	36325575	36325575	36325575
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	20940000	20940000	20940000	20940000	20940000	20940000	20940000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	19047900	19047900	19047900	19047900	19047900	19047900	19047900
TOTAL EXPENSES	0	0	39987900	39987900	39987900	39587900	39987900	39987900	39987900
INCOME BEFORE TAXES	0	0	-3662325	-3662325	-3662325	-3662325	-3662325	-3662325	-3662325
INVESTMENT TAX CREDIT	0	0	38095800	0	0	0	0	0	0
TAX DEPRECIATION	0	0	38095800	34286220	30857598	27771838	24994654	22495189	20245670
TAXABLE INCOME	0	0	-22710225	-18900645	-15472023	-12386263	-9609079	-7109614	-4860095
CURRENT INCOME TAX	0	0	-48996708	-9072310	-7426571	-5945406	-4612358	-3412615	-2332846
DEFERRED INCOME TAX	0	0	9142992	7314394	5668655	4187490	2854442	1654699	574930
TOTAL INCOME TAXES	0	0	-39853716	-1757916	-1757916	-1757916	-1757916	-1757916	-1757916
NET INCOME (BOOK)	0	0	36191391	-1904409	-1904409	-1904409	-1904409	-1904409	-1904409
SOURCES OF FUNDS									
NET INCOME	0	0	36191391	-1904409	-1904409	-1904409	-1904409	-1904409	-1904409
FINANCIAL DEPRECIATION	0	0	19047900	19047900	19047900	19047900	19047900	19047900	19047900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	9142992	7314394	5668655	4187490	2854442	1654699	574930
NET ADDITIONS TO EQUITY	190479000	190479000	0	0	0	0	0	0	0
TOTAL SOURCES	190479000	190479000	64382283	24457885	22812146	21330981	19997933	18798190	17718421
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	190479000	190479000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	190479000	190479000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	64382283	24457885	22812146	21330981	19997933	18798190	17718421
CUMULATIVE NET CASH GENERATED	0	0	64382283	88840168	111652314	132983295	152981228	171779418	189497839
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545216

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIAB PRUDHOE 1/8 GAS -KENAI TO TOK -AFTER PROCESSING

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	218000	218000	218000	218000	218000	218000	218000	218000	218000
COST OF SERVICE ($/MSCFD)	.457	.457	.457	.457	.457	.457	.457	.457	.457
TOTAL REVENUE	36325575	36325575	36325575	36325575	36325575	36325575	36325575	36325575	36325575
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	20940000	20940000	20940000	20940000	20940000	20940000	20940000	20940000	20940000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	19047900	19047900	19047900	19047900	19047900	19047900	19047900	19047900	19047900
TOTAL EXPENSES	39987900	39987900	39987900	39987900	39987900	39987900	39987900	39987900	39987900
INCOME BEFORE TAXES	-3662325	-3662325	-3662325	-3662325	-3662325	-3662325	-3662325	-3662325	-3662325
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	18221103	16398993	14759093	13283184	13283184	13283184	13283184	13283184	13283184
TAXABLE INCOME	-2835528	-1013418	626482	2102391	2102391	2102391	2102391	2102391	2102391
CURRENT INCOME TAX	-1361053	-486441	300711	1009148	1009148	1009148	1009148	1009148	1009148
DEFERRED INCOME TAX	-396863	-1271475	-2058627	-2767064	-2767064	-2767064	-2767064	-2767064	-2767064
TOTAL INCOME TAXES	-1757916	-1757916	-1757916	-1757916	-1757916	-1757916	-1757916	-1757916	-1757916
NET INCOME (BOOK)	-1904409	-1904409	-1904409	-1904409	-1904409	-1904409	-1904409	-1904409	-1904409
SOURCES OF FUNDS									
NET INCOME	-1904409	-1904409	-1904409	-1904409	-1904409	-1904409	-1904409	-1904409	-1904409
FINANCIAL DEPRECIATION	19047900	19047900	19047900	19047900	19047900	19047900	19047900	19047900	19047900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-396863	-1271475	-2058627	-2767064	-2767064	-2767064	-2767064	-2767064	-2767064
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	16746628	15872016	15084864	14376427	14376427	14376427	14376427	14376427	14376427
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	16746628	15872016	15084864	14376427	14376427	14376427	14376427	14376427	14376427
CUMULATIVE NET CASH GENERATED	206244467	222116483	237201347	251577774	265954201	280330628	294707055	309083482	323459909
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545217

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIAB PRUDHOE 1/8 GAS -KENAI TO TOK -AFTER PROCESSING

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	218000	218000	218000	218000	4360000	218000
COST OF SERVICE ($/MSCFD)	.457	.457	.457	.457	10.054	.503
TOTAL REVENUE	36325575	36325575	36325575	36325575	726511500	36325575
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	20940000	20940000	20940000	20940000	418800000	20940000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	19047900	19047900	19047900	19047900	380958000	19047900
TOTAL EXPENSES	39987900	39987900	39987900	39987900	799758000	39987900
INCOME BEFORE TAXES	-3662325	-3662325	-3662325	-3662325	-73246500	-3662325
INVESTMENT TAX CREDIT	0	0	0	0	38095800	1904790
TAX DEPRECIATION	13283184	13283184	13283184	13283184	380957998	19047900
TAXABLE INCOME	2102391	2102391	2102391	2102391	-73246498	-3662325
CURRENT INCOME TAX	1009148	1009148	1009148	1009148	-73254117	-3662706
DEFERRED INCOME TAX	-2767064	-2767064	-2767064	-2767064	-3	0
TOTAL INCOME TAXES	-1757916	-1757916	-1757916	-1757916	-73254120	-3662706
NET INCOME (BOOK)	-1904409	-1904409	-1904409	-1904409	7620	381
SOURCES OF FUNDS						
NET INCOME	-1904409	-1904409	-1904409	-1904409	7620	381
FINANCIAL DEPRECIATION	19047900	19047900	19047900	19047900	380958000	19047900
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2767064	-2767064	-2767064	-2767064	-3	0
NET ADDITIONS TO EQUITY	0	0	0	0	380958000	19047900
TOTAL SOURCES	14376427	14376427	14376427	14376427	761923617	38096181
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	380958000	19047900
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	380958000	19047900
NET CASH GENERATED DURING YEAR	14376427	14376427	14376427	14376427	380965617	19048281
CUMULATIVE NET CASH GENERATED	337836336	352212763	366589190	380965617	4740395797	237019790
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545218

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE V1BA PRUDHOE AND KENAI 1/8 GAS -KENAI TO TOK -AFTER PROCESSING

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	261400	261400	261400	261400	261400	261400	261400
COST OF SERVICE ($/MSCFD)	.415	.415	.415	.415	.415	.415	.415	.415	.415
TOTAL REVENUE	0	0	39576479	39576479	39576479	39576479	39576479	39576479	39576479
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	22500000	22500000	22500000	22500000	22500000	22500000	22500000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	21141300	21141300	21141300	21141300	21141300	21141300	21141300
TOTAL EXPENSES	0	0	43641300	43641300	43641300	43641300	43641300	43641300	43641300
INCOME BEFORE TAXES	0	0	-4064821	-4064821	-4064821	-4064821	-4064821	-4064821	-4064821
INVESTMENT TAX CREDIT	0	0	42282600	0	0	0	0	0	0
TAX DEPRECIATION	0	0	42282600	38054340	34248906	30824015	27741614	24967452	22470707
TAXABLE INCOME	0	0	-25206121	-20977861	-17172427	-13747536	-10665135	-7890973	-5394228
CURRENT INCOME TAX	0	0	-5438153B	-10069374	-8242765	-6598818	-5119265	-3787668	-2589230
DEFERRED INCOME TAX	0	0	10147824	8118260	6291651	4647704	3168151	1836554	638116
TOTAL INCOME TAXES	0	0	-44233714	-1951114	-1951114	-1951114	-1951114	-1951114	-1951114
NET INCOME (BOOK)	0	0	40168893	-2113707	-2113707	-2113707	-2113707	-2113707	-2113707
SOURCES OF FUNDS									
NET INCOME	0	0	40168893	-2113707	-2113707	-2113707	-2113707	-2113707	-2113707
FINANCIAL DEPRECIATION	0	0	21141300	21141300	21141300	21141300	21141300	21141300	21141300
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	10147824	8118260	6291651	4647704	3168151	1836554	638116
NET ADDITIONS TO EQUITY	211413000	211413000	0	0	0	0	0	0	0
TOTAL SOURCES	211413000	211413000	71458017	27145853	25319244	23675297	22195744	20864147	19665709
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	211413000	211413000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	211413000	211413000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	71458017	27145853	25319244	23675297	22195744	20864147	19665709
CUMULATIVE NET CASH GENERATED	0	0	71458017	98603870	123923114	147598411	169794155	190658302	210324011
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545219

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIBA PRUDHOE AND KENAI 1/8 GAS -KENAI TO TOK -AFTER PROCESSING

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	261400	261400	261400	261400	261400	261400	261400	261400	261400
COST OF SERVICE ($/MSCFD)	.415	.415	.415	.415	.415	.415	.415	.415	.415
TOTAL REVENUE	39576479	39576479	39576479	39576479	39576479	39576479	39576479	39576479	39576479
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	22500000	22500000	22500000	22500000	22500000	22500000	22500000	22500000	22500000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	21141300	21141300	21141300	21141300	21141300	21141300	21141300	21141300	21141300
TOTAL EXPENSES	43641300	43641300	43641300	43641300	43641300	43641300	43641300	43641300	43641300
INCOME BEFORE TAXES	-4064821	-4064821	-4064821	-4064821	-4064821	-4064821	-4064821	-4064821	-4064821
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	20223637	18201273	16381146	14743031	14743031	14743031	14743031	14743031	14743031
TAXABLE INCOME	-3147158	-1124794	695333	2333448	2333448	2333448	2333448	2333448	2333448
CURRENT INCOME TAX	-1510636	-539901	333760	1120055	1120055	1120055	1120055	1120055	1120055
DEFERRED INCOME TAX	-440478	-1411213	-2284874	-3071169	-3071169	-3071169	-3071169	-3071169	-3071169
TOTAL INCOME TAXES	-1951114	-1951114	-1951114	-1951114	-1951114	-1951114	-1951114	-1951114	-1951114
NET INCOME (BOOK)	-2113707	-2113707	-2113707	-2113707	-2113707	-2113707	-2113707	-2113707	-2113707
SOURCES OF FUNDS									
NET INCOME	-2113707	-2113707	-2113707	-2113707	-2113707	-2113707	-2113707	-2113707	-2113707
FINANCIAL DEPRECIATION	21141300	21141300	21141300	21141300	21141300	21141300	21141300	21141300	21141300
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-440478	-1411213	-2284874	-3071169	-3071169	-3071169	-3071169	-3071169	-3071169
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	18587115	17616380	16742719	15956424	15956424	15956424	15956424	15956424	15956424
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	18587115	17616390	16742719	15956424	15956424	15956424	15956424	15956424	15956424
CUMULATIVE NET CASH GENERATED	228911126	246527505	263270225	279226649	295183073	311139497	327095921	343052345	359008769
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545220

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE V18A PRUDHOE AND KENAI 1/8 GAS -KENAI TO TOK -AFTER PROCESSING

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	261400	261400	261400	261400	5228000	261400
COST OF SERVICE (¢/MSCFD)	.415	.415	.415	.415	9.130	.457
TOTAL REVENUE	39576479	39576479	39576479	39576479	791529580	39576479
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	22500000	22500000	22500000	22500000	450000000	22500000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	21141300	21141300	21141300	21141300	422826000	21141300
TOTAL EXPENSES	43641300	43641300	43641300	43641300	872826000	43641300
INCOME BEFORE TAXES	-4064821	-4064821	-4064821	-4064821	-81296420	-4064821
INVESTMENT TAX CREDIT	0	0	0	0	42282600	2114130
TAX DEPRECIATION	14743031	14743031	14743031	14743031	422826000	21141300
TAXABLE INCOME	2333448	2333448	2333448	2333448	-81296420	-4064821
CURRENT INCOME TAX	1120055	1120055	1120055	1120055	-81304885	-4065244
DEFERRED INCOME TAX	-3071169	-3071169	-3071169	-3071169	5	0
TOTAL INCOME TAXES	-1951114	-1951114	-1951114	-1951114	-81304880	-4065244
NET INCOME (BOOK)	-2113707	-2113707	-2113707	-2113707	8460	423
SOURCES OF FUNDS						
NET INCOME	-2113707	-2113707	-2113707	-2113707	8460	423
FINANCIAL DEPRECIATION	21141300	21141300	21141300	21141300	422826000	21141300
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-3071169	-3071169	-3071169	-3071169	5	0
NET ADDITIONS TO EQUITY	0	0	0	0	422826000	21141300
TOTAL SOURCES	15956424	15956424	15956424	15956424	845660465	42283023
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	422826000	21141300
LONG TERM DEPT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	422826000	21141300
NET CASH GENERATED DURING YEAR	15956424	15956424	15956424	15956424	422834465	21141723
CUMULATIVE NET CASH GENERATED	374965193	390921617	406878041	422834465	5261374307	263068715
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545221

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VICA PRUDHOE 1/8 GAS -TOK TO KENAI -BEFORE PROCESSING

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.383	.383	.383	.383	.383	.383	.383	.383	.383
TOTAL REVENUE	0	0	34991330	34991330	34991330	34991330	34991330	34991330	34991330
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	20300000	20300000	20300000	20300000	20300000	20300000	20300000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	18188400	18188400	18188400	18188400	18188400	18188400	18188400
TOTAL EXPENSES	0	0	38488400	38488400	38488400	38488400	38488400	38488400	38488400
INCOME BEFORE TAXES	0	0	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070
INVESTMENT TAX CREDIT	0	0	36376800	0	0	0	0	0	0
TAX DEPRECIATION	0	0	36376800	32739120	29465208	26518687	23866818	21480137	19332123
TAXABLE INCOME	0	0	-21685470	-18047790	-14773878	-11827357	-9175488	-6788807	-4640793
CURRENT INCOME TAX	0	0	-46785825	-8662939	-7091461	-5677131	-4404234	-3258627	-2227580
DEFERRED INCOME TAX	0	0	8730432	6984346	5412868	3998538	2725641	1580034	548987
TOTAL INCOME TAXES	0	0	-38055393	-1678593	-1678593	-1678593	-1678593	-1678593	-1678593
NET INCOME (BOOK)	0	0	34558323	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477
SOURCES OF FUNDS									
NET INCOME	0	0	34558323	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477
FINANCIAL DEPRECIATION	0	0	18188400	18188400	18188400	18188400	18188400	18188400	18188400
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	8730432	6984346	5412868	3998538	2725641	1580034	548987
NET ADDITIONS TO EQUITY	181884000	181884000	0	0	0	0	0	0	0
TOTAL SOURCES	181884000	181884000	61477155	23354269	21782791	20368461	19095564	17949957	16918910
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	181884000	181884000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	181884000	181884000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	61477155	23354269	21782791	20368461	19095564	17949957	16918910
CUMULATIVE NET CASH GENERATED	0	0	61477155	84831424	106614215	126982676	146078240	164028197	180947107
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545222

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VICA PRUDHOE 1/8 GAS -TOK TO KENAI -BEFORE PROCESSING

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.383	.383	.383	.383	.383	.383	.383	.383	.383
TOTAL REVENUE	34991330	34991330	34991330	34991330	34991330	34991330	34991330	34991330	34991330
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	20300000	20300000	20300000	20300000	20300000	20300000	20300000	20300000	20300000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	18188400	18188400	18188400	18188400	18188400	18188400	18188400	18188400	18188400
TOTAL EXPENSES	38488400	38488400	38488400	38488400	38488400	38488400	38488400	38488400	38488400
INCOME BEFORE TAXES	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	17398911	15659020	14093118	12683806	12683806	12683806	12683806	12683806	12683806
TAXABLE INCOME	-2707581	-967690	598212	2007524	2007524	2007524	2007524	2007524	2007524
CURRENT INCOME TAX	-1299639	-464491	287142	963612	963612	963612	963612	963612	963612
DEFERRED INCOME TAX	-378954	-1214102	-1965735	-2642205	-2642205	-2642205	-2642205	-2642205	-2642205
TOTAL INCOME TAXES	-1678593	-1678593	-1678593	-1678593	-1678593	-1678593	-1678593	-1678593	-1678593
NET INCOME (BOOK)	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477
SOURCES OF FUNDS									
NET INCOME	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477
FINANCIAL DEPRECIATION	18188400	18188400	18188400	18188400	18188400	18188400	18188400	18188400	18188400
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-378954	-1214102	-1965735	-2642205	-2642205	-2642205	-2642205	-2642205	-2642205
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	15990969	15155821	14404188	13727718	13727718	13727718	13727718	13727718	13727718
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	15990969	15155821	14404188	13727718	13727718	13727718	13727718	13727718	13727718
CUMULATIVE NET CASH GENERATED	196938076	212093897	226498085	240225803	253953521	267681239	281408957	295136675	308864393
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545223

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VICA PRUDHOE 1/8 GAS -TOK TO KENAI -BEFORE PROCESSING

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	5000000	250000
COST OF SERVICE (¢/MSCFD)	.383	.383	.383	.383	8.426	.421
TOTAL REVENUE	34991330	34991330	34991330	34991330	699826600	34991330
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	20300000	20300000	20300000	20300000	406000000	20300000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	18188400	18188400	18188400	18188400	363768000	18188400
TOTAL EXPENSES	38488400	38488400	38488400	38488400	769768000	38488400
INCOME BEFORE TAXES	-3497070	-3497070	-3497070	-3497070	-69941400	-3497070
INVESTMENT TAX CREDIT	0	0	0	0	36376800	1818840
TAX DEPRECIATION	12683806	12683806	12683806	12683806	363768002	18188400
TAXABLE INCOME	2007524	2007524	2007524	2007524	-69941402	-3497070
CURRENT INCOME TAX	963612	963612	963612	963612	-69948665	-3497433
DEFERRED INCOME TAX	-2642205	-2642205	-2642205	-2642205	5	0
TOTAL INCOME TAXES	-1678593	-1678593	-1678593	-1678593	-69948660	-3497433
NET INCOME (BOOK)	-1818477	-1818477	-1818477	-1818477	7260	363
SOURCES OF FUNDS						
NET INCOME	-1818477	-1818477	-1818477	-1818477	7260	363
FINANCIAL DEPRECIATION	18188400	18188400	18188400	18188400	363768000	18188400
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2642205	-2642205	-2642205	-2642205	5	0
NET ADDITIONS TO EQUITY	0	0	0	0	363768000	18188400
TOTAL SOURCES	13727718	13727718	13727718	13727718	727543265	36377163
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	363768000	18188400
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	363768000	18188400
NET CASH GENERATED DURING YEAR	13727718	13727718	13727718	13727718	363775265	18188763
CUMULATIVE NET CASH GENERATED	322592111	336319829	350047547	363775265	4526494412	226324721
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.60

AGO 545224

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VICB PRUDHOE 1/8 GAS -KENAI TO TOK -AFTER PROCESSING

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	218000	218000	218000	218000	218000	218000	218000
COST OF SERVICE ($/MSCFD)	.440	.440	.440	.440	.440	.440	.440	.440	.440
TOTAL REVENUE	0	0	34991330	34991330	34991330	34991330	34991330	34991330	34991330
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	20300000	20300000	20300000	20300000	20300000	20300000	20300000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	18188400	18188400	18188400	18188400	18188400	18188400	18188400
TOTAL EXPENSES	0	0	38488400	38488400	38488400	38488400	38488400	38488400	38488400
INCOME BEFORE TAXES	0	0	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070
INVESTMENT TAX CREDIT	0	0	36376800	0	0	0	0	0	0
TAX DEPRECIATION	0	0	36376800	32739120	29465208	26518687	23866818	21480137	19332123
TAXABLE INCOME	0	0	-21685470	-18047790	-14773878	-11827357	-9175488	-6788807	-4640793
CURRENT INCOME TAX	0	0	-46785825	-8662939	-7091461	-5677131	-4404234	-3258627	-2227580
DEFERRED INCOME TAX	0	0	8730432	6984346	5412868	3998538	2725641	1580034	548987
TOTAL INCOME TAXES	0	0	-38055393	-1678593	-1678593	-1678593	-1678593	-1678593	-1678593
NET INCOME (BOOK)	0	0	34558323	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477
SOURCES OF FUNDS									
NET INCOME	0	0	34558323	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477
FINANCIAL DEPRECIATION	0	0	18188400	18188400	18188400	18188400	18188400	18188400	18188400
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	8730432	6984346	5412868	3998538	2725641	1580034	548987
NET ADDITIONS TO EQUITY	181884000	181884000	0	0	0	0	0	0	0
TOTAL SOURCES	181884000	181884000	61477155	23354269	21782791	20368461	19095564	17949957	16918910
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	181884000	181884000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	181884000	181884000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	61477155	23354269	21782791	20368461	19095564	17949957	16918910
CUMULATIVE NET CASH GENERATED	0	0	61477155	84831424	106614215	126982676	146078240	164028197	180947107
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545225

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VICB PRUDHOE 1/8 GAS -KENAI TO TOK -AFTER PROCESSING

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	218000	218000	218000	218000	218000	218000	218000	218000	218000
COST OF SERVICE ($/MSCFD)	.440	.440	.440	.440	.440	.440	.440	.440	.440
TOTAL REVENUE	34991330	34991330	34991330	34991330	34991330	34991330	34991330	34991330	34991330
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	20300000	20300000	20300000	20300000	20300000	20300000	20300000	20300000	20300000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	18188400	18188400	18188400	18188400	18188400	18188400	18188400	18188400	18188400
TOTAL EXPENSES	38488400	38488400	38488400	38488400	38488400	38488400	38488400	38488400	38488400
INCOME BEFORE TAXES	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070	-3497070
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	17398911	15659020	14093118	12683806	12683806	12683806	12683806	12683806	12683806
TAXABLE INCOME	-2707581	-967690	598212	2007524	2007524	2007524	2007524	2007524	2007524
CURRENT INCOME TAX	-1299639	-464491	287142	963612	963612	963612	963612	963612	963612
DEFERRED INCOME TAX	-378954	-1214102	-1965735	-2642205	-2642205	-2642205	-2642205	-2642205	-2642205
TOTAL INCOME TAXES	-1678593	-1678593	-1678593	-1678593	-1678593	-1678593	-1678593	-1678593	-1678593
NET INCOME (BOOK)	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477
SOURCES OF FUNDS									
NET INCOME	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477	-1818477
FINANCIAL DEPRECIATION	18188400	18188400	18188400	18188400	18188400	18188400	18188400	18188400	18188400
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-378954	-1214102	-1965735	-2642205	-2642205	-2642205	-2642205	-2642205	-2642205
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	15990969	15155821	14404188	13727718	13727718	13727718	13727718	13727718	13727718
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	15990969	15155821	14404188	13727718	13727718	13727718	13727718	13727718	13727718
CUMULATIVE NET CASH GENERATED	196938076	212093897	226498085	240225803	253953521	267681239	281408957	295136675	308864393
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545226

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VICB PRUDHOE 1/8 GAS -KENAI TO TOK -AFTER PROCESSING

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	218000	218000	218000	218000	4360000	218000
COST OF SERVICE ($/MSCFD)	.440	.440	.440	.440	9.080	.484
TOTAL REVENUE	34991330	34991330	34991330	34991330	699826600	34991330
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	20300000	20300000	20300000	20300000	406000000	20300000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	18188400	18188400	18188400	18188400	363768000	18188400
TOTAL EXPENSES	38488400	38488400	38488400	38488400	769768000	38488400
INCOME BEFORE TAXES	-3497070	-3497070	-3497070	-3497070	-69941400	-3497070
INVESTMENT TAX CREDIT	0	0	0	0	36376800	1818840
TAX DEPRECIATION	12683806	12683806	12683806	12683806	363768002	18188400
TAXABLE INCOME	2007524	2007524	2007524	2007524	-69941402	-3497079
CURRENT INCOME TAX	963612	963612	963612	963612	-69948665	-3497433
DEFERRED INCOME TAX	-2642205	-2642205	-2642205	-2642205	5	0
TOTAL INCOME TAXES	-1678593	-1678593	-1678593	-1678593	-69948660	-3497433
NET INCOME (BOOK)	-1818477	-1818477	-1818477	-1818477	7260	363
SOURCES OF FUNDS						
NET INCOME	-1818477	-1818477	-1818477	-1818477	7260	363
FINANCIAL DEPRECIATION	18188400	18188400	18188400	18188400	363768000	18188400
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2642205	-2642205	-2642205	-2642205	5	0
NET ADDITIONS TO EQUITY	0	0	0	0	363768000	18188400
TOTAL SOURCES	13727718	13727718	13727718	13727718	727543265	36377163
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	363768000	18188400
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	363768000	18188400
NET CASH GENERATED DURING YEAR	13727718	13727718	13727718	13727718	363775265	18188763
CUMULATIVE NET CASH GENERATED	322592111	336319829	350047547	363775265	4526494412	226324721
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545227

CASE VII

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA1 PRUDHOE 1/8 GAS -FAIRBANKS TO HAINES -NO PROCESSING

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.614	.614	.614	.614	.614	.614	.614	.614	.614
TOTAL REVENUE	0	0	56023664	56023664	56023664	56023664	56023664	56023664	56023664
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	31100000	31100000	31100000	31100000	31100000	31100000	31100000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	30856400	30856400	30856400	30856400	30856400	30856400	30856400
TOTAL EXPENSES	0	0	61956400	61956400	61956400	61956400	61956400	61956400	61956400
INCOME BEFORE TAXES	0	0	-5932736	-5932736	-5932736	-5932736	-5932736	-5932736	-5932736
INVESTMENT TAX CREDIT	0	0	61712800	0	0	0	0	0	0
TAX DEPRECIATION	0	0	61712800	55541520	49987368	44988631	40489768	36440791	32796712
TAXABLE INCOME	0	0	-36789136	-30617856	-25063704	-20064967	-15566104	-11517127	-7873048
CURRENT INCOME TAX	0	0	-79371585	-14696571	-12030578	-9631184	-7471730	-5528221	-3779063
DEFERRED INCOME TAX	0	0	14811072	11848858	9182865	6783471	4624017	2680506	931350
TOTAL INCOME TAXES	0	0	-64560513	-2847713	-2847713	-2847713	-2847713	-2847713	-2847713
NET INCOME (BOOK)	0	0	58627777	-3085023	-3085023	-3085023	-3085023	-3085023	-3085023
SOURCES OF FUNDS									
NET INCOME	0	0	58627777	-3085023	-3085023	-3085023	-3085023	-3085023	-3085023
FINANCIAL DEPRECIATION	0	0	30856400	30856400	30856400	30856400	30856400	30856400	30856400
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	14811072	11848858	9182865	6783471	4624017	2680508	931350
NET ADDITIONS TO EQUITY	308564000	308564000	0	0	0	0	0	0	0
TOTAL SOURCES	308564000	308564000	104295249	39620235	36954242	34554848	32395394	30451885	28702727
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	308564000	308564000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	308564000	308564000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	104295249	39620235	36954242	34554848	32395394	30451885	28702727
CUMULATIVE NET CASH GENERATED	0	0	104295249	143915484	180869726	215424574	247819968	278271853	306974580
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545229

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA1 PRUDHOE 1/8 GAS -FAIRBANKS TO HAINES -NO PROCESSING

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.614	.614	.614	.614	.614	.614	.614	.614	.614
TOTAL REVENUE	56023664	56023664	56023664	56023664	56023664	56023664	56023664	56023664	56023664
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	31100000	31100000	31100000	31100000	31100000	31100000	31100000	31100000	31100000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	30856400	30856400	30856400	30856400	30856400	30856400	30856400	30856400	30856400
TOTAL EXPENSES	61956400	61956400	61956400	61956400	61956400	61956400	61956400	61956400	61956400
INCOME BEFORE TAXES	-5932736	-5932736	-5932736	-5932736	-5932736	-5932736	-5932736	-5932736	-5932736
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	29517041	26565337	23908803	21517923	21517923	21517923	21517923	21517923	21517923
TAXABLE INCOME	-4593377	-1641673	1014061	3405741	3405741	3405741	3405741	3405741	3405741
CURRENT INCOME TAX	-2204821	-788003	487133	1634756	1634756	1634756	1634756	1634756	1634756
DEFERRED INCOME TAX	-642892	-2059710	-3334846	-4482469	-4482469	-4482469	-4482469	-4482469	-4482469
TOTAL INCOME TAXES	-2847713	-2847713	-2847713	-2847713	-2847713	-2847713	-2847713	-2847713	-2847713
NET INCOME (BOOK)	-3085023	-3085023	-3085023	-3085023	-3085023	-3085023	-3085023	-3085023	-3085023
SOURCES OF FUNDS									
NET INCOME	-3085023	-3085023	-3085023	-3085023	-3085023	-3085023	-3085023	-3085023	-3085023
FINANCIAL DEPRECIATION	30856400	30856400	30856400	30856400	30856400	30856400	30856400	30856400	30856400
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-642892	-2059710	-3334846	-4482469	-4482469	-4482469	-4482469	-4482469	-4482469
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	27128485	25711667	24436531	23288908	23288908	23288908	23288908	23288908	23288908
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	27128485	25711667	24436531	23288908	23288908	23288908	23288908	23288908	23288908
CUMULATIVE NET CASH GENERATED	334103065	359814732	384251263	407540171	430829079	454117987	477406895	500695803	523984711
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545230

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA1 PRUDHOE 1/8 GAS -FAIRBANKS TO HAINES -NO PROCESSING

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	5000000	250000
COST OF SERVICE ($/MSCFD)	.614	.614	.614	.614	13.509	.675
TOTAL REVENUE	56023664	56023664	56023664	56023664	1120473280	56023664
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	31100000	31100000	31100000	31100000	622000000	31100000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	30856400	30856400	30856400	30856400	617128000	30856400
TOTAL EXPENSES	61956400	61956400	61956400	61956400	1239128000	61956400
INCOME BEFORE TAXES	-5932736	-5932736	-5932736	-5932736	-118654720	-5932736
INVESTMENT TAX CREDIT	0	0	0	0	61712800	3085640
TAX DEPRECIATION	21517923	21517923	21517923	21517923	617128001	30856400
TAXABLE INCOME	3405741	3405741	3405741	3405741	-118654721	-5932736
CURRENT INCOME TAX	1634756	1634756	1634756	1634756	-118667063	-5933353
DEFERRED INCOME TAX	-4482469	-4482469	-4482469	-4482469	3	0
TOTAL INCOME TAXES	-2847713	-2847713	-2847713	-2847713	-118667060	-5933353
NET INCOME (BOOK)	-3085023	-3085023	-3085023	-3085023	12340	617
SOURCES OF FUNDS						
NET INCOME	-3085023	-3085023	-3085023	-3085023	12340	617
FINANCIAL DEPRECIATION	30856400	30856400	30856400	30856400	617128000	30856400
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-4482469	-4482469	-4482469	-4482469	3	0
NET ADDITIONS TO EQUITY	0	0	0	0	617128000	30856400
TOTAL SOURCES	23288908	23288908	23288908	23288908	1234268343	61713417
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	617128000	30856400
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	617128000	30856400
NET CASH GENERATED DURING YEAR	23288908	23288908	23288908	23288908	617140343	30857017
CUMULATIVE NET CASH GENERATED	547273619	570562527	593851435	617140343	37679143064	38395153
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545231

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA2 PRUDHOE 1/8 GAS -HAINES JCT. TO HAINES -NO PROCESSING

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.114	.114	.114	.114	.114	.114	.114	.114	.114
TOTAL REVENUE	0	0	10369528	10369528	10369528	10369528	10369528	10369528	10369528
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	5830000	5830000	5830000	5830000	5830000	5830000	5830000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	5620100	5620100	5620100	5620100	5620100	5620100	5620100
TOTAL EXPENSES	0	0	11450100	11450100	11450100	11450100	11450100	11450100	11450100
INCOME BEFORE TAXES	0	0	-1080572	-1080572	-1080572	-1080572	-1080572	-1080572	-1080572
INVESTMENT TAX CREDIT	0	0	11240200	0	0	0	0	0	0
TAX DEPRECIATION	0	0	11240200	10116180	9104562	8194106	7374695	6637226	5973503
TAXABLE INCOME	0	0	-6700672	-5576652	-4565034	-3654578	-2835167	-2097698	-1433975
CURRENT INCOME TAX	0	0	-14456523	-2676793	-2191216	-1754197	-1360880	-1006895	-688308
DEFERRED INCOME TAX	0	0	2697648	2158118	1672541	1235522	842205	488220	169633
TOTAL INCOME TAXES	0	0	-11758875	-518675	-518675	-518675	-518675	-518675	-518675
NET INCOME (BOOK)	0	0	10678303	-561897	-561897	-561897	-561897	-561897	-561897
SOURCES OF FUNDS									
NET INCOME	0	0	10678303	-561897	-561897	-561897	-561897	-561897	-561897
FINANCIAL DEPRECIATION	0	0	5620100	5620100	5620100	5620100	5620100	5620100	5620100
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	2697648	2158118	1672541	1235522	842205	488220	169633
NET ADDITIONS TO EQUITY	56201000	56201000	0	0	0	0	0	0	0
TOTAL SOURCES	56201000	56201000	18996051	7216321	6730744	6293725	5900408	5546423	5227836
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	56201000	56201000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	56201000	56201000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	18996051	7216321	6730744	6293725	5900408	5546423	5227836
CUMULATIVE NET CASH GENERATED	0	0	18996051	26212372	32943116	39236841	45137249	50683672	55911508
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545232

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA2 PRUDHOE 1/8 GAS -HAINES JCT. TO HAINES -NO PROCESSING

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.114	.114	.114	.114	.114	.114	.114	.114	.114
TOTAL REVENUE	10369528	10369528	10369528	10369528	10369528	10369528	10369528	10369528	10369528
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	5830000	5830000	5830000	5830000	5830000	5830000	5830000	5830000	5830000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	5620100	5620100	5620100	5620100	5620100	5620100	5620100	5620100	5620100
TOTAL EXPENSES	11450100	11450100	11450100	11450100	11450100	11450100	11450100	11450100	11450100
INCOME BEFORE TAXES	-1080572	-1080572	-1080572	-1080572	-1080572	-1080572	-1080572	-1080572	-1080572
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	5376153	4838538	4354684	3919215	3919215	3919215	3919215	3919215	3919215
TAXABLE INCOME	-836625	-299010	184844	620313	620313	620313	620313	620313	620313
CURRENT INCOME TAX	-401580	-143525	88725	297750	297750	297750	297750	297750	297750
DEFERRED INCOME TAX	-117095	-375150	-607400	-816425	-816425	-816425	-816425	-816425	-816425
TOTAL INCOME TAXES	-518675	-518675	-518675	-518675	-518675	-518675	-518675	-518675	-518675
NET INCOME (BOOK)	-561897	-561897	-561897	-561897	-561897	-561897	-561897	-561897	-561897
SOURCES OF FUNDS									
NET INCOME	-561897	-561897	-561897	-561897	-561897	-561897	-561897	-561897	-561897
FINANCIAL DEPRECIATION	5620100	5620100	5620100	5620100	5620100	5620100	5620100	5620100	5620100
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-117095	-375150	-607400	-816425	-816425	-816425	-816425	-816425	-816425
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	4941108	4683053	4450803	4241778	4241778	4241778	4241778	4241778	4241778
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	4941108	4683053	4450803	4241778	4241778	4241778	4241778	4241778	4241778
CUMULATIVE NET CASH GENERATED	60852616	65535669	69986472	74228250	78470028	82711806	86953584	91195362	95437140
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545233

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA2 PRUDHOE 1/8 GAS -HAINES JCT. TO HAINES -NO PROCESSING

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	5000000	250000
COST OF SERVICE ($/MSCFD)	.114	.114	.114	.114	2.508	.125
TOTAL REVENUE	10369528	10369528	10369528	10369528	207390560	10369528
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	5830000	5830000	5830000	5830000	116600000	5830000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	5620100	5620100	5620100	5620100	112402000	5620100
TOTAL EXPENSES	11450100	11450100	11450100	11450100	229002000	11450100
INCOME BEFORE TAXES	-1080572	-1080572	-1080572	-1080572	-21611440	-1080572
INVESTMENT TAX CREDIT	0	0	0	0	11240200	562010
TAX DEPRECIATION	3919215	3919215	3919215	3919215	112401597	5620100
TAXABLE INCOME	620313	620313	620313	620313	-21611437	-1080572
CURRENT INCOME TAX	297750	297750	297750	297750	-21613692	-1080685
DEFERRED INCOME TAX	-816425	-816425	-816425	-816425	-8	0
TOTAL INCOME TAXES	-518675	-518675	-518675	-518675	-21613700	-1080685
NET INCOME (BOOK)	-561897	-561897	-561897	-561897	2260	113
SOURCES OF FUNDS						
NET INCOME	-561897	-561897	-561897	-561897	2260	113
FINANCIAL DEPRECIATION	5620100	5620100	5620100	5620100	112402000	5620100
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-816425	-816425	-816425	-816425	-8	0
NET ADDITIONS TO EQUITY	0	0	0	0	112402000	5620100
TOTAL SOURCES	4241778	4241778	4241778	4241778	224806252	11240313
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	112402000	5620100
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	112402000	5620100
NET CASH GENERATED DURING YEAR	4241778	4241778	4241778	4241778	112404252	5620213
CUMULATIVE NET CASH GENERATED	99678918	103920696	108162474	112404252	139658076	69932904
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545234

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA4 KENAI 1/8 GAS -KENAI TO TOK -NO PROCESSING

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	50000	50000	50000	50000	50000	50000	50000
COST OF SERVICE ($/MSCFD)	1.155	1.155	1.155	1.155	1.155	1.155	1.155	1.155	1.155
TOTAL REVENUE	0	0	21085094	21085094	21085094	21085094	21085094	21085094	21085094
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	13540000	13540000	13540000	13540000	13540000	13540000	13540000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	9341100	9341100	9341100	9341100	9341100	9341100	9341100
TOTAL EXPENSES	0	0	22881100	22881100	22881100	22881100	22881100	22881100	22881100
INCOME BEFORE TAXES	0	0	-1796006	-1796006	-1796006	-1796006	-1796006	-1796006	-1796006
INVESTMENT TAX CREDIT	0	0	18682200	0	0	0	0	0	0
TAX DEPRECIATION	0	0	18682200	16813980	15132582	13619324	12257391	11031652	9928487
TAXABLE INCOME	0	0	-11137106	-9268886	-7587488	-6074230	-4712297	-3486558	-2383393
CURRENT INCOME TAX	0	0	-24028011	-4449065	-3641994	-2915630	-2261903	-1673548	-1144029
DEFERRED INCOME TAX	0	0	4483728	3586982	2779911	2053547	1399820	811465	281946
TOTAL INCOME TAXES	0	0	-19544283	-862083	-862083	-862083	-862083	-862083	-862083
NET INCOME (BOOK)	0	0	17748277	-933923	-933923	-933923	-933923	-933923	-933923
SOURCES OF FUNDS									
NET INCOME	0	0	17748277	-933923	-933923	-933923	-933923	-933923	-933923
FINANCIAL DEPRECIATION	0	0	9341100	9341100	9341100	9341100	9341100	9341100	9341100
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	4483728	3586982	2779911	2053547	1399820	811465	281946
NET ADDITIONS TO EQUITY	93411000	93411000	0	0	0	0	0	0	0
TOTAL SOURCES	93411000	93411000	31573105	11994159	11187088	10460724	9806997	9218642	8689123
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	93411000	93411000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	93411000	93411000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	31573105	11994159	11187088	10460724	9806997	9218642	8689123
CUMULATIVE NET CASH GENERATED	0	0	31573105	43567264	54754352	65215076	75022073	84240715	92929838
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545235

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA4 KENAI 1/8 GAS -KENAI TO TOK -NO PROCESSING

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	50000	50000	50000	50000	50000	50000	50000	50000	50000
COST OF SERVICE ($/MSCFD)	1.155	1.155	1.155	1.155	1.155	1.155	1.155	1.155	1.155
TOTAL REVENUE	21085094	21085094	21085094	21085094	21085094	21085094	21085094	21085094	21085094
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	13540000	13540000	13540000	13540000	13540000	13540000	13540000	13540000	13540000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	9341100	9341100	9341100	9341100	9341100	9341100	9341100	9341100	9341100
TOTAL EXPENSES	22881100	22881100	22881100	22881100	22881100	22881100	22881100	22881100	22881100
INCOME BEFORE TAXES	-1796006	-1796006	-1796006	-1796006	-1796006	-1796006	-1796006	-1796006	-1796006
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	8935638	8042075	7237867	6514080	6514080	6514080	6514080	6514080	6514080
TAXABLE INCOME	-1390544	-496981	307227	1031014	1031014	1031014	1031014	1031014	1031014
CURRENT INCOME TAX	-667461	-238551	147469	494886	494886	494886	494886	494886	494886
DEFERRED INCOME TAX	-194622	-623532	-1009552	-1356969	-1356969	-1356969	-1356969	-1356969	-1356969
TOTAL INCOME TAXES	-862083	-862083	-862083	-862083	-862083	-862083	-862083	-862083	-862083
NET INCOME (BOOK)	-933923	-933923	-933923	-933923	-933923	-933923	-933923	-933923	-933923
SOURCES OF FUNDS									
NET INCOME	-933923	-933923	-933923	-933923	-933923	-933923	-933923	-933923	-933923
FINANCIAL DEPRECIATION	9341100	9341100	9341100	9341100	9341100	9341100	9341100	9341100	9341100
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-194622	-623532	-1009552	-1356969	-1356969	-1356969	-1356969	-1356969	-1356969
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	8212555	7783645	7397625	7050208	7050208	7050208	7050208	7050208	7050208
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	8212555	7783645	7397625	7050208	7050208	7050208	7050208	7050208	7050208
CUMULATIVE NET CASH GENERATED	101142393	108926038	116323663	123373871	130424079	137474287	144524495	151574703	158624911
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545236

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA4 KENAI 1/8 GAS -KENAI TO TOK -NO PROCESSING

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	50000	50000	50000	50000	1000000	50000
COST OF SERVICE ($/MSCFD)	1.155	1.155	1.155	1.155	25.410	1.271
TOTAL REVENUE	21085094	21085094	21085094	21085094	421701680	21085094
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	13540000	13540000	13540000	13540000	270800000	13540000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	9341100	9341100	9341100	9341100	186822000	9341100
TOTAL EXPENSES	22881100	22881100	22881100	22881100	457622000	22881100
INCOME BEFORE TAXES	-1796006	-1796006	-1796006	-1796006	-35920120	-1796006
INVESTMENT TAX CREDIT	0	0	0	0	18682200	934110
TAX DEPRECIATION	6514080	6514080	6514080	6514080	186821996	9341100
TAXABLE INCOME	1031014	1031014	1031014	1031014	-35920116	-1796006
CURRENT INCOME TAX	494886	494886	494886	494886	-35923863	-1796193
DEFERRED INCOME TAX	-1356969	-1356969	-1356969	-1356969	3	0
TOTAL INCOME TAXES	-862083	-862083	-862083	-862083	-35923850	-1796193
NET INCOME (BOOK)	-933923	-933923	-933923	-933923	3740	187
SOURCES OF FUNDS						
NET INCOME	-933923	-933923	-933923	-933923	3740	187
FINANCIAL DEPRECIATION	9341100	9341100	9341100	9341100	186822000	9341100
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1356969	-1356969	-1356969	-1356969	3	0
NET ADDITIONS TO EQUITY	0	0	0	0	186822000	9341100
TOTAL SOURCES	7050208	7050208	7050208	7050208	373647743	18682387
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	186822000	9341100
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	186822000	9341100
NET CASH GENERATED DURING YEAR	7050208	7050208	7050208	7050208	186825743	9341287
CUMULATIVE NET CASH GENERATED	165675119	172725327	179775535	186825743	2324692587	116234629
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545237

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA5 KENAI AREA 8/8 GAS -KENAI TO TOK -NO PROCESSING

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	400000	400000	400000	400000	400000	400000	400000
COST OF SERVICE ($/MSCFD)	.312	.312	.312	.312	.312	.312	.312	.312	.312
TOTAL REVENUE	0	0	45497161	45497161	45497161	45497161	45497161	45497161	45497161
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	25403000	25403000	25403000	25403000	25403000	25403000	25403000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	24877300	24877300	24877300	24877300	24877300	24877300	24877300
TOTAL EXPENSES	0	0	50280300	50280300	50280300	50280300	50280300	50280300	50280300
INCOME BEFORE TAXES	0	0	-4783139	-4783139	-4783139	-4783139	-4783139	-4783139	-4783139
INVESTMENT TAX CREDIT	0	0	49754600	0	0	0	0	0	0
TAX DEPRECIATION	0	0	49754600	44779140	40301226	36271103	32643993	29379594	26441634
TAXABLE INCOME	0	0	-29660439	-24684979	-20207065	-16176942	-12549832	-9285433	-6347473
CURRENT INCOME TAX	0	0	-63991611	-11848790	-9699391	-7764933	-6023920	-4457008	-3046787
DEFERRED INCOME TAX	0	0	11941104	9552883	7403484	5469026	3728013	2161101	750880
TOTAL INCOME TAXES	0	0	-52050507	-2295907	-2295907	-2295907	-2295907	-2295907	-2295907
NET INCOME (BOOK)	0	0	47267368	-2487232	-2487232	-2487232	-2487232	-2487232	-2487232
SOURCES OF FUNDS									
NET INCOME	0	0	47267368	-2487232	-2487232	-2487232	-2487232	-2487232	-2487232
FINANCIAL DEPRECIATION	0	0	24877300	24877300	24877300	24877300	24877300	24877300	24877300
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	11941104	9552883	7403484	5469026	3728013	2161101	750880
NET ADDITIONS TO EQUITY	248773000	248773000	0	0	0	0	0	0	0
TOTAL SOURCES	248773000	248773000	84085772	31942951	29793552	27859094	26118081	24551169	23140948
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	248773000	248773000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	248773000	248773000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	84085772	31942951	29793552	27859094	26118081	24551169	23140948
CUMULATIVE NET CASH GENERATED	0	0	84085772	116028727	145822279	173681369	199799450	224350619	247491567
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545238

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA5 KENAI AREA 8/8 GAS -KENAI TO TOK -NO PROCESSING

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	400000	400000	400000	400000	400000	400000	400000	400000	400000
COST OF SERVICE ($/MSCFD)	.312	.312	.312	.312	.312	.312	.312	.312	.312
TOTAL REVENUE	45497161	45497161	45497161	45497161	45497161	45497161	45497161	45497161	45497161
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	25403000	25403000	25403000	25403000	25403000	25403000	25403000	25403000	25403000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	24877300	24877300	24877300	24877300	24877300	24877300	24877300	24877300	24877300
TOTAL EXPENSES	50280300	50280300	50280300	50280300	50280300	50280300	50280300	50280300	50280300
INCOME BEFORE TAXES	-4783139	-4783139	-4783139	-4783139	-4783139	-4783139	-4783139	-4783139	-4783139
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	23797471	21417724	19275951	17348356	17348356	17348356	17348356	17348356	17348356
TAXABLE INCOME	-3703310	-1323563	818210	2745805	2745805	2745805	2745805	2745805	2745805
CURRENT INCOME TAX	-1777589	-635310	392740	1317986	1317986	1317986	1317986	1317986	1317986
DEFERRED INCOME TAX	-518318	-1660597	-2688647	-3613893	-3613893	-3613893	-3613893	-3613893	-3613893
TOTAL INCOME TAXES	-2295907	-2295907	-2295907	-2295907	-2295907	-2295907	-2295907	-2295907	-2295907
NET INCOME (BOOK)	-2487232	-2487232	-2487232	-2487232	-2487232	-2487232	-2487232	-2487232	-2487232
SOURCES OF FUNDS									
NET INCOME	-2487232	-2487232	-2487232	-2487232	-2487232	-2487232	-2487232	-2487232	-2487232
FINANCIAL DEPRECIATION	24877300	24877300	24877300	24877300	24877300	24877300	24877300	24877300	24877300
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-518318	-1660597	-2688647	-3613893	-3613893	-3613893	-3613893	-3613893	-3613893
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	21871750	20729471	19701421	18776175	18776175	18776175	18776175	18776175	18776175
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	21871750	20729471	19701421	18776175	18776175	18776175	18776175	18776175	18776175
CUMULATIVE NET CASH GENERATED	269363317	290092788	309794209	328570384	347346559	366122734	384898909	403675084	422451259
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545239

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA5 KENAI AREA 8/8 GAS -KENAI TO TOK -NO PROCESSING

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	400000	400000	400000	400000	8000000	400000
COST OF SERVICE ($/MSCFD)	.312	.312	.312	.312	6.864	.343
TOTAL REVENUE	45497161	45497161	45497161	45497161	909943220	45497161
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	25403000	25403000	25403000	25403000	508060000	25403000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	24877300	24877300	24877300	24877300	497546000	24877300
TOTAL EXPENSES	50280300	50280300	50280300	50280300	1005606000	50280300
INCOME BEFORE TAXES	-4783139	-4783139	-4783139	-4783139	-95662780	-4783139
INVESTMENT TAX CREDIT	0	0	0	0	49754600	2487730
TAX DEPRECIATION	17348356	17348356	17348356	17348356	497545996	24877300
TAXABLE INCOME	2745805	2745805	2745805	2745805	-95662776	-4783139
CURRENT INCOME TAX	1317986	1317986	1317986	1317986	-95672739	-4783637
DEFERRED INCOME TAX	-3613893	-3613893	-3613893	-3613893	-1	0
TOTAL INCOME TAXES	-2295907	-2295907	-2295907	-2295907	-95672740	-4783637
NET INCOME (BOOK)	-2487232	-2487232	-2487232	-2487232	9960	498
SOURCES OF FUNDS						
NET INCOME	-2487232	-2487232	-2487232	-2487232	9960	498
FINANCIAL DEPRECIATION	24877300	24877300	24877300	24877300	497546000	24877300
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-3613893	-3613893	-3613893	-3613893	-1	0
NET ADDITIONS TO EQUITY	0	0	0	0	497546000	24877300
TOTAL SOURCES	18776175	18776175	18776175	18776175	995101959	49755098
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	497546000	24877300
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	497546000	24877300
NET CASH GENERATED DURING YEAR	18776175	18776175	18776175	18776175	497555959	24877798
CUMULATIVE NET CASH GENERATED	441227434	460003609	478779784	497555959	6191141804	6095570902
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545240

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA6 KENAI AREA 8/8 GAS -KENAI TO FAIRBANKS -NO PROCESSING

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	400000	400000	400000	400000	400000	400000	400000
COST OF SERVICE ($/MSCFD)	.310	.310	.310	.310	.310	.310	.310	.310	.310
TOTAL REVENUE	0	0	45276774	45276774	45276774	45276774	45276774	45276774	45276774
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	25315000	25315000	25315000	25315000	25315000	25315000	25315000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	24713400	24713400	24713400	24713400	24713400	24713400	24713400
TOTAL EXPENSES	0	0	50028400	50028400	50028400	50028400	50028400	50028400	50028400
INCOME BEFORE TAXES	0	0	-4751626	-4751626	-4751626	-4751626	-4751626	-4751626	-4751626
INVESTMENT TAX CREDIT	0	0	49426800	0	0	0	0	0	0
TAX DEPRECIATION	0	0	49426800	44484120	40035708	36032137	32428923	29186031	26267428
TAXABLE INCOME	0	0	-29465026	-24522346	-20073934	-16070363	-12467149	-9224257	-6305654
CURRENT INCOME TAX	0	0	-63570013	-11770726	-9635489	-7713775	-5984232	-4427644	-3026714
DEFERRED INCOME TAX	0	0	11862432	9489945	7354708	5432994	3703451	2146863	745933
TOTAL INCOME TAXES	0	0	-51707581	-2280781	-2280781	-2280781	-2280781	-2280781	-2280781
NET INCOME (BOOK)	0	0	46955955	-2470845	-2470845	-2470845	-2470845	-2470845	-2470845
SOURCES OF FUNDS									
NET INCOME	0	0	46955955	-2470845	-2470845	-2470845	-2470845	-2470845	-2470845
FINANCIAL DEPRECIATION	0	0	24713400	24713400	24713400	24713400	24713400	24713400	24713400
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	11862432	9489945	7354708	5432994	3703451	2146863	745933
NET ADDITIONS TO EQUITY	247134000	247134000	0	0	0	0	0	0	0
TOTAL SOURCES	247134000	247134000	83531787	31732500	29597263	27675549	25946006	24389418	22988488
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	247134000	247134000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	247134000	247134000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	83531787	31732500	29597263	27675549	25946006	24389418	22988488
CUMULATIVE NET CASH GENERATED	0	0	83531787	115264287	144861550	172537099	198483105	222872523	245861011
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545241

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA6 KENAI AREA B/B GAS -KENAI TO FAIRBANKS -NO PROCESSING

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	400000	400000	400000	400000	400000	400000	400000	400000	400000
COST OF SERVICE ($/MSCFD)	.310	.310	.310	.310	.310	.310	.310	.310	.310
TOTAL REVENUE	45276774	45276774	45276774	45276774	45276774	45276774	45276774	45276774	45276774
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	25315000	25315000	25315000	25315000	25315000	25315000	25315000	25315000	25315000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	24713400	24713400	24713400	24713400	24713400	24713400	24713400	24713400	24713400
TOTAL EXPENSES	50028400	50028400	50028400	50028400	50028400	50028400	50028400	50028400	50028400
INCOME BEFORE TAXES	-4751626	-4751626	-4751626	-4751626	-4751626	-4751626	-4751626	-4751626	-4751626
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	23640685	21276617	19148955	17234060	17234060	17234060	17234060	17234060	17234060
TAXABLE INCOME	-3678911	-1314843	812819	2727714	2727714	2727714	2727714	2727714	2727714
CURRENT INCOME TAX	-1765878	-631125	390153	1309303	1309303	1309303	1309303	1309303	1309303
DEFERRED INCOME TAX	-514903	-1649656	-2670934	-3590084	-3590084	-3590084	-3590084	-3590084	-3590084
TOTAL INCOME TAXES	-2280781	-2280781	-2280781	-2280781	-2280781	-2280781	-2280781	-2280781	-2280781
NET INCOME (BOOK)	-2470845	-2470845	-2470845	-2470845	-2470845	-2470845	-2470845	-2470845	-2470845
SOURCES OF FUNDS									
NET INCOME	-2470845	-2470845	-2470845	-2470845	-2470845	-2470845	-2470845	-2470845	-2470845
FINANCIAL DEPRECIATION	24713400	24713400	24713400	24713400	24713400	24713400	24713400	24713400	24713400
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-514903	-1649656	-2670934	-3590084	-3590084	-3590084	-3590084	-3590084	-3590084
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	21727652	20592899	19571621	18652471	18652471	18652471	18652471	18652471	18652471
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	21727652	20592899	19571621	18652471	18652471	18652471	18652471	18652471	18652471
CUMULATIVE NET CASH GENERATED	267588663	288181562	307753183	326405654	345058125	363710596	382363067	401015538	419668009
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545242

CASE VIII

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIA6 KENAI AREA 8/8 GAS -KENAI TO FAIRBANKS -NO PROCESSING

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	400000	400000	400000	400000	8000000	400000
COST OF SERVICE ($/MSCFD)	.310	.310	.310	.310	6.820	.341
TOTAL REVENUE	45276774	45276774	45276774	45276774	905535480	45276774
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	25315000	25315000	25315000	25315000	506300000	25315000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	24713400	24713400	24713400	24713400	494268000	24713400
TOTAL EXPENSES	50028400	50028400	50028400	50028400	1000568000	50028400
INCOME BEFORE TAXES	-4751626	-4751626	-4751626	-4751626	-95032520	-4751626
INVESTMENT TAX CREDIT	0	0	0	0	49426800	2471340
TAX DEPRECIATION	17234060	17234060	17234060	17234060	494268004	24713400
TAXABLE INCOME	2727714	2727714	2727714	2727714	-95032524	-4751626
CURRENT INCOME TAX	1309303	1309303	1309303	1309303	-95042413	-4752121
DEFERRED INCOME TAX	-3590084	-3590084	-3590084	-3590084	-7	0
TOTAL INCOME TAXES	-2280781	-2280781	-2280781	-2280781	-95042420	-4752121
NET INCOME (BOOK)	-2470845	-2470845	-2470845	-2470845	9900	495
SOURCES OF FUNDS						
NET INCOME	-2470845	-2470845	-2470845	-2470845	9900	495
FINANCIAL DEPRECIATION	24713400	24713400	24713400	24713400	494268000	24713400
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-3590084	-3590084	-3590084	-3590084	-7	0
NET ADDITIONS TO EQUITY	0	0	0	0	494268000	24713400
TOTAL SOURCES	18652471	18652471	18652471	18652471	988545093	49427295
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	494268000	24713400
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	494268000	24713400
NET CASH GENERATED DURING YEAR	18652471	18652471	18652471	18652471	494277093	24713895
CUMULATIVE NET CASH GENERATED	438320480	456972951	475625422	494277893	3615035205	3707517625
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545243

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIIA PRUDHOE 1/8 GAS -PRUDHOE TO FAIRBANKS -TWO PHASE FLOW

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.407	.407	.407	.407	.407	.407	.407	.407	.407
TOTAL REVENUE	0	0	37100437	37100437	37100437	37100437	37100437	37100437	37100437
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	20580000	20580000	20580000	20580000	20580000	20580000	20580000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	20452900	20452900	20452900	20452900	20452900	20452900	20452900
TOTAL EXPENSES	0	0	41032900	41032900	41032900	41032900	41032900	41032900	41032900
INCOME BEFORE TAXES	0	0	-3932463	-3932463	-3932463	-3932463	-3932463	-3932463	-3932463
INVESTMENT TAX CREDIT	0	0	40905800	0	0	0	0	0	0
TAX DEPRECIATION	0	0	40905800	36815220	33133698	29820328	26838295	24154466	21739019
TAXABLE INCOME	0	0	-24385363	-20294783	-16613261	-13299891	-10317858	-7634029	-5218582
CURRENT INCOME TAX	0	0	-52610774	-9741496	-7974365	-6383948	-4952572	-3664334	-2504920
DEFERRED INCOME TAX	0	0	9817392	7853914	6086783	4496366	3064990	1776752	617338
TOTAL INCOME TAXES	0	0	-42793382	-1887582	-1887582	-1887582	-1887582	-1887582	-1887582
NET INCOME (BOOK)	0	0	38860919	-2044881	-2044881	-2044881	-2044881	-2044881	-2044881
SOURCES OF FUNDS									
NET INCOME	0	0	38860919	-2044881	-2044881	-2044881	-2044881	-2044881	-2044881
FINANCIAL DEPRECIATION	0	0	20452900	20452900	20452900	20452900	20452900	20452900	20452900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	9817392	7853914	6086783	4496366	3064990	1776752	617338
NET ADDITIONS TO EQUITY	204529000	204529000	0	0	0	0	0	0	0
TOTAL SOURCES	204529000	204529000	69131211	26261933	24494802	22904385	21473009	20184771	19025357
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	204529000	204529000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	204529000	204529000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	69131211	26261933	24494802	22904385	21473009	20184771	19025357
CUMULATIVE NET CASH GENERATED	0	0	69131211	95393144	119887946	142792331	164265340	184450111	203475468
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545245

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIIA PRUDHOE 1/8 GAS -PRUDHOE TO FAIRBANKS -TWO PHASE FLOW

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.407	.407	.407	.407	.407	.407	.407	.407	.407
TOTAL REVENUE	37100437	37100437	37100437	37100437	37100437	37100437	37100437	37100437	37100437
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	20580000	20580000	20580000	20580000	20580000	20580000	20580000	20580000	20580000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	20452900	20452900	20452900	20452900	20452900	20452900	20452900	20452900	20452900
TOTAL EXPENSES	41032900	41032900	41032900	41032900	41032900	41032900	41032900	41032900	41032900
INCOME BEFORE TAXES	-3932463	-3932463	-3932463	-3932463	-3932463	-3932463	-3932463	-3932463	-3932463
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	19565117	17608606	15847745	14262971	14262971	14262971	14262971	14262971	14262971
TAXABLE INCOME	-3044680	-1089169	672692	2257466	2257466	2257466	2257466	2257466	2257466
CURRENT INCOME TAX	-1461447	-522321	322892	1083584	1083584	1083584	1083584	1083584	1083584
DEFERRED INCOME TAX	-426135	-1365261	-2210474	-2971166	-2971166	-2971166	-2971166	-2971166	-2971166
TOTAL INCOME TAXES	-1887582	-1887582	-1887582	-1887582	-1887582	-1887582	-1887582	-1887582	-1887582
NET INCOME (BOOK)	-2044881	-2044881	-2044881	-2044881	-2044881	-2044881	-2044881	-2044881	-2044881
SOURCES OF FUNDS									
NET INCOME	-2044881	-2044881	-2044881	-2044881	-2044881	-2044881	-2044881	-2044881	-2044881
FINANCIAL DEPRECIATION	20452900	20452900	20452900	20452900	20452900	20452900	20452900	20452900	20452900
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-426135	-1365261	-2210474	-2971166	-2971166	-2971166	-2971166	-2971166	-2971166
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	17981884	17042758	16197545	15436853	15436853	15436853	15436853	15436853	15436853
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	17981884	17042758	16197545	15436853	15436853	15436853	15436853	15436853	15436853
CUMULATIVE NET CASH GENERATED	221457352	238500110	254697655	270134508	285571361	301008214	316445067	331881920	347318773
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545246

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIIA PRUDHOE 1/8 GAS -PRUDHOE TO FAIRBANKS -TWO PHASE FLOW

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	5000000	250000
COST OF SERVICE ($/MSCFD)	.407	.407	.407	.407	8.954	.448
TOTAL REVENUE	37100437	37100437	37100437	37100437	742008740	37100437
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	20580000	20580000	20580000	20580000	411600000	20580000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	20452900	20452900	20452900	20452900	409058000	20452900
TOTAL EXPENSES	41032900	41032900	41032900	41032900	820658000	41032900
INCOME BEFORE TAXES	-3932463	-3932463	-3932463	-3932463	-78649260	-3932463
INVESTMENT TAX CREDIT	0	0	0	0	40905800	2045290
TAX DEPRECIATION	14262971	14262971	14262971	14262971	409058004	20452900
TAXABLE INCOME	2257466	2257466	2257466	2257466	-78649264	-3932463
CURRENT INCOME TAX	1083584	1083584	1083584	1083584	-78657445	-3932872
DEFERRED INCOME TAX	-2971166	-2971166	-2971166	-2971166	5	0
TOTAL INCOME TAXES	-1887582	-1887582	-1887582	-1887582	-78657440	-3932872
NET INCOME (BOOK)	-2044881	-2044881	-2044881	-2044881	8180	409
SOURCES OF FUNDS						
NET INCOME	-2044881	-2044881	-2044881	-2044881	8180	409
FINANCIAL DEPRECIATION	20452900	20452900	20452900	20452900	409058000	20452900
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-2971166	-2971166	-2971166	-2971166	5	0
NET ADDITIONS TO EQUITY	0	0	0	0	409058000	20452900
TOTAL SOURCES	15436853	15436853	15436853	15436853	818124185	40906209
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	409058000	20452900
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	409058000	20452900
NET CASH GENERATED DURING YEAR	15436853	15436853	15436853	15436853	409066185	20453309
CUMULATIVE NET CASH GENERATED	362755626	378192479	393629332	409066185	5090054133	254502707
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545247

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIIB PRUDHOE 1/8 GAS -PRUDHOE TO KENAI -TWO PHASE FLOW

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (MSCFD)	0	0	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.841	.841	.841	.841	.841	.841	.841	.841	.841
TOTAL REVENUE	0	0	76737566	76737566	76737566	76737566	76737566	76737566	76737566
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	41100000	41100000	41100000	41100000	41100000	41100000	41100000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	44120600	44120600	44120600	44120600	44120600	44120600	44120600
TOTAL EXPENSES	0	0	85220600	85220600	85220600	85220600	85220600	85220600	85220600
INCOME BEFORE TAXES	0	0	-8483034	-8483034	-8483034	-8483034	-8483034	-8483034	-8483034
INVESTMENT TAX CREDIT	0	0	88241200	0	0	0	0	0	0
TAX DEPRECIATION	0	0	88241200	79417080	71475372	64327835	57895051	52105546	46894992
TAXABLE INCOME	0	0	-52603634	-43779514	-35837806	-28690269	-22257485	-16467980	-11257426
CURRENT INCOME TAX	0	0	-113490944	-21014167	-17202147	-13771329	-10683593	-7904630	-5403564
DEFERRED INCOME TAX	0	0	21177888	16942311	13130291	9699473	6611737	3832774	1331708
TOTAL INCOME TAXES	0	0	-92313056	-4071856	-4071856	-4071856	-4071856	-4071856	-4071856
NET INCOME (BOOK)	0	0	83830022	-4411178	-4411178	-4411178	-4411178	-4411178	-4411178
SOURCES OF FUNDS									
NET INCOME	0	0	83830022	-4411178	-4411178	-4411178	-4411178	-4411178	-4411178
FINANCIAL DEPRECIATION	0	0	44120600	44120600	44120600	44120600	44120600	44120600	44120600
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	21177888	16942311	13130291	9699473	6611737	3832774	1331708
NET ADDITIONS TO EQUITY	441206000	441206000	0	0	0	0	0	0	0
TOTAL SOURCES	441206000	441206000	149128510	56651733	52839713	49408895	46321159	43542196	41041130
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	441206000	441206000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	441206000	441206000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	149128510	56651733	52839713	49408895	46321159	43542196	41041130
CUMULATIVE NET CASH GENERATED	0	0	149128510	205780243	258619956	308028851	354350010	397892206	438933336
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545248

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIIB PRUDHOE 1/8 GAS -PRUDHOE TO KENAI -TWO PHASE FLOW

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	250000	250000	250000	250000	250000
COST OF SERVICE ($/MSCFD)	.841	.841	.841	.841	.841	.841	.841	.841	.841
TOTAL REVENUE	76737566	76737566	76737566	76737566	76737566	76737566	76737566	76737566	76737566
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	41100000	41100000	41100000	41100000	41100000	41100000	41100000	41100000	41100000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	44120600	44120600	44120600	44120600	44120600	44120600	44120600	44120600	44120600
TOTAL EXPENSES	85220600	85220600	85220600	85220600	85220600	85220600	85220600	85220600	85220600
INCOME BEFORE TAXES	-8483034	-8483034	-8483034	-8483034	-8483034	-8483034	-8483034	-8483034	-8483034
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	42205492	37984943	34186449	30767804	30767804	30767804	30767804	30767804	30767804
TAXABLE INCOME	-6567926	-2347377	1451117	4869762	4869762	4869762	4869762	4869762	4869762
CURRENT INCOME TAX	-3152605	-1126741	696536	2337486	2337486	2337486	2337486	2337486	2337486
DEFERRED INCOME TAX	-919251	-2945115	-4768392	-6409342	-6409342	-6409342	-6409342	-6409342	-6409342
TOTAL INCOME TAXES	-4071856	-4071856	-4071856	-4071856	-4071856	-4071856	-4071856	-4071856	-4071856
NET INCOME (BOOK)	-4411178	-4411178	-4411178	-4411178	-4411178	-4411178	-4411178	-4411178	-4411178
SOURCES OF FUNDS									
NET INCOME	-4411178	-4411178	-4411178	-4411178	-4411178	-4411178	-4411178	-4411178	-4411178
FINANCIAL DEPRECIATION	44120600	44120600	44120600	44120600	44120600	44120600	44120600	44120600	44120600
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-919251	-2945115	-4768392	-6409342	-6409342	-6409342	-6409342	-6409342	-6409342
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	38790171	36764307	34941030	33300080	33300080	33300080	33300080	33300080	33300080
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	38790171	36764307	34941030	33300080	33300080	33300080	33300080	33300080	33300080
CUMULATIVE NET CASH GENERATED	477723507	514487814	549428844	582728924	616029004	649329084	682629164	715929244	749229324
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545249

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE VIIIB PRUDHOE 1/8 GAS -PRUDHOE TO KENAI -TWO PHASE FLOW

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (MSCFD)	250000	250000	250000	250000	5000000	250000
COST OF SERVICE ($/MSCFD)	.841	.841	.841	.841	18.502	.925
TOTAL REVENUE	76737566	76737566	76737566	76737566	1534751320	76737566
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	41100000	41100000	41100000	41100000	822000000	41100000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	44120600	44120600	44120600	44120600	882412000	44120600
TOTAL EXPENSES	85220600	85220600	85220600	85220600	1704412000	85220600
INCOME BEFORE TAXES	-8483034	-8483034	-8483034	-8483034	-169660680	-8483034
INVESTMENT TAX CREDIT	0	0	0	0	88241200	4412060
TAX DEPRECIATION	30767804	30767804	30767804	30767804	882412000	44120600
TAXABLE INCOME	4869762	4869762	4869762	4869762	-169660680	-8483034
CURRENT INCOME TAX	2337486	2337486	2337486	2337486	-169678320	-8483916
DEFERRED INCOME TAX	-6409342	-6409342	-6409342	-6409342	4	0
TOTAL INCOME TAXES	-4071856	-4071856	-4071856	-4071856	-169678320	-8483916
NET INCOME (BOOK)	-4411178	-4411178	-4411178	-4411178	17640	882
SOURCES OF FUNDS						
NET INCOME	-4411178	-4411178	-4411178	-4411178	17640	882
FINANCIAL DEPRECIATION	44120600	44120600	44120600	44120600	882412000	44120600
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-6409342	-6409342	-6409342	-6409342	4	0
NET ADDITIONS TO EQUITY	0	0	0	0	882412000	44120600
TOTAL SOURCES	33300080	33300080	33300080	33300080	1764841744	88242082
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	882412000	44120600
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	882412000	44120600
NET CASH GENERATED DURING YEAR	33300080	33300080	33300080	33300080	882429744	44121482
CUMULATIVE NET CASH GENERATED	782529404	815829484	849129564	8824.9644**********		949008306
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545250

Pipe Line Technologists, Inc.
a Kaneb company

CASE IX

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IX PROCESS 8/8 GAS AT HAINES JCT. -EXTRACT C2+ -LIQ PL TO HAINES

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	155300	155300	155300	155300	155300	155300	155300
COST OF SERVICE ($/BBL)	.177	.177	.177	.177	.177	.177	.177	.177	.177
TOTAL REVENUE	0	0	10045473	10045473	10045473	10045473	10045473	10045473	10045473
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	5612000	5612000	5612000	5612000	5612000	5612000	5612000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	5488800	5488800	5488800	5488800	5488800	5488800	5488800
TOTAL EXPENSES	0	0	11100800	11100800	11100800	11100800	11100800	11100800	11100800
INCOME BEFORE TAXES	0	0	-1055327	-1055327	-1055327	-1055327	-1055327	-1055327	-1055327
INVESTMENT TAX CREDIT	0	0	10977600	0	0	0	0	0	0
TAX DEPRECIATION	0	0	10977600	9879840	8891856	8002670	7202403	6482163	5833947
TAXABLE INCOME	0	0	-6544127	-5446367	-4458383	-3569197	-2768930	-2048690	-1400474
CURRENT INCOME TAX	0	0	-14118781	-2614256	-2140024	-1713215	-1329087	-983371	-672228
DEFERRED INCOME TAX	0	0	2634624	2107699	1633467	1206658	822530	476814	165671
TOTAL INCOME TAXES	0	0	-11484157	-506557	-506557	-506557	-506557	-506557	-506557
NET INCOME (BOOK)	0	0	10428830	-548770	-548770	-548770	-548770	-548770	-548770
SOURCES OF FUNDS									
NET INCOME	0	0	10428830	-548770	-548770	-548770	-548770	-548770	-548770
FINANCIAL DEPRECIATION	0	0	5488800	5488800	5488800	5488800	5488800	5488800	5488800
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	2634624	2107699	1633467	1206658	822530	476814	165671
NET ADDITIONS TO EQUITY	54888000	54888000	0	0	0	0	0	0	0
TOTAL SOURCES	54888000	54888000	18552254	7047729	6573497	6146688	5762560	5416844	5105701
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	54888000	54888000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	54888000	54888000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	18552254	7047729	6573497	6146688	5762560	5416844	5105701
CUMULATIVE NET CASH GENERATED	0	0	18552254	25599983	32173480	38320168	44082728	49499572	54605273
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545252

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IX PROCESS B/R GAS AT HAINES JCT. -EXTRACT C2+ -LIQ PL TO HAINES

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	155300	155300	155300	155300	155300	155300	155300	155300	155300
COST OF SERVICE ($/BBL)	.177	.177	.177	.177	.177	.177	.177	.177	.177
TOTAL REVENUE	10045473	10045473	10045473	10045473	10045473	10045473	10045473	10045473	10045473
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	5612000	5612000	5612000	5612000	5612000	5612000	5612000	5612000	5612000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	5488800	5488800	5488800	5488800	5488800	5488800	5488800	5488800	5488800
TOTAL EXPENSES	11100800	11100800	11100800	11100800	11100800	11100800	11100800	11100800	11100800
INCOME BEFORE TAXES	-1055327	-1055327	-1055327	-1055327	-1055327	-1055327	-1055327	-1055327	-1055327
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	5250552	4725497	4252947	3827652	3827652	3827652	3827652	3827652	3827652
TAXABLE INCOME	-817079	-292024	180526	605821	605821	605821	605821	605821	605821
CURRENT INCOME TAX	-392198	-140172	86652	290794	290794	290794	290794	290794	290794
DEFERRED INCOME TAX	-114359	-366385	-593209	-797351	-797351	-797351	-797351	-797351	-797351
TOTAL INCOME TAXES	-506557	-506557	-506557	-506557	-506557	-506557	-506557	-506557	-506557
NET INCOME (BOOK)	-548770	-548770	-548770	-548770	-548770	-548770	-548770	-548770	-548770
SOURCES OF FUNDS									
NET INCOME	-548770	-548770	-548770	-548770	-548770	-548770	-548770	-548770	-548770
FINANCIAL DEPRECIATION	5488800	5488800	5488800	5488800	5488800	5488800	5488800	5488800	5488800
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-114359	-366385	-593209	-797351	-797351	-797351	-797351	-797351	-797351
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	4825671	4573645	4346821	4142679	4142679	4142679	4142679	4142679	4142679
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	4825671	4573645	4346821	4142679	4142679	4142679	4142679	4142679	4142679
CUMULATIVE NET CASH GENERATED	59430944	64004589	68351410	72494089	76636768	80779447	84922126	89064805	93207484
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545253

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE IX PROCESS 8/8 GAS AT HAINES JCT. -EXTRACT C2+ -LIQ PL TO HAINES

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	155300	155300	155300	155300	3106000	155300
COST OF SERVICE ($/BBL)	.177	.177	.177	.177	3.894	.195
TOTAL REVENUE	10045473	10045473	10045473	10045473	200909460	10045473
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	5612000	5612000	5612000	5612000	112240000	5612000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	5488800	5488800	5488800	5488800	109776000	5488800
TOTAL EXPENSES	11100800	11100800	11100800	11100800	222016000	11100800
INCOME BEFORE TAXES	-1055327	-1055327	-1055327	-1055327	-21106540	-1055327
INVESTMENT TAX CREDIT	0	0	0	0	109776000	548880
TAX DEPRECIATION	3827652	3827652	3827652	3827652	109775995	5488800
TAXABLE INCOME	605821	605821	605821	605821	-21106535	-1055327
CURRENT INCOME TAX	290794	290794	290794	290794	-21108740	-1055437
DEFERRED INCOME TAX	-797351	-797351	-797351	-797351	0	0
TOTAL INCOME TAXES	-506557	-506557	-506557	-506557	-21108740	-1055437
NET INCOME (BOOK)	-548770	-548770	-548770	-548770	2200	110
SOURCES OF FUNDS						
NET INCOME	-548770	-548770	-548770	-548770	2200	110
FINANCIAL DEPRECIATION	5488800	5488800	5488800	5488800	109776000	5488800
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-797351	-797351	-797351	-797351	0	0
NET ADDITIONS TO EQUITY	0	0	0	0	109776000	5488800
TOTAL SOURCES	4142679	4142679	4142679	4142679	219554200	10977710
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	109776000	5488800
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	109776000	5488800
NET CASH GENERATED DURING YEAR	4142679	4142679	4142679	4142679	109778200	5488910
CUMULATIVE NET CASH GENERATED	97350163	101492842	105635521	109778200	1365981846	68299092
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545254

Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE X-PL ETHYLENE PIPELINE -FAIRBANKS TO KENAI

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY TRANSPORTATION VOLUME (BBLS)	0	0	19000	19000	19000	19000	19000	19000	19000
COST OF SERVICE ($/BBL)	4.015	4.015	4.015	4.015	4.015	4.015	4.015	4.015	4.015
TOTAL REVENUE	0	0	27845345	27845345	27845345	27845345	27845345	27845345	27845345
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	20600000	20600000	20600000	20600000	20600000	20600000	20600000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	8970000	8970000	8970000	8970000	8970000	8970000	8970000
TOTAL EXPENSES	0	0	29570000	29570000	29570000	29570000	29570000	29570000	29570000
INCOME BEFORE TAXES	0	0	-1724655	-1724655	-1724655	-1724655	-1724655	-1724655	-1724655
INVESTMENT TAX CREDIT	0	0	17940000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	17940000	16146000	14531400	13078260	11770434	10593391	9534052
TAXABLE INCOME	0	0	-10694655	-8900655	-7286055	-5832915	-4525089	-3348046	-2288707
CURRENT INCOME TAX	0	0	-23073434	-4272314	-3497306	-2799799	-2172043	-1607062	-1098579
DEFERRED INCOME TAX	0	0	4305600	3444480	2669472	1971965	1344209	779228	270745
TOTAL INCOME TAXES	0	0	-18767834	-827834	-827834	-827834	-827834	-827834	-827834
NET INCOME (BOOK)	0	0	17043179	-896821	-896821	-896821	-896821	-896821	-896821
SOURCES OF FUNDS									
NET INCOME	0	0	17043179	-896821	-896821	-896821	-896821	-896821	-896821
FINANCIAL DEPRECIATION	0	0	8970000	8970000	8970000	8970000	8970000	8970000	8970000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	4305600	3444480	2669472	1971965	1344209	779228	270745
NET ADDITIONS TO EQUITY	89700000	89700000	0	0	0	0	0	0	0
TOTAL SOURCES	89700000	89700000	30318779	11517659	10742651	10045144	9417388	8852407	8343924
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	89700000	89700000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	89700000	89700000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	30318779	11517659	10742651	10045144	9417388	8852407	8343924
CUMULATIVE NET CASH GENERATED	0	0	30318779	41836438	52579089	62624233	72041621	80894028	89237952
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545255

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE X-PL ETHYLENE PIPELINE -FAIRBANKS TO KENAI

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY TRANSPORTATION VOLUME (BBLS)	19000	19000	19000	19000	19000	19000	19000	19000	19000
COST OF SERVICE ($/BBL)	4.015	4.015	4.015	4.015	4.015	4.015	4.015	4.015	4.015
TOTAL REVENUE	27845345	27845345	27845345	27845345	27845345	27845345	27845345	27845345	27845345
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	20600000	20600000	20600000	20600000	20600000	20600000	20600000	20600000	20600000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	8970000	8970000	8970000	8970000	8970000	8970000	8970000	8970000	8970000
TOTAL EXPENSES	29570000	29570000	29570000	29570000	29570000	29570000	29570000	29570000	29570000
INCOME BEFORE TAXES	-1724655	-1724655	-1724655	-1724655	-1724655	-1724655	-1724655	-1724655	-1724655
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	8580646	7722582	6950324	6255291	6255291	6255291	6255291	6255291	6255291
TAXABLE INCOME	-1335301	-477237	295021	990054	990054	990054	990054	990054	990054
CURRENT INCOME TAX	-640945	-229074	141610	475226	475226	475226	475226	475226	475226
DEFERRED INCOME TAX	-186889	-598760	-969444	-1303060	-1303060	-1303060	-1303060	-1303060	-1303060
TOTAL INCOME TAXES	-827834	-827834	-827834	-827834	-827834	-827834	-827834	-827834	-827834
NET INCOME (BOOK)	-896821	-896821	-896821	-896821	-896821	-896821	-896821	-896821	-896821
SOURCES OF FUNDS									
NET INCOME	-896821	-896821	-896821	-896821	-896821	-896821	-896821	-896821	-896821
FINANCIAL DEPRECIATION	8970000	8970000	8970000	8970000	8970000	8970000	8970000	8970000	8970000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-186889	-598760	-969444	-1303060	-1303060	-1303060	-1303060	-1303060	-1303060
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	7886290	7474419	7103735	6770119	6770119	6770119	6770119	6770119	6770119
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	7886290	7474419	7103735	6770119	6770119	6770119	6770119	6770119	6770119
CUMULATIVE NET CASH GENERATED	97124242	104598661	111702396	118472515	125242634	132012753	138782872	145552991	152323110
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

AGO 545256

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE X-PL ETHYLENE PIPELINE -FAIRBANKS TO KENAI

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY TRANSPORTATION VOLUME (BBLS)	19000	19000	19000	19000	380000	19000
COST OF SERVICE ($/BBL)	4.015	4.015	4.015	4.015	88.230	4.417
TOTAL REVENUE	27845345	27845345	27845345	27845345	556906900	27845345
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	20600000	20600000	20600000	20600000	412000000	20600000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	8970000	8970000	8970000	8970000	179400000	8970000
TOTAL EXPENSES	29570000	29570000	29570000	29570000	591400000	29570000
INCOME BEFORE TAXES	-1724655	-1724655	-1724655	-1724655	-34493100	-1724655
INVESTMENT TAX CREDIT	0	0	0	0	17940000	897000
TAX DEPRECIATION	6255291	6255291	6255291	6255291	172399999	8970000
TAXABLE INCOME	990054	990054	990054	990054	-34493099	-1724655
CURRENT INCOME TAX	475226	475226	475226	475226	-34496686	-1724834
DEFERRED INCOME TAX	-1303060	-1303060	-1303060	-1303060	6	0
TOTAL INCOME TAXES	-827834	-827834	-827834	-827834	-34496680	-1724834
NET INCOME (BOOK)	-896821	-896821	-896821	-896821	3580	179
SOURCES OF FUNDS						
NET INCOME	-896821	-896821	-896821	-896821	3580	179
FINANCIAL DEPRECIATION	8970000	8970000	8970000	8970000	179400000	8970000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-1303060	-1303060	-1303060	-1303060	6	0
NET ADDITIONS TO EQUITY	0	0	0	0	179400000	8970000
TOTAL SOURCES	6770119	6770119	6770119	6770119	358803586	17940179
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	179400000	8970000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	179400000	8970000
NET CASH GENERATED DURING YEAR	6770119	6770119	6770119	6770119	179403586	8970179
CUMULATIVE NET CASH GENERATED	150893229	165863348	172633467	179403586	2232337944	111616897
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

AGO 545257

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE X-GP ETHYLENE PLANT AT FAIRBANKS

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY VOLUME (BBLS)	0	0	19000	19000	19000	19000	19000	19000	19000
COST OF SERVICE ($/BBL)	4.282	4.282	4.282	4.282	4.282	4.282	4.282	4.282	4.282
TOTAL REVENUE	0	0	29693269	29693269	29693269	29693269	29693269	29693269	29693269
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	9500000	9500000	9500000	9500000	9500000	9500000	9500000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	25000000	25000000	25000000	25000000	25000000	25000000	25000000
TOTAL EXPENSES	0	0	34500000	34500000	34500000	34500000	34500000	34500000	34500000
INCOME BEFORE TAXES	0	0	-4806731	-4806731	-4806731	-4806731	-4806731	-4806731	-4806731
INVESTMENT TAX CREDIT	0	0	50000000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	50000000	45000000	40500000	36450000	32805000	29524500	26572050
TAXABLE INCOME	0	0	-29806731	-24806731	-20306731	-16256731	-12611731	-9331231	-6378781
CURRENT INCOME TAX	0	0	-64307231	-11907231	-9747231	-7803231	-6053631	-4478991	-3061815
DEFERRED INCOME TAX	0	0	12000000	9600000	7440000	5496000	3746400	2171760	754584
TOTAL INCOME TAXES	0	0	-52307231	-2307231	-2307231	-2307231	-2307231	-2307231	-2307231
NET INCOME (BOOK)	0	0	47500500	-2499500	-2499500	-2499500	-2499500	-2499500	-2499500
SOURCES OF FUNDS									
NET INCOME	0	0	47500500	-2499500	-2499500	-2499500	-2499500	-2499500	-2499500
FINANCIAL DEPRECIATION	0	0	25000000	25000000	25000000	25000000	25000000	25000000	25000000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	12000000	9600000	7440000	5496000	3746400	2171760	754584
NET ADDITIONS TO EQUITY	250000000	250000000	0	0	0	0	0	0	0
TOTAL SOURCES	250000000	250000000	84500500	32100500	29940500	27996500	26246900	24672260	23255084
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	250000000	250000000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	250000000	250000000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	84500500	32100500	29940500	27996500	26246900	24672260	23255084
CUMULATIVE NET CASH GENERATED	0	0	84500500	116601000	146541500	174538000	200784900	225457160	248712244
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

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EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE X-GP ETHYLENE PLANT AT FAIRBANKS

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY VOLUME (BBLS)	19000	19000	19000	19000	19000	19000	19000	19000	19000
COST OF SERVICE ($/BBL)	4.282	4.282	4.282	4.282	4.282	4.282	4.282	4.282	4.282
TOTAL REVENUE	29693269	29693269	29693269	29693269	29693269	29693269	29693269	29693269	29693269
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	9500000	9500000	9500000	9500000	9500000	9500000	9500000	9500000	9500000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	25000000	25000000	25000000	25000000	25000000	25000000	25000000	25000000	25000000
TOTAL EXPENSES	34500000	34500000	34500000	34500000	34500000	34500000	34500000	34500000	34500000
INCOME BEFORE TAXES	-4806731	-4806731	-4806731	-4806731	-4806731	-4806731	-4806731	-4806731	-4806731
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	23914845	21523361	19371024	17433922	17433922	17433922	17433922	17433922	17433922
TAXABLE INCOME	-3721576	-1330092	822245	2759347	2759347	2759347	2759347	2759347	2759347
CURRENT INCOME TAX	-1786356	-638444	394677	1324487	1324487	1324487	1324487	1324487	1324487
DEFERRED INCOME TAX	-520875	-1668787	-2701908	-3631718	-3631718	-3631718	-3631718	-3631718	-3631718
TOTAL INCOME TAXES	-2307231	-2307231	-2307231	-2307231	-2307231	-2307231	-2307231	-2307231	-2307231
NET INCOME (PROOF)	-2499500	-2499500	-2499500	-2499500	-2499500	-2499500	-2499500	-2499500	-2499500
SOURCES OF FUNDS									
NET INCOME	-2499500	-2499500	-2499500	-2499500	-2499500	-2499500	-2499500	-2499500	-2499500
FINANCIAL DEPRECIATION	25000000	25000000	25000000	25000000	25000000	25000000	25000000	25000000	25000000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-520875	-1668787	-2701908	-3631718	-3631718	-3631718	-3631718	-3631718	-3631718
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	21979625	20831713	19798592	18868782	18868782	18868782	18868782	18868782	18868782
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	21979625	20831713	19798592	18868782	18868782	18868782	18868782	18868782	18868782
CUMULATIVE NET CASH GENERATED	270691869	291523582	311322174	330190956	349059738	367928520	386797302	405666084	424534866
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

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Pipe Line Technologists, Inc.
a Kaneb company

EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE X-GP ETHYLENE PLANT AT FAIRBANKS

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY VOLUME (BBLS)	19000	19000	19000	19000	380000	19000
COST OF SERVICE ($/BBL)	4.282	4.282	4.282	4.282	94.204	4.710
TOTAL REVENUE	29693269	29693269	29693269	29693269	597865380	29693269
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	9500000	9500000	9500000	9500000	190000000	9500000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	25000000	25000000	25000000	25000000	500000000	25000000
TOTAL EXPENSES	34500000	34500000	34500000	34500000	690000000	34500000
INCOME BEFORE TAXES	-4806731	-4806731	-4806731	-4806731	-96134620	-4806731
INVESTMENT TAX CREDIT	0	0	0	0	50000000	2500000
TAX DEPRECIATION	17433922	17433922	17433922	17433922	500000000	25000000
TAXABLE INCOME	2759347	2759347	2759347	2759347	-96134620	-4806731
CURRENT INCOME TAX	1324487	1324487	1324487	1324487	-96144614	-4807231
DEFERRED INCOME TAX	-3631718	-3631718	-3631718	-3631718	-6	0
TOTAL INCOME TAXES	-2307231	-2307231	-2307231	-2307231	-96144620	-4807231
NET INCOME (BOOK)	-2499500	-2499500	-2499500	-2499500	10000	500
SOURCES OF FUNDS						
NET INCOME	-2499500	-2499500	-2499500	-2499500	10000	500
FINANCIAL DEPRECIATION	25000000	25000000	25000000	25000000	500000000	25000000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-3631718	-3631718	-3631718	-3631718	-6	0
NET ADDITIONS TO EQUITY	0	0	0	0	500000000	25000000
TOTAL SOURCES	18868782	18868782	18868782	18868782	1000009994	50000500
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	500000000	25000000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	500000000	25000000
NET CASH GENERATED DURING YEAR	18868782	18868782	18868782	18868782	500009994	25000500
CUMULATIVE NET CASH GENERATED	443403646	462272430	481141212	500009994	6221677679	6110673884
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

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EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GC1 GAS CONDITIONING PLANT AT PRUDHOE FOR 2000 MMSCFD

TIME PERIOD	1981	1982	1983	1984	1985	1986	1987	1988	1989
DAILY VOLUME (MSCFD)	0	0	2000000	2000000	2000000	2000000	2000000	2000000	2000000
COST OF SERVICE ($/MSCFD)	.066	.066	.066	.066	.066	.066	.066	.066	.066
TOTAL REVENUE	0	0	48513931	48513931	48513931	48513931	48513931	48513931	48513931
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	0	0	22505000	22505000	22505000	22505000	22505000	22505000	22505000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	0	0	32200000	32200000	32200000	32200000	32200000	32200000	32200000
TOTAL EXPENSES	0	0	54705000	54705000	54705000	54705000	54705000	54705000	54705000
INCOME BEFORE TAXES	0	0	-6191069	-6191069	-6191069	-6191069	-6191069	-6191069	-6191069
INVESTMENT TAX CREDIT	0	0	64400000	0	0	0	0	0	0
TAX DEPRECIATION	0	0	64400000	57960000	52164000	46947600	42252840	38027556	34224800
TAXABLE INCOME	0	0	-38391069	-31951069	-26155069	-20938669	-16243909	-12018625	-8215869
CURRENT INCOME TAX	0	0	-82827713	-15336513	-12554433	-10050561	-7797076	-5768940	-3943617
DEFERRED INCOME TAX	0	0	15456000	12364800	9582720	7078848	4825363	2797227	971904
TOTAL INCOME TAXES	0	0	-67371713	-2971713	-2971713	-2971713	-2971713	-2971713	-2971713
NET INCOME (BOOK)	0	0	61180644	-3219356	-3219356	-3219356	-3219356	-3219356	-3219356
SOURCES OF FUNDS									
NET INCOME	0	0	61180644	-3219356	-3219356	-3219356	-3219356	-3219356	-3219356
FINANCIAL DEPRECIATION	0	0	32200000	32200000	32200000	32200000	32200000	32200000	32200000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	0	0	15456000	12364800	9582720	7078848	4825363	2797227	971904
NET ADDITIONS TO EQUITY	322000000	322000000	0	0	0	0	0	0	0
TOTAL SOURCES	322000000	322000000	108836644	41345444	38563364	36059492	33806007	31777871	29952548
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	322000000	322000000	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	322000000	322000000	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	0	0	108836644	41345444	38563364	36059492	33806007	31777871	29952548
CUMULATIVE NET CASH GENERATED	0	0	108836644	150182088	188745452	224804944	258610951	290388822	320341370
RATE OF RETURN ON EQUITY	0.00	0.00	9.50	-.50	-.50	-.50	-.50	-.50	-.50

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EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GC1 GAS CONDITIONING PLANT AT PRUDHOE FOR 2000 MMSCFD

TIME PERIOD	1990	1991	1992	1993	1994	1995	1996	1997	1998
DAILY VOLUME (MSCFD)	2000000	2000000	2000000	2000000	2000000	2000000	2000000	2000000	2000000
COST OF SERVICE ($/MSCFD)	.066	.066	.066	.066	.066	.066	.066	.066	.066
TOTAL REVENUE	48513931	48513931	48513931	48513931	48513931	48513931	48513931	48513931	48513931
EXPENSES									
OPERATIONS AND MAINTENANCE EXPENSES	22505000	22505000	22505000	22505000	22505000	22505000	22505000	22505000	22505000
INTEREST EXPENSES	0	0	0	0	0	0	0	0	0
FINANCIAL DEPRECIATION	32200000	32200000	32200000	32200000	32200000	32200000	32200000	32200000	32200000
TOTAL EXPENSES	54705000	54705000	54705000	54705000	54705000	54705000	54705000	54705000	54705000
INCOME BEFORE TAXES	-6191069	-6191069	-6191069	-6191069	-6191069	-6191069	-6191069	-6191069	-6191069
INVESTMENT TAX CREDIT	0	0	0	0	0	0	0	0	0
TAX DEPRECIATION	30802320	27722088	24949879	22454892	22454892	22454892	22454892	22454892	22454892
TAXABLE INCOME	-4793389	-1713157	1059052	3554039	3554039	3554039	3554039	3554039	3554039
CURRENT INCOME TAX	-2300827	-822316	508345	1705939	1705939	1705939	1705939	1705939	1705939
DEFERRED INCOME TAX	-670886	-2149397	-3480058	-4677652	-4677652	-4677652	-4677652	-4677652	-4677652
TOTAL INCOME TAXES	-2971713	-2971713	-2971713	-2971713	-2971713	-2971713	-2971713	-2971713	-2971713
NET INCOME (BOOK)	-3219356	-3219356	-3219356	-3219356	-3219356	-3219356	-3219356	-3219356	-3219356
SOURCES OF FUNDS									
NET INCOME	-3219356	-3219356	-3219356	-3219356	-3219356	-3219356	-3219356	-3219356	-3219356
FINANCIAL DEPRECIATION	32200000	32200000	32200000	32200000	32200000	32200000	32200000	32200000	32200000
LONG TERM BORROWING	0	0	0	0	0	0	0	0	0
DEFERRED INCOME TAXES	-670886	-2149397	-3480058	-4677652	-4677652	-4677652	-4677652	-4677652	-4677652
NET ADDITIONS TO EQUITY	0	0	0	0	0	0	0	0	0
TOTAL SOURCES	28309758	26831247	25500586	24302992	24302992	24302992	24302992	24302992	24302992
APPLICATIONS OF FUNDS									
CAPITAL OUTLAY	0	0	0	0	0	0	0	0	0
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	0	0	0	0	0
NET CASH GENERATED DURING YEAR	28309758	26831247	25500586	24302992	24302992	24302992	24302992	24302992	24302992
CUMULATIVE NET CASH GENERATED	348651128	375482375	400982961	425285953	449588945	473891937	498194929	522497921	546800913
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50	-.50

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EARNINGS AND CASH FLOW PROJECTION CASE

ALASKA ROYALTY GAS AND NGL STUDY (PROJECT 1149)
CASE GC1 GAS CONDITIONING PLANT AT PRUDHOE FOR 2000 MMSCFD

TIME PERIOD	1999	2000	2001	2002	9999	8888
DAILY VOLUME (MSCFD)	2000000	2000000	2000000	2000000	40000000	2000000
COST OF SERVICE ($/MSCFD)	.066	.066	.066	.066	1.452	.073
TOTAL REVENUE	48513931	48513931	48513931	48513931	970278620	48513931
EXPENSES						
OPERATIONS AND MAINTENANCE EXPENSES	22505000	22505000	22505000	22505000	450100000	22505000
INTEREST EXPENSES	0	0	0	0	0	0
FINANCIAL DEPRECIATION	32200000	32200000	32200000	32200000	644000000	32200000
TOTAL EXPENSES	54705000	54705000	54705000	54705000	1094100000	54705000
INCOME BEFORE TAXES	-6191069	-6191069	-6191069	-6191069	-123821380	-6191069
INVESTMENT TAX CREDIT	0	0	0	0	64400000	3220000
TAX DEPRECIATION	22454892	22454892	22454892	22454892	644000003	32200000
TAXABLE INCOME	3554039	3554039	3554039	3554039	-123821383	-6191069
CURRENT INCOME TAX	1705939	1705939	1705939	1705939	-123834261	-6191713
DEFERRED INCOME TAX	-4677652	-4677652	-4677652	-4677652	1	0
TOTAL INCOME TAXES	-2971713	-2971713	-2971713	-2971713	-123834260	-6191713
NET INCOME (BOOK)	-3219356	-3219356	-3219356	-3219356	12880	644
SOURCES OF FUNDS						
NET INCOME	-3219356	-3219356	-3219356	-3219356	12880	644
FINANCIAL DEPRECIATION	32200000	32200000	32200000	32200000	644000000	32200000
LONG TERM BORROWING	0	0	0	0	0	0
DEFERRED INCOME TAXES	-4677652	-4677652	-4677652	-4677652	1	0
NET ADDITIONS TO EQUITY	0	0	0	0	644000000	32200000
TOTAL SOURCES	24302992	24302992	24302992	24302992	12880012881	64400644
APPLICATIONS OF FUNDS						
CAPITAL OUTLAY	0	0	0	0	644000000	32200000
LONG TERM DEBT RETIREMENT	0	0	0	0	0	0
TOTAL APPLICATIONS	0	0	0	0	644000000	32200000
NET CASH GENERATED DURING YEAR	24302992	24302992	24302992	24302992	644012881	32200644
CUMULATIVE NET CASH GENERATED	571103905	595406897	619709889	644012881	80135205	400676045
RATE OF RETURN ON EQUITY	-.50	-.50	-.50	-.50	0.00	0.00

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ALASKA ROYALTY OIL AND GAS
In-State Use - A Developers Guide

Prepared For:
Alaska Royalty Oil and Gas Development Advisory Board

AGO 545264

This guide includes the following components:

A. State Information Needs - Phase I Preliminary Submittal

B. State Information Needs - Phase II Pre-Proposal Submittal

C. Preliminary Siting Criteria

D. State Evaluation Factors

E. State Permitting Requirements

The purpose of the guide is to provide a means for improving the flow of information between the State and a prospective developer, in order to generate a mutually acceptable proposal for in-state facilities making use of Alaska's non-renewable resources. This is not a formal Request for Proposal, nor does it in any way supercede applicable State and local leasing, permitting or regulatory requirements. It is intended solely to:

1. ensure that the State receives, on a timely basis, the necessary information to evaluate a potential development;

2. provide a prospective bidder with information on how the State will be evaluating a project as well as some of the requirements and criteria that a developer will be expected to meet.

A. State Information Needs - Phase I Preliminary Submittal

The preliminary list includes basic types of information that a developer should provide the State in order to initiate the evaluation process. The State will utilize this information to perform a preliminary analysis of the proposed project. The State will make this evaluation available to the developer along with any additional questions and/or concerns.

B. State Information Needs - Phase II Pre-Proposal Submittal

Following the Phase I evaluation, a more detailed analysis of the potential project will be undertaken by the State. A prospective developer will be expected to provide a more specific set of information to satisfy the Phase II evaluation. After satisfactory completion of this phase, efforts can be geared to finalizing a mutually acceptable proposal package and, subsequently, a formal contract.

C. Preliminary Siting Criteria

In order to assist a developer in preparing a description of the proposed facility and locating potential acceptable sites, a preliminary set of State siting criteria is included in the guide.

process. The particular areas of State concern, examples of evaluation factors and agency evaluation responsibilities are described in this internal document. This information should assist developers in understanding how their inputs will be utilized by the State, and the key factors of concern to the State. A more formalized comprehensive interagency project evaluation procedure is now in the process of being developed.

E. State Permitting Requirements

A draft inventory of State permits is included to assist the prospective developer in understanding the scope of required actions necessary prior to development activities. The applications for the appropriate State permits are not a part of the above information flow and evaluation process. If a proposal is accepted, formal applications must be submitted.

A working committee of key State personnel has been established to assist in the information exchange/evaluation process. This group will be available to respond to particular questions, clarify the procedures, provide available data (environmental standards and regulations, site-specific land uses, critical habitat areas, local socioeconomic characteristics, to name just a few), as well as to expedite State evaluation of a proposed project. Following is a tentative timing schedule of activities.

TIME TABLE

(Weeks)

TASKS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
State provides Guid.	○																				
ΦI Data	○	—	—	◎																	
State ΦI Evaluation				◎	—	—	—	◎													
ΦII Data		—	—	—								◎									
State ΦII Eval.												◎	—	—	—	◎					
Formal Proposal Subm.																		△			
Contract Preparation												◎	—	—	—	—	—	—	—	◎	

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INFORMATION NEEDS - DEVELOPER RESPONSIBILITIES

A. Phase I - Preliminary Submittal

B. Phase II - Pre-Proposal Submittal

A. INFORMATION NEEDS - DEVELOPER

PHASE I - PRELIMINARY SUBMITTAL

PHYSICAL CHARACTERISTICS

- General project description - site and logistical support requirements; type, pattern and timing of activities; project phasing; life of facility; product mix/volume;

- Site development concept; potential locations (general rationale) (see: Preliminary Siting Criteria)

- Power needs; raw material needs; access needs and transportation activities; construction material needs - General

- Water utilization requirements

- Technology scale-up requirements

ECONOMIC/FINANCIAL CHARACTERISTICS

- Estimated direct revenues to State and locality (source and timing)

- Financing and ownership schemes

- Labor demands - skills, full-time/part-time/seasonal, short-term/long-term

- Approaches to local and statewide hiring and training

- Preliminary estimates of availability and price of products and/or by-products for local and state-wide use

- Approaches/alternatives for sharing in the responsibility to: provide additional needed public facilities and services; provide in-state service industries; compensate or offset potential negative environmental, economic and fiscal impacts to State and locality

- General information on contribution to local and State economy

- Estimates of type and quantity of inputs demanded by industry

- Expected contributions of State and/or locality - land, infrastructure, tax incentives, below-market-price raw materials, etc.

ENVIRONMENTAL CHARACTERISTICS

- General environmental implications and conflicts expected

- Projected discharges and emissions

- Overview of mitigation strategies/alternatives - spills contingency, air pollution control, site protection, solid waste and waste water disposal, toxic and hazardous substance control, erosion control, etc.

MISC.

- Data collection and study plans and schedule

- Public participation schemes

- Plans for joint government (State and Local) and developer planning and study efforts

- Description of company's organization and affiliations for this project

PHYSICAL CHARACTERISTICS

- Alternative site locations and designs and recommended site and design (with rationale and statement of why recommended site and design are superior)
- Project description (from design to close-down) - specific site and logistical support requirements; operational (including expansion or contraction) plans; product mix/volume; site development plans; provisions for protective or buffer zones
- Readjusted (if necessary) power needs; raw material needs; access needs, transportation loads, density and frequency of transportation activities, types of vehicles and/or vessels; communications requirements; construction material utilization plan and potential sources
- Water consumption and utilization plans; potential sources/conflicts
- Specific technology scale-up requirements
- Convertibility of facilities for other uses (bulk storage, industrial park); potential concurrent uses of facilities (general cargo area, recreational facilities); conversion schemes
- Prior site and construction material negotiations with local landowners/government

ECONOMIC/FINANCIAL CHARACTERISTICS

- Direct revenues to State and locality (timing and sources)
- Updated financing and ownership plans; opportunities for local equity participation
- Updated labor demands - skills, job classifications, full-time/part-time/seasonal, short-term/long-term
- Local and state-wide hiring and training (management and high skills) plans (including phasing and construction/operation separation)
- Refined estimates of availability and price of products and by-products; marketing schemes and/or commitments
- Prior negotiations with suppliers, distributors, transport services, unions

- Commitments for sharing in the responsibility to: (1) provide additional needed public services and facilities; (2) provide in-state service industries; (3) compensate or offset potential negative environmental, economic and fiscal impacts to the State and locality; (4) provide adequate monitoring, surveillance and quality control programs

- Specific expected State and/or local contributions--land, tax incentives, below-market-price raw materials, low-cost power, etc.

ENVIRONMENTAL CHARACTERISTICS

- Volume and timing of all discharges and emissions

- Degree of dredging required (if any) and proposed disposal plans and locations

- Probable primary and secondary impacts; probable adverse effects which cannot be avoided; anticipated irretrievable commitment of resources

- Mitigation strategies - spills contingency; air pollution control; site protection; solid waste and waste water management; revegetation, reclamation and/or restoration schemes; erosion control; stream protection; etc.

- Visual impacts; potential noise and dust problems

- Adequacy (at recommended site) of soils and local geology for solid waste and sewage disposal

- Recycling and conversion schemes; energy conservation and alternative energy use strategies

MISC.

- Monitoring, surveillance and quality control strategies

- Estimates of energy efficiency of project

- Data collection and analysis plans and schedule - base line data; environmental and engineering studies; technology assessment; risk analysis; EIS preparation

- Perceived or expected external constraining factors - Federal permits, NEPA, political opposition, land claims, etc.

- Cost breakdown including: estimated capital/construction/operating costs; training programs; public participation; studies; etc.

- Initial schedule for public inputs (on proposal and potential sites)

- Non-resident employee orientation program plans

C. PRELIMINARY SITING CRITERIA

C. PRELIMINARY SITING CRITERIA

The following preliminary siting criteria can be utilized to assist a prospective developer in: (1) locating potential sites; (2) responding to the information needs of the State:

1. Compatibility - Ensure that facility sites are compatible with existing and projected land and water uses;

2. Consolidation - Utilize existing sites and facilities that are capable of handling anticipated demand while meeting the other siting criteria;

3. Traffic - Avoid siting facilities where the most likely vehicular and/or vessel route(s) would interfere with: community activities; population centers; fishing and/or harbor operations;

4. Access - Facilities should be sited such that access to navigable waterways and recreational areas shall not be foreclosed;

5. Safety - Site fuel, crude oil and LNG storage and transfer areas: downwind from populated areas to reduce the hazard of fire and explosion to human population; at elevations sufficiently above mean sea level to escape the highest tsunami run-up;

6. Pipelines - Align pipeline routes away from active faults, areas of subsidence, glacial surge;

7. Resource Protection - Site facilities so that areas of particular historic, agricultural, scenic, recreational and unique environmental, wildlife habitat, and cultural values will be protected;

8. Site Preparation - Avoid sites where extensive site clearing, dredging and construction in productive wetlands, estuaries, deltas or other sensitive areas would be required;

9. Environmental Management - Site facilities in areas of least biological productivity, diversity and uniqueness and where effluents, emissions and spills can be controlled or contained easily;

10. Air Quality - Site facilities where the probability of chronic air quality problems would be low;

11. Water Quality/Supply - Site facilities where the probability of water quality degradation would be low and where the existing water supply would not be adversely affected;

12. Local Preference - Locate facilities where local preferences are supportive of such development.

D. Examples of State Evaluation Factors

AREA OF CONCERN

Impact on governmental resources and responsibilities

EVALUATION FACTORS (Examples)

- net governmental fiscal balance over time--local and state-wide (particularly revenue shortfalls)
- change in quality and quantity (per capita) of public services or goods
- long-term convertability of facilities for public or private use; potentials for concurrent use

AGENCY RESPONSIBILITY

Department of Revenue, Department of Community and Regional Affairs, Division of Budget and Management, Department of Public Works, Department of Highways

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AREA OF CONCERN

Direct contribution to local and state-wide private economy (includes changes resulting from the development itself and activities accompanying it due to expanded markets)

EVALUATION FACTORS (Examples)

- change in real per capita income and product (due to project and attendent service facility expansions)
- short- and long-run price impacts (e.g. short-run shortages of private goods or facilities; long-run private economies of scale, increased competition, changes in transportation costs)

AGENCY RESPONSIBILITY

Department of Commerce and Economic Development, Department of Revenue

AREA OF CONCERN

Employment

EVALUATION FACTORS (Examples)

- change in local and regional (% and #) employed, unemployed, under-employed Alaskans
- type, level and salaries of jobs
- time characteristics of jobs and their distribution (short- vs. long-term)
- level of training and Alaska hire commitment (amount of labor imported)
- degree to which manpower training dovetails with timing of employment requirements

AGENCY RESPONSIBILITY

Department of Labor, Department of Commerce and Economic Development, Department of Community and Regional Affairs

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AREA OF CONCERN

Distributional aspects and implications of the development

EVALUATION FACTORS (Examples)

- distribution of income and jobs associated with the project among groups (in-state vs. out-of-state; local vs. state-wide, current residents vs. in-migrants; Native/non-Native; income classes; sectors of the economy)
- opportunities for local participation--investment
- ownership of assets (in-state vs. out-of-state)
- changes in land value and ownership

AGENCY RESPONSIBILITY

Department of Community and Regional Affairs, Department of Revenue, Department of Labor, Department of Commerce and Economic Development

AREA OF CONCERN

Indirect or spinoff economic activities (the primary project's impact on future economic developments)

EVALUATION FACTORS (Examples)

- the possibility of related developments (either producing inputs for the production process of the primary industry or utilizing outputs of the primary industry)
- size and impact of such development (measured in ways similar to economic impact of primary industry)

AGENCY RESPONSIBILITY

Department of Commerce and Economic Development, Department of Community and Regional Affairs, Department of Revenue

AREA OF CONCERN

Lifestyle changes and social conflicts

EVALUATION FACTORS (Examples)

- the potential for value conflicts between local residents and expected in-migrants
- potential for cross-cultural conflicts between local residents and expected in-migrants
- conflict with subsistence use of wildlife
- growth management capability
- degree of local control and self-determination
- impact on quality of rural lifestyle or village lifestyle amenities
- public sentiment (local and state-wide)

AGENCY RESPONSIBILITY

Department of Community and Regional Affairs, Department of Health and Social Services, Department of Education, Department of Fish and Game

AREA OF CONCERN

Natural resources and land use alternatives

EVALUATION FACTORS (Examples)

- impact on forest sustained yield
- impact on fishery resources/areas of high biologic-commercial productivity
- impact on mineral extraction (including oil and gas)
- impact on available water supply
- impact on agricultural potentials
- impact on fish and wildlife habitats/populations
- impact on recreational potentials
- impact on wilderness, historic, scenic and sensitive environmental areas
- construction material demands

AGENCY RESPONSIBILITY

Department of Natural Resources, Department of Fish & Game, Department of Environmental Conservation, Department of Commerce and Economic Development

AREA OF CONCERN

Safety and Health

EVALUATION FACTORS (Examples)

- air, water and noise pollution (degree of localization; impact on human settlements, environmentally sensitive areas, highly scenic areas)
- dust, spills, thermal discharges (same as above)
- safeguards for transport and storage of toxic and hazardous substances
- drainage pattern impacts
- adequacy of soils and local geology for solid waste and sewage disposal
- compliance with State, local, and Federal environmental standards and criteria

AGENCY RESPONSIBILITY

Department of Environmental Conservation, Department of Fish and Game, Department of Natural Resources, Department of Health and Social Services

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AREA OF CONCERN

Environmental Management

EVALUATION FACTORS (Examples)

- monitoring, surveillance and quality control strategies
- development time frame (to build up environmental protection capabilities)
- degree of commitment of irretrievable resources and/or irreversible consequences
- environmental data sufficiency
- degree of internalization of environmental costs

AGENCY RESPONSIBILITY

Department of Environmental Conservation, Department of Fish and Game

AREA OF CONCERN

Construction feasibility/probability of construction delays/cost overrun potentials

EVALUATION FACTORS (Examples)

- technology requirements
- data base/engineering studies sufficiency
- infringement on high hazard areas
- legal and/or regulatory constraints
- degree of consolidation/concentration of facilities
- external constraints (political, economic, logistic)
- expansion potentials
- energy efficiency of project/energy conservation measures
- use of alternative energy sources

AGENCY RESPONSIBILITY

All departments

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Permits Issued by
the Department of Environmental Conservation

1. Waste Water Disposal Permit

A person conducting any operation which results in the disposal of solid or liquid waste material into the waters or onto the lands of the State must procure a permit from the Department of Environmental Conservation before disposing of the waste material. The permit must be obtained for direct disposal and for disposal into publicly operated sewerage systems. The permit does not apply to persons discharging only domestic sewage into the sewerage system.

Procedure: Permit applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor. See Department of Environmental Conservation "Contacts List" in appendix.

Requirements: The Department may require the submission of plans for sewage and industrial waste disposal or treatment or both for publicly or privately owned or operated industrial establishments, community, public or private property subdivision or development.

Authority for Permit:
* AS 46.03.100. Waste disposal permit.
* AS 46.03.090. Plans for pollution disposal.
* AS 46.03.110 and 720. Waste disposal permit procedure.
* 18. AAC. 72.030. Pretreatment.

Criteria for Issuance: AAC Title 18, Chapter 70 and 72.

2. Solid Waste Disposal Permit

No person may establish, modify or operate a solid waste disposal facility without a permit, except the following:

1) a single family or duplex residence on which solid waste is generated and disposed of, on-premises;

2) a farm on which solid waste generated from the operation of that farm is disposed; and

3) incinerator facilities having a total rated capacity of less than 200 pounds of solid waste per hour.

Procedure: Permit applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor for appropriate forms. Application for permit shall contain:

1) completed permit application forms;

2) detailed plans and specifications for facility;

3) certification of compliance with local ordinances and zoning requirements;

4) a report detailing the proposed methods for operation, population of area to be served, characteristics, quantity and source of material to be processed; and

5) 60 days public notice and public hearing.

Requirements: Detailed plans and specifications for the facility are required, as outlined above.

Authority for Permit:
* AS 46.03.020. Powers of the department.
* AS 46.03.100. Waste disposal permit.

Criteria for Issuance: AAC Title 18, Chapter 60, Solid Waste Management.

3. Air Emissions Permit

A permit is required to operate a facility capable of emitting quantities of pollutants injurious to human health or welfare, animal or plant life or property.

Procudure: Applicant should contact the Department of Environmental Conservation Regional Supervisor.

Requirements: No person may construct or modify a facility requiring a permit to operate until detailed plans and specifications are submitted to the Department and approved.

Authority for Permit:

* AS 46.03.010. Declaration of policy.
* AS 46.03.140. Emission control requirements.
* AS 46.03.150. Classification and reporting.
* AS 46.03.160. Additional contaminant control measures.
* AS 46.03.170. Variances.
* 18 AAC 50.120. Permit to operate.

Citeria for Issuance:

* 18 AAC 50.020. Ambient Air Quality Standards.
* 18 AAC 50.030. Open Burning.
* 18 AAC 50.040. Incinerators.
* 18 AAC 50.050. Industrial Processes and Fuel Burning Equipment.
* 18 AAC 50.120. Permit to operate.

4. Pesticides Permit

No person may, without a permit issued by the Department, apply or cause to be applied any pesticide or broadcast chemical.

Procedure: The permit applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor for the appropriate form.

Requirements: An application for a permit to use pesticides shall include information relating to the name of the pest to be controlled, the type of formulation to be used, and percentage of active ingredients, the quantity of active ingredients to be applied per unit area, and other information.

Authority for Permit:

* AS 46.03.320. Authority.
* AAC Title 18, Chaper 90. Pesticide and Broadcast Chemical Control.

Criteria for Issuance:

* AAC Title 18, Chapter 90. Pesticide and Broadcast Chemical Control.

5. Surface Oiling Permit

No person may discharge, cause to be discharged, or permit the discharge of oil, asphalt, bitumen or a residuary product of petroleum onto the lands of the State unless that person has been granted a surface oiling permit.

Procedure: Applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor for the appropriate form.

Requirements: An application for a surface oiling permit shall be made on forms prescribed by the Department and shall contain information considered necessary to the Department.

Authority for Permit:
* 18 AAC 75.010. Surface Oiling Permit.
* AS 46.03.020. Powers of the Department.
* AS 46.03.740. Oil pollution.

Criteria for Issuance:
* AAC Title 18, Chapter 75.

6. Open Burning Permit

Open burning for disposal of oils, oily waters, asphalts and tars and similar wasted materials is prohibited unless conducted under a permit from the Department.

Procedure: Applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor.

Requirements: Emission data may be required prior to grant of the permit.

Authority for Permit:
* AS 46.3.020. Powers of the Department.
* 18 AAC 50.030. Open Burning.
* 18 AAC 50.120. Permit to Operate.

Criteria for Issuance:
* 18 AAC 50.020. Ambient Air Quality Standards.

7. Anadromous Fish Protection Permit

If a person or governmental agency desires to construct a hydraulic project, or use, divert, obstruct, pollute, or change the natural flow or bed of a specified river, lake or stream, or use wheeled, tracked, or excavating equipment or log-dragging equipment in the bed of the specified river, lake, or stream, the person or governmental agency shall notify the Department of Fish and Game before the beginning of the construction or use.

Procedure: Permit applicant should contact the Department of Fish and Game Regional Habitat Supervisor for his region. See Department of Fish and Game "Contacts List" in appendix.

Requirements: If the Commissioner of the Department of Fish and Game determines to do so, he shall require the person or government agency to submit to him full plans and specifications for the proper protection of fish and game in connection with the construction or work, or in connection with the use, and the approximate date the construction or work or use will begin, and shall require the person to obtain written approval from him as to the sufficiency of the plans and specifications before the proposed construction or use is begun.

Authority for Permit:
* AS 16.05.870. Protection of Fish and Game.
* 5 AAC 95.010. Waters important to Anadromous Fish.

Copies of the List of Waters Important to Anadromous Fish or of information contained therein may be obtained by writing the Lieutenant Governor or the Department of Fish and Game, Habitat Protection Section, Subport Building, Juneau, Alaska, 99801, or may be obtained from ADF&G Regional Habitat Supervisors.

8. Critical Habitat Areas Permit

Before the use, lease or other disposal of land under private ownership or State jurisdiction and control, within State Fish and Game critical habitat areas, the person or responsible State department or agency shall notify the Department of Fish and Game.

Procedure: The responsible person should contact the Department of Fish and Game Regional Habitat Supervisor for his region.

Requirements: If the Board of Fish and Game so determines, it shall instruct the Commissioner to require the person or governmental agency to submit full plans for the anticipated use, full plans and specifications of proposed construction work, complete plans and specifications for the proper protection of fish and game, and the approximate date when the construction work is to commence, and shall require the person or governmental agency to obtain the written approval of the Commissioner as to the sufficiency of the plans and specifications before construction is commenced.

Authority for Permit:
* AS 16.20.250. Multiple land use.
* AS 16.20.260. Submission of plans and specifications.

Criteria for Issuance:
Determination of Board of Fish and Game.

9. State Game Refuge Land Use Permit

Where the use, lease or disposal of real property in State game refuges is under the control or jurisdiction of the State, whether through Federal permit or State ownership, the responsible State department or agency shall notify the Department of Fish and Game before initiating any use, lease or disposal of real property.

Procedure: The responsible State department or agency should contact the Commissioner of the Department of Fish and Game.

Requirements: If the Commissioner so determines, he may require the person or governmental agency to submit full plans and specifications for the anticipated use, full plans and specifications of proposed construction work, complete plans and specifications for the proper protection of fish and game, and the approximate date when the construction work is to commence, and shall require the person or agency to obtain written approval of the Commissioner as to the sufficiency of the plans and specifications before construction is commenced.

Authority for Permit:
* AS 16.20.050. Multiple land use.
* AS 16.20.060. Submission of plans and specifications.

Criteria for Issuance:
Determination of the Commissioner.

10. Encroachment Permit

An encroachment may be constructed, placed, changed or maintained across or along a highway but only in accordance with regulations adopted by the Department. No encroachment may be constructed, placed, maintained or changed until it is duly authorized by a written permit issued by the Department of Highways.

Procudure: Applicant should contact the Department of Highways District Engineer for his region. See Department of Highways "Contact List" in appendix.

Requirements: During routine maintenance patrol, road and weather condition inspection, or at regular intervals as deemed necessary, maintenance personnel shall inspect right-of-way for encroachments. When an encroachment is found, District Right-of-Way will make a recommendation to the District Engineer as to whether the encroachment should be permitted or removed.

Authority for Permit:
* AS 19.25.200. Encroachment permits.

Criteria for Issuance: State of Alaska Department of Highways Standard Operating Procedure, S.O.P. #0000-14.

11. Utility Permit

An electric transmission, telephone, or telegraph line, pole line, railway, ditch, sewer, water, heat, or gas main, flume, or other structure which by law may be constructed, placed or maintained across or along a highway by a person or political subdivision may be maintained or constructed only in accordance with regulations prescribed by the Department. No utility project of this nature may be undertaken until it is authorized by a written permit issued by the Department.

Procedure: Applicant should contact the Department of Highways District Engineer in his region.

Requirements: Plans are required.

Authority for Permit:
* AS 19.25.010. Use of right-of-ways for utilities.
* 17 AAC 15.010. Application for utility permit.
* 17 AAC 15.020. Utility Permit.

Criteria for Issuance: See Alaska Administrative Code 17 AAC 15.010-020.

12. Driveway Permit

Before starting the construction of driveways or performing any work upon the right-of-way, the property owner shall first apply for and obtain a revocable permit from the Department of Highways.

Procedure: Applicant should contact the Department of Highways District Engineer for his region.

Requirements: Applicant must perform all work in accordance with permit.

Authority for Permit:
* 17 AAC 10.020. Driveways and Road Approaches.
* AS 19.05.020. Regulations.

Criteria for Issuance:
* 17 AAC 10.020. Driveways and Road Approaches.

Driveway Regulations can be obtained at Department of Highways District Offices.

13. Overweight - Oversize Permit

The Department of Highways, with respect to highways under its jurisdiction, may:

1) establish limitations on weight and load of vehicles;

2) issue special written permits authorizing the operation of overweight vehicles; and

3) prohibit the operation or impose restrictions on vehicular use of highways during certain seasons of the year.

Procedure: Applicant should contact the Department of Highways District Office for application form 14-156.

Requirements: Permits may be issued for operation of oversize-overweight vehicles when:

1) Application has been made in writing, good cause has been shown and all pertinent requirements are met;

2) The applicant has completely described his load and vehicle route and time of travel;

3) The applicant has certified that the load cannot "reasonably" be dismantled or disassembled to meet the legal load and size requirements. Disassembly may be required by the District Engineer to assure the safety of the traveling public or the highways and its appurtenances;

4) The applicant has affirmed that the vehicle or vehicles meet all requirements of the Alaska Department of Commerce and the Transportation Commission; and

5) The proposed move will not be detrimental to the public safety or damage the roadway structure or bridges as determined under State requirements.

Authority for Permit:

* AS 19.10.060. Regulation of weight and load of vehicles and use of highways during certain seasons.
* AS 28.05.020. Authority for Commissioner of Highways to adopt regulations.
* 17 AAC 25.010. Penalty and Exclusion.
* 17 AAC 25.020. Width of Vehicles.
* 17 AAC 25.030. Height and Length of Vehicles and Loads.

Criteria for Issuance: * 17 AAC 25.010-030.

Alaska Oversize and Overweight Permit Movements State of Alaska, Department of Highways, Maintenance Division, P. O. Box 1467, Juneau, Alaska, 99802.

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Parks, Recreation and Public Use — Special Land Use Permits

14. Investigation and Collection Permits

A person qualified under 11 AAC 16.040 may apply to the director upon an application form provided by him for a permit to investigate or collect historic, prehistoric or archaeological resources of the State.

Procedure: Applicant should contact the Department of Natural Resources District Office. See "Contacts List" in appendix.

Requirements: Person must qualify as having some experience in anthropology or field archaeology.

Authority for Permit:
* AS 41.20.040. Division within Department of Natural Resources.
* AS 41.35.050. Regulations.
* AS 41.35.080. Permits.
* 11 AAC 16.030. Investigation and Collection Permits.

Criteria for Issuance:
* 11 AAC 16.040. Qualified Person.

15. State Park Incompatible Use Permit

Incompatible uses (e.g., mineral exploration, cutting of timber) of public lands within a State park are allowable only with a permit. Permits will be issued where it is determined that the ecology of the area will not be damaged and public use values will be protected.

Procedure: Applicant should contact the Department of Natural Resources District Office.

Requirements: Contact District Office.

Authority for Permit:
* AS 41.20.020. Duties of Department of Natural Resources.
* AS 41.20.040. Division within Department of Natural Resources.
* 11 AAC 18.010. State Park Incompatible Uses.

Criteria for Issuance:
* 11 AAC 18.010. State Park Incompatible Uses.

16. Access Routes Permit

A permit is required to gain an access route across State park land or water to privately owned property wholly or partially within a State park.

Procedure: Contact the Department of Natural Resources District Office.

Requirements: Permittee must construct access route according to specifications provided by the director.

Authority for Permit:
* AS 41.20.020. Duties of the Department of Natural Resources.
* AS 41.20.040. Division within the Department of Natural Resources.
* 11 AAC 18.020. Access Routes.

Criteria for Issuance: Determined by Director of Parks and Recreation.

17. Drilling Permits

A person wishing to drill or deepen any well for oil and gas must first submit an application accompanied with a fee of $100.00, and then obtain permit.

Procedure: Contact the Department of Natural Resources -- Minerals and Energy Division. See "Contacts List" in appendix.

Requirements: $100.00 fee. A survey plat must accompany the application showing the precise location of the drilling activity.

Authority for Permit:
* AC 31.05.090. Permits and fees to drill wells.
* 11 AAC 22.005. Permit to Drill or Deepen.

Criteria for Issuance:
* 11 AAC 22.005. Permit to Drill or Deepen.

18. Drilling Deviation Permit

A permit is required before a well operator may intentionally deviate from the vertical, except for the purposes of straightening the hole, side-tracking junk, or correcting mechanical difficulties.

Procedure: Contact the Department of Natural Resources - Minerals and Energy Division.

Requirements: Application for permit shall include:

1) surface and proposed producing interval locations in terms of distances from lease and section boundaries;

2) reason for deviation;

3) list of affected operators and a showing that each has been furnished a copy of the application by certified mail, or a showing that the applicant is the only affected operator; and

4) neat and accurate plat of lease and all affected operators and the surface and proposed producing interval locations as well.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.050. Deviation.

Criteria for Issuance:
* 11 AAC 22.050. Deviation.

19. Well Spacing Permit

A person must apply for and receive an exception to the well spacing regulations before deviation from the regulations is allowed.

Procedure: Permit applicant should contact the Department of Natural Resources Minerals and Energy Division.

Requirements: An application must indicate the affected operators, and include a plat of the proposed action.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.055. Well Spacing.

Criteria for Issuance:
* 11 AAC 22.055. Well Spacing.

20. Notice of Abandonment

Before beginning work on any well, notice of intention to abandon must be filed, and approval must be given.

Procedure: Person should contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Notice must show the reason for abandonment and must be accompanied by a detailed statement of proposed work including such information as kind, location, size of plugs, and plans for mudding, etc.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.100. Notice.

Criteria for Issuance:
* 11 AAC 22.100. Notice.

21. Plugging Procedure

To deviate from the plugging procedure set up in the regulations, approval upon application must be obtained.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Follow procedures outlined in 11 AAC 22.110., Plugging Procedures.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.110. Plugging Procedure.

Criteria for Issuance:
* 11 AAC 22.110. Plugging Procedure.

22. Well Marker

In order to waive well marker requirements, the surface owner must request and receive approval.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and Duties of the Department.
* 11 AAC 22.120. Well Marker.

23. Water Wells

Written authority for a well to be used as a fresh water well must be applied for and approved.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact Minerals and Energy Division.

Authority for Permit:

* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.140. Water Wells.

24. Temporary Abandonment

Approval is required if a well is to be temporarily abandoned.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: If approved, a plug must be placed at the top and bottom of the well casing in such a manner as to prevent the intrusion of any foreign matter into the well. The well shall be left full of mud.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.150. Temporary Abandonment.

25. Location Cleanup

Time extension must be obtained for the well operator to deviate from the cleanup regulations.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact the Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.170. Location Cleanup.

24. Temporary Abandonment

Approval is required if a well is to be temporarily abandoned.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: If approved, a plug must be placed at the top and bottom of the well casing in such a manner as to prevent the intrusion of any foreign matter into the well. The well shall be left full of mud.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.150. Temporary Abandonment.

25. Location Cleanup

Time extension must be obtained for the well operator to deviate from the cleanup regulations.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact the Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.170. Location Cleanup.

26. Multiple Completion of Wells

No well may be put into multiple production without approval.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Approval will require evidence of adequate and complete separation as ascertained by pressure or circulation tests.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.210. Multiple Completion of Wells.

27. Commingling of Production

An order approving commingling in the same well bore of production from two or more wells must be obtained before such practice is permitted.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Proposing operator must certify that contact has been made with the affected parties and no opposition is furnished to committee within 15 days.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.215. Commingling of Production.

28. Earthen Reservoirs

Permission must be obtained to store oil in earthen pits.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.220. Earthen Reservoirs.

29. Disposal of Brine and Other Wastes

Permission is required for the disposal of salt water.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: It must be shown that the disposal of salt water will not contaminate fresh water or endanger other natural resources.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.250. Disposal of Brine and Other Wastes.

Note: The items listed under the above heading involve the need for administrative approvals and orders from the Oil and Gas Conservation Committee. These approvals on various well operations are, in effect, permits to do various types of work once a well is completed or to abandon a well. However, the forms and procedures do not bear the title permit.

30. Additional Recovery Methods

A permit is required for any method of pressure maintenance or methods of additional recovery used other than primary recovery techniques.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Application must contain a plat showing the unit, lease or group of leases within the proposal project, along with other related information.

Authority for Permit:
* AS 31.05.020. Waste Prohibited.
* 11 AAC 22.400. Application.

31. Development Work

No development work shall be done on coal deposits on State lands without the advance approval of the State geologist.

Procedure: Contact the Department of Natural Resources - Minerals and Energy Division.

Requirements: Contact the Minerals and Energy Division.

Authority for Permit:
* AS 27.20.005. Purposes.
* AS 27.20.010. Rules and Regulations.
* 11 AAC 46.010. Advance Approval.

32. Right-of-Way or Easement Permit

The Division of Lands Director may issue permits for roads, trails, ditches, pipelines, drill sites, log storage, telephone and transmission lines or similar uses or improvements.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: Plats are required, as well as an application fee.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.035. Powers and duties of the Director.
* AS 38.05.075. Leasing procedures.
* AS 38.05.330. Permits.
* 11 AAC 58.200. Right-of-Way or Easement Permit.

33. Special Land Use Permit

The Director of the Division of Lands may issue special land use permits on such terms and conditions as he deems to be in the interests of Alaska.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: Provide information as to the nature of the proposed activity.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.035. Powers and duties of the Director.
* AS 38.05.075. Leasing procedures.
* 11 AAC 58.210. Special Land Use Permit.

34. Tidelands Permit

The Director of the Division of Lands may issue permits for the improvement or use of State-owned tidelands, or for personal use of materials. The first preference in the granting of such permits will be granted to the upland owner over other nonpreference applicants for the use of tideland and contiguous submerged land seaward of the upland property.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: A $20.00 filing fee is required. Upon receipt of the application, the Director shall, within 60 days, express his approval or disapproval, and shall state his reasons. Each upland owner may protest the issuance of the permit. No permits shall be issued that will deny the upland owner reasonable access to tide waters during the course of or completion of the work.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.320. Occupied tidelands and submerged lands.
* 11 AAC 62.710. Tidelands Permits.

Criteria for Issuance:
* 11 AAC 62.720. Application for Tideland Permits.

35. Tideland Right-of-Way and/or Easement Permits

Permits may be issued by the Division of Lands Director for secondary roads, trails, ditches, pipelines, telephone transmission lines, log storage, oil well drilling sites, and production facilities for the purposes of recovering minerals from adjacent lands under valid lease and other similar uses or improvements. First preference shall be granted to the upland owner.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: An applicant must furnish the name and address of the upland owner.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.320. Occupied Tidelands and submerged lands.
* 11 AAC 62.810. Tidelands Right-of-Way and/or Easement Permits.

Criteria for Issuance:

* 11 AAC 62.810. Tideland Right-of-Way and/or Easement Permits.

36. Limited Personal Use Permit

Permits may be granted for a limited quantity of materials for personal use, and such materials shall not be sold. The director shall, in each permit, specify the quantity of material allowed but in no event shall the quantity exceed 100 cubic yards. The permits are for temporary use only.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:

* AS 38.05.020. Authorities and duties of the Commissioner.
* AS 38.05.320. Occupied Tidelands and submerged lands.
* 11 AAC 62.820. Limited Personal Use Permit.

37. Permit to Appropriate Water

Any person who desires to appropriate otherwise unappropriated waters of the State shall make application for a permit to appropriate water.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: An application for a permit to appropriate water shall include:

1) location of source from which water is to be appropriated;

2) place where the appropriated water will be of beneficial use;

3) quantity of water to be appropriated;

4) proposed use of water to be appropriated; and

5) description of the proposed means of diversion.

Authority for Permit:

* AS 46.15.040. Right to appropriate.
* AS 46.15.060. Existing rights.
* AS 46.15.070. Notices; objections.
* AS 46.15.135. Determination of existing rights.
* AS 46.15.180. Crimes.
* 11 AAC 72.050. Application for Permit to Appropriate.

38. Dam Construction

An application for a permit to appropriate water must include plans and specifications for any dam that may be built.

Procedure: Applicant must contact the nearest District Office of the Department of Natural Resources.

Requirements: Plans are required. If necessary, the Director may request that the applicant obtain an independent appraisal of the plans and specifications from a qualified engineer acceptable to the Director.

Authority for Permit:

* AS 46.15.040. Right to appropriate.
* AS 46.15.060. Existing rights.
* AS 46.15.070. Notices; objections.
* AS 46.15.135. Determination of existing rights.
* AS 46.15.180. Crimes.
* 11 AAC 72.060. Dam Construction.

39. Application for Preferred Use

The holder of a preferred use status may make an application for a permit to appropriate either unappropriated or previously unappropriated waters or both.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: A $20.00 filing fee is required. The applicant must provide the names and addresses of all holders of existing water rights, permits to appropriate or certificates of appropriation whose rights to water would be reduced, or in times of water scarcity, could be reduced by the diversion of water to the preferred use. Also required are certified copies of executed agreements between the holder of preferred use status and all other persons names as required to provide compensation for loss of previously appropriated water, or certified copies of any court orders which direct the amount and manner of compensation paid.

Authority for Permit:

* AS 46.15.040. Right to appropriate.
* AS 46.15.060. Existing rights.
* AS 46.15.070. Notices; objections.
* AS 46.15.135. Determination of existing rights.
* AS 46.15.180. Crimes.
* 11 AAC 72.160. Application for Preferred Use.

40. Use of Timber and Materials

Gravel, sand, and rock used by a purchaser in connection with a sale of timber may be acquired under a special permit issued in connection with the timber sale.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:

* AS 38.05.020. Authorities and duties of the Commissioner.
* AS 38.05.110. Sale of timber and materials.
* AS 38.05.115. Limitations and conditions of sale.
* AS 38.05.120. Disposal procedure.
* 11 AAC 76.185. Use of Timber and Materials.

41. Authorization for Transportation Facilities

Timber purchasers must obtain a permit for use of tidelands under State jurisdiction which are necessary for dumping, sorting, storage and rafting of timber cut from State sales.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Location and design of roads or access will be approved by the Director prior to construction.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.110. Sale of timber and materials.
* As 38.05.115. Limitations and conditions of sale.
* AS 38.05.120. Disposal procedure.
* 11 AAC 76.205. Authorization for Transportation Facilities.

42. Special Material Use Permit

The Director may issue special material use permits for periods not to exceed one year upon such terms and conditions as he deems to be in the interest of the State.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.115. Limitations and conditions of sale.
* AS 38.05.120. Disposal procedure.
* 11 AAC 76.540. Special Material Use Permit.

43. Noncompetitive Procedures

Applications for noncompetitive leases on permits for a mineral may be filed on any noncompetitive lands opened for leasing of that mineral.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.135. Generally.
* AS 38.05.145. Leasing Procedure.

44. Coal Prospecting Permit

A permit is required for prospecting or exploration work necessary to determine the existence of coal deposits in an unclaimed and undeveloped area. The permit is for a period of two years, and not to exceed 5,120 acres.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.035. Powers and duties of the Director.
* AS 38.05.145. Leasing procedure.
* AS 38.05.150. Coal.
* 11 AAC 84.115. Prospecting Permits Operations.

45. Sodium Leasing Method

Prospecting permits for lands not known to contain valuable deposits of sodium are issued noncompetitively.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 30.05.145. Leasing procedure.
* 11 AAC 84.400. Sodium Leasing Method.

46. Potassium Leasing Method

Prospecting permits authorized for lands not known to contain valuable deposits of potassium compounds are issued noncompetitively.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.145. Leasing procedure.
* 11 AAC 84.600. Potassium Leasing Method.

47. Geothermal Resources Leasing Method

Prospecting permits authorized for lands which have not been classified as geothermal resources areas are issued noncompetitively.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.145. Leasing procedure.
* 11 AAC 84.700. Geothermal Resources Leasing Method.

48. Tide and Submerged Lands

The exclusive right to prospect for deposits of minerals in or on tide and submerged lands may be granted by the Director of the Division of Lands.

Prodecure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Applicant must meet qualifications outlined in AS 38.05.190.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.250. Tide and submerged lands.
* 11 AAC 86.500; 510; 530; and 540. Permit Applications, Acceptable Permit Work, Conversion of an Offshore Prospecting Permit to a Mining Lease, and Lease Rental.

49. Surface Use Permits

A permit is required for millsite and tailings removal.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: A reasonable rate or fee schedule shall be charged for such use.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.255. Surface use.
* 11 AAC 86.600. Millsites.

50. Burning Permit

A burning permit is required during the fire season for the burning of any materials in the area designated by the Department of Natural Resources.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: The applicant shall provide information as to the type, location, size and person in charge of the burning; the area and material to be burned; and the number of persons controlling the burn. Prior to the issuance of the permit, an inspection may be required of the area to be burned.

Authority for Permit:
* AS 41.15.050. Fire Season.
* 11 AAC 92.010. Permit.

51. Operations on State Land Requiring Permits

A permit is required for the following activities on State lands: 1) activity requiring; a) the use of explosives; b) the use of hydraulic prospecting or mining equipment and/or methods; c) drilling to a depth in excess of 300 feet; and (2) activity which the Director of the Division of Lands determines may result in harm to lands having special scenic, historic, archaeological, scientific, biological, recreational or special resource value.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.035. Powers and duties of the Director.
* 11 AAC 96.010. Operations Requiring permits.

50. Burning Permit

A burning permit is required during the fire season for the burning of any materials in the area designated by the Department of Natural Resources.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: The applicant shall provide information as to the type, location, size and person in charge of the burning; the area and material to be burned; and the number of persons controlling the burn. Prior to the issuance of the permit, an inspection may be required of the area to be burned.

Authority for Permit:
* AS 41.15.050. Fire Season.
* 11 AAC 92.010. Permit.

51. Operations on State Land Requiring Permits

A permit is required for the following activities on State lands: 1) activity requiring; a) the use of explosives; b) the use of hydraulic prospecting or mining equipment and/or methods; c) drilling to a depth in excess of 300 feet; and (2) activity which the Director of the Division of Lands determines may result in harm to lands having special scenic, historic, archaeological, scientific, biological, recreational or special resource value.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.035. Powers and duties of the Director.
* 11 AAC 96.010. Operations Requiring permits.

52. Subleases of State Land

A permit is required from the Director of the Division of Lands prior to the sublease or assignment of any portion of State-leased land.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.095. Subleases.

53. Right-of-Way Permits

The Director of the Division of Lands may issue permits, right-of-ways or easements on State land for secondary roads, trails, ditches, transmission lines and distribution pipelines, field-gathering lines, telephone and transmission lines, log storage, oil well drilling sites, and production facilities for the purposes of recovering minerals from adjacent lands under valid lease, and other similar uses or improvements for the limited use or timber or materials.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permits
* AS 38.05.330. Permits.

54. Abandonment of or Reduction or Impairment of Service of Pipeline by Leasee Carrier.

No leasee may abandon or reduce or impair service of any portion of a pipeline that is on State land or subject to lease without first receiving a certificate from the Commissioner that the action is in accordance with the terms of the lease.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact the Minerals and Energy Divison.

Authority for Permit:
* AS 38.35.030. Abandonment of, or reduction or impairment of, service of pipeline by leasee carrier.

55. Applications for Right-of-Way Leases and Certificates

Persons desiring to own a pipeline which is proposed to be located in whole or in part on State land shall apply for a noncompetitive right-of-way lease of this land and a certificate that the construction, operation, transportation, service, or sale is in accordance with the lease.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit

* AS 38.35.050. Applications for right-of-way leases and certificates.

56. Preservation of Archaeological Resources

If the State archaeologist determines that archaeological sites or remains will be adversely affected by public construction, the project cannot commence until the State archaeologist performs necessary investigations.

Procedure: Contact the Division of Parks and Recreation.

Requirements: Contact the Division of Parks and Recreation.

Authority for Permit:

* AS 41.35.070. Perservation of historic, prehistoric, and archaeological resources threatened by construction.

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Department of Environmental Conservation Contacts List

Central Office
Department of Environmental
Conservation
Pouch O
Juneau, Alaska 99811

Northern Regional Office

Doug Lowery
Regional Environmental Supervisor
Department of Environmental
Conservation
P. O. Box 1601
675 Seventh Avenue
Fairbanks, Alaska 99707

Phone: 452-1714

Southcentral Regional Office

Kyle Cherry
Regional Environmental Supervisor
Department of Environmental
Conservation
Rm. 1206, MacKay Building
338 Denali Street
Anchorage, Alaska 99501

Phone: 274-5527

Prince William Sound Regional Office

Randy Bayliss
Regional Environmental Supervisor
Department of Environmental
Conservation
Pouch E
Valdez, Alaska 99686

Phone: 835-4698

Southeast Regional Office

Deena Henkins
Regional Environmental Supervisor
Department of Environmental
Conservation
Pouch OA (Mayflower Building, Dou
Juneau, Alaska 99811

Phone: 364-2165

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Department of Fish and Game Contacts List

Region I

Rick Reed
Regional Supervisor
Habitat Protection Section
Department of Fish and Game
210 Ferry Way
Juneau, Alaska 99801

Phone: 586-6630

Region II

Tom Trent
Habitat Protection Section
Department of Fish and Game
333 Raspberry Road
Anchorage, Alaska 99502

Phone: 344-0541

Region III

J. Scott Grundy
Regional Supervisor
Habitat Protection Section
Department of Fish and Game
1300 College Road
Fairbanks, Alaska 99701

Phone: 452-1531

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Department of Highways Contacts List

District Engineers

Southeastern - Region III

Wallace K. Williams
Southeastern District Engineer
Department of Highways
6860 Glacier Highway
P. O. Box 3-1000
Juneau, Alaska 99802

Phone: 789-0841

Central - Region I

Jack M. Spake
Central District Engineer
Department of Highways
5700 Tudor Road
P. O. Box 6750
Anchorage, Alaska 99502

Phone: 337-1511

Interior - Region II

H. Woodrow Johansen
Interior District Engineer
Department of Highways
2301 Peger Road
Fairbanks, Alaska 99701

Phone: 452-1911

Southcentral - Region V

Rowe D. Redick
Southcentral District Engineer
Department of Highways
P. O. Box 507
Valdez, Alaska 99686

Phone: 835-4322

Western - Region IV

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P. O. Box 1048
Nome, Alaska 99762

Phone: 443-5266

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Department of Highways Contacts List

Overweight-Oversize Permit Contacts

Central - Region I

John Bates
Department of Highways
5700 Tudor Road
Anchorage, Alaska 99502

Phone: 337-1511

Interior - Region II

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Department of Highways
2301 Peger Road
Fairbanks, Alaska 99701

Phone: 452-1911

Southeastern - Region III

Dick Hamilton
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P. O. Box 3-1000
Juneau, Alaska 99802

Phone: 789-0841

Western - Region IV

Ron Davena
Department of Highways
P. O. Box 220
Nome, Alaska 99762

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Southcentral - Region V

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P. O. Box 506
Valdez, Alaska 99686

Phone: 835-4322

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Department of Natural Resources Contact List

Southeast Land District Office

Henry Lee Hall
Division of Lands
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Phone: 465-2415

Southcentral Land District Office

Lawrence A. Dutton
Division of Lands
Department of Natural Resources
323 East Fourth Avenue
Anchorage, Alaska 99501

Phone: 279-5577

Northcentral Land District Office

William Copeland
Department of Natural Resources
State Office Building
Room 116
Fairbanks, Alaska 99701

Phone: 479-2243

Department of Natural Resources
Minerals and Energy Division

Easy Gilbreth
Minerals and Energy Division
Department of Natural Resources
323 East Fourth Avenue
Anchorage, Alaska 99501

Phone: 274-8542

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A PLAN FOR
ALASKA'S FINANCIAL PARTICIPATION
IN THE
ALASKA HIGHWAY PIPELINE PROJECT

April 17, 1978

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Appendix I

I. INTRODUCTION

The purpose of this memorandum is to describe and recommend a specific plan for participation by the State of Alaska in financing of the Alaska Highway Pipeline Project (the "Project"). The Project will encompass approximately 4,800 miles of pipeline consisting of four segments which will be separately and independently financed and constructed. These four segments, their mileage and estimated cost are:

Alaska	-	731 miles	-	$ 3.7 billion
Canada	-	2028	-	4.1
Western Leg	-	911	-	.8
Eastern Leg	-	1117	-	1.7
		4787 miles		$10.3 billion*/

It is proposed that the State participate only in the funding of the 731 mile Alaska segment.

In order to begin construction of the Project in 1980, final commitments for debt and equity must be made by early 1979.

To meet this critical schedule, we are proposing specifically that the legislature this session enact legislation creating a financing authority (the "Authority") to issue $1.0 Billion in tax-exempt revenue bonds in a manner that would not utilize the State's credit or adversely affect the State's credit rating and adopt a joint resolution establishing an interim committee to study how the state can best participate

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*/ The financing requirements of the Project were estimated in the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System ("President's Decision") to be approximately $10.3 billion in escalated dollars.

in equity financing. It is essential that the committee report back to the legislature early next session so the necessary legislation can be enacted in time to permit the State's equity participation to be incorporated in the overall financial plan.

This memorandum discusses how the tax-exempt revenue bonds would be issued and proposes a plan for State equity participation that the interim committee should study and consider.

The plan for State participation set forth in this memorandum would provide for an equity return to the State upon completion of the Project; encourage major institutional investors and commercial banks to invest in the Project, thereby aiding the development of Prudoe Bay gas; and add the tax-exempt debt market to the capital sources that will be called upon to complete this large and complex financing.

- o The proposed Authority would be empowered to issue $1.0 billion of tax-exempt revenue bonds ("Tax-Exempt Revenue Bonds") backed by the simultaneous purchase of a like amount of Project debt.

This transaction would raise approximately 25% of the Project's debt capital but would not involve the credit of the State. The Authority could in this way pass on to the Project the advantage of an expanded capital market. Additionally, this reduced interest cost would benefit the Project by reducing the transportation cost by approximately 4%.

This transaction would require an amendment to the Internal Revenue Code (the "Code") specifically exempting the

Project from the restrictions set forth in Section 103 of the Code. The Project does not now qualify as an exempt facility under Section 103 of the Code, and tax-exempt status would not be available for revenue bonds in the absence of such an amendment. Obtaining an amendment to Section 103 will require the cooperation of all interested parties, including the State and its representatives and the Administration. If such an amendment is not obtained, bonds issued by the Authority would be taxable and neither the State nor the Project would benefit since such bonds would be simply the equivalent of Project bonds.

- o The State would evaluate our proposal that it make an equity-related investment of $500 Million in Project Convertible Debt ("Convertible Debt").

These securities would be convertible after the Project becomes operational, if the Partnership is succeeded by a corporation, into $500 million of participating preferred stock. The participating preferred stock would carry a fixed dividend rate that would increase with the profits of the Project according to an agreed upon formula. If the Partnership is not succeeded by a corporation, the Convertible Debt could be exchanged after operations have begun for a preferred income limited partnership interest.

To maximize net return to the State, this investment could be funded principally by an appropriation of State funds. Alternatively, but with less financial return to the State,

this investment might be funded by the sale of Authority Taxable Revenue Bonds ("Taxable Revenue Bonds"), which would be secured by the Convertible Debt. If the State decides to fund all or part of its purchase of Convertible Debt in this manner, however, additional credit support beyond that of the investment itself would be required. (See Section IV for a discussion of different ways the State could provide additional backing for Taxable Revenue Bonds.)

As an investment vehicle, the Convertible Debt would provide current income to the State during the construction period, as well as an opportunity for the State to participate in an equity return subsequent to the initiation of Project operations.

At the appropriate time, the State's investment could be sold or distributed to its political subdivisions, native corporations and its citizens.

II. THE ALASKA SEGMENT OF THE PROJECT

A. Description

The Alaska segment will begin at Prudhoe Bay and parallel the Alyeska oil pipeline for 539 miles to Delta Junction. At Delta Junction the pipeline will diverge from Alyeska and follow the Alaska Highway and the existing Haines oil products pipeline for 192 miles to the Yukon Territory border.

The Alaska segment will be owned by the Partnership, and designed, constructed, and operated by Northwest Alaskan Pipeline Company ("Northwest Alaskan"), a subsidiary of Northwest Energy Company. The Partnership is currently comprised of subsidiaries wholly-owned of the following six natural gas companies:

- Northwest Energy Company
- Northern Natural Gas Company
- Pacific Gas and Electric Company
- Pacific Lighting Corporation
- Panhandle Eastern Pipe Line Company
- United Gas Pipe Line Company

It is anticipated that additional natural gas companies will join the Partnership in the future.

B. Financing Plan for Alaska Segment

The capital for constructing the Alaska segment will be raised on a project financing basis, through the sale of equity and debt securities by the Project. Debt service and return on equity securities will be provided solely by the cash flow generated from the Project's operations. These securities will be designed at the time of issuance to compete successfully in the public and private capital markets and, accordingly, will offer the appropriate market sales of interest or dividend in the case of participating preferred stock.

Under the proposed overall financing plan, a percentage amount over and above the final capital cost estimates will be committed to assure that sufficient funds are available to complete the Project. Upon completion, the Partnership will have contractual arrangements pursuant to a Federal Energy Regulatory Commission ("FERC") approved tariff that will provide funds adequate to pay debt service and provide an attractive return to the equity investors. (For a more detailed discussion of the Project's Financing Plan, see pages 8 to 14 of the Discussion Memorandum Regarding Financial Participation by the State of Alaska in the Alaska Highway Pipeline Project, dated March 15, 1978, attached as Appendix I.)

While the ratio between the equity and debt securities of the Project, as well as the timing of any takedowns, will be subject to various factors, including the financial requirements of the Project, the fundamental element of the financing plan

is that all funds -- equity and debt -- must be committed at the same time and remain committed throughout the construction period. However, no commitment shall be binding (including that of Alaska) until all equity and debt commitments necessary to complete the Project have been received.

The project's capital structure would consist of the following:

- Equity and Equity-Related Securities

  1. General Partnership Interests - The owners of the Partnership will contribute equity capital in a total amount of approximately $1.0 billion. Their partnership interests will earn the rate of return provided by the FERC approved tariff.

  2. Convertible Debt - It is proposed that Convertible Debt in a principal amount of $500 million be offered to the State of Alaska. This debt will bear an interest rate dictated by market conditions at the time of issuance, which today would be in the range of 10% to 12% per annum. After the completion of construction and the commencement of operations of the Project, the Convertible Debt will be convertible into an equivalent amount of a participating preferred stock of the corporate successor to the Partnership or into an equivalent limited partnership interest in the Partnership. The participating preferred stock would have a minimum

annual dividend rate of approximately 10%, and, in addition, would share in the profits of the Project on the basis of a pre-determined formula.

o Debt Securities

1. Series A First Mortgage Pipeline Bonds - Series A First Mortgage Pipeline Bonds in a principal amount of $2.0 to $3.0 billion will be offered to institutional investors and commercial banks at an annual interest rate that in today's market would be approximately 10%. These securities will have various maturities of up to twenty-five years, subject to sinking fund provisions.

2. Series B First Mortgage Pipeline Bonds - Series B First Mortgage Pipeline Bonds in a principal amount of $1.0 billion will be purchased by the Authority. The Series B First Mortgage Pipeline Bonds will have an annual interest rate which incorporates the maximum interest differential allowed by law (i.e., 1/8 of 1%) over the interest rate on the equivalent amount of Tax-Exempt Revenue Bonds sold by the Project through the Authority to fund the purchase. These Series B First Mortgage Pipeline Bonds will be subject to sinking fund provisions, and the underlying Tax-Exempt Revenue Bonds will have concurrent maturities.

III. ALASKA'S PARTICIPATION

As part of the financing plan described above, it is proposed that the Alaska legislature this session enact legislation to provide a mechanism for the issuance of $1.0 billion in Tax-Exempt Revenue Bonds, the proceeds of which would be simultaneously invested in $1.0 billion of the Project's Series B First Mortgage Pipeline Bonds and establish a committee to consider the proposal for investment in $500 million of equity-related securities of the Project. This Section III describes the proposed revenue bond financing mechanism, the advantages of Convertible Debt as an investment vehicle for Alaska and the returns Alaska might realize from this investment and a possible time schedule for Alaska's financial participation.

A. Revenue Bond Financing Mechanism

As was discussed earlier, the State should establish an Authority for the issuance of $1.0 billion of Tax-Exempt Revenue Bonds. Contingent upon and concurrent with the sale of the Tax-Exempt Revenue Bonds, the Authority would purchase $1.0 billion of Series B First Mortgage Pipeline Bonds, and would receive annually a 1/8 of 1% interest differential on the aggregate amount of Tax-Exempt Revenue Bonds issued by the Authority. This differential, amounting to $1,250,000 per year, is the highest allowed by Federal law and would be generated from the difference in interest rates between the Tax-Exempt Revenue Bonds and the Series B First Mortgage Pipeline Bonds.

B. Convertible Debt

During the period in which the Convertible Debt is outstanding, the interest received by the State, assuming the entire amount is outstanding, would be approximately $55 million. This debt would be convertible into participating preferred stock of any successor corporation to the Partnership. After conversion the State would receive a fixed dividend of approximately $55 million, which would increase according to an agreed upon formula as the profits of the Project increase.

In recommending that Alaska's equity participation take the form of a fixed income security convertible into equity upon completion of the construction period, the following two considerations are particularly important:

1. Form of Ownership - The State, as a tax-exempt entity, cannot utilize the Federal income tax benefits relating to construction (e.g., the Investment Tax Credit and interest and other deductions) which will be passed through to the general partners in the Partnership. However, these tax benefits are significant to the taxable general partners who will provide the principal source of the Project's equity capital. Thus, by allocating the tax benefits exclusively to these taxable entities, the financing of the Alaska segment will be greatly facilitated at no disadvantage to the State. In addition, by structuring the State's participation during the construction period as Convertible Debt, any

conflict between the State's role as an equity investor and its role as a regulator would be minimized.

2. Return on Investment - During construction, the return on the general partners' investment will be capitalized and subject to downward adjustments depending upon the relationship between the final construction estimate and the actual construction costs.*/ Upon completion of construction and the commencement of operations, the return on common equity will be fixed by the FERC (estimated at approximately 15%). A return will be distributed first to the holders of participating preferred equity, and second to the holders of common equity, with the amounts to be distributed to holders of common equity based upon the cash requirements of the Project. As a debtholder during construction, the State's return will be fixed and distributed currently as interest. Upon the completion of construction, the State would have the option of converting its interest into participating preferred stock or the equivalent limited partnership interest.

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*/ A variable rate of return to equity investors during the construction period has been mandated by the President's Decision and the details thereof are being formulated by the FERC.

C. Timing of Alaska's Investments

The debt and equity funds to be raised from all Project investors must be committed at the same time and remain committed during the construction period. The exact timing of any drawdown will be determined as construction progresses. The current thinking is that debt and equity funds will be drawn down, pro-rata, and invested over the projected three year construction period. Accordingly, there will be some flexibility as to when Alaska's equity-related investments would be made within the constraints of the final capital drawdown schedule.

IV. IMPLEMENTATION OF ALASKA'S PARTICIPATION

This Section recommends a plan for implementing the State's participation and discusses the pertinent financial, legal, and administrative issues on which this recommendation is predicated.

A. Establishment of the Authority

It is recommended that the State establish through legislation enacted during the current legislative session a new Authority to administer the issuance of tax-exempt revenue bonds for the Project.

The establishment of the Authority during the current legislative session would greatly facilitate the financing and completion of the Project. In doing so, the State will have taken an important first step to participate in the Project's financing. This will be not only of considerable symbolic and substantive assistance in encouraging early private sector financial participation, but it is a prerequisite for Congressional action in this session of Congress to amend Section 103 of the Code.

B. Funding the Purchase of Series B First Mortgage Pipeline Bonds

It has been recommended that the Authority fund the purchase of $1.0 billion of Series B First Mortgage Pipeline Bonds through the simultaneous sale of a like amount of Tax-

Exempt Revenue Bonds. The purchase of the Series B First Mortgage Pipeline Bonds by the Authority would be contingent upon a successful placement of the Tax-Exempt Revenue Bonds with institutional investors.

Since the Partnership is a "non-exempt person" under Section 103 of the Code, interest on Authority Bonds currently would be subject to Federal income taxes. However, the President's Decision and the importance of the Project to national energy policy strongly suggest Administration support for an amendment to Section 103. Alaska legislation authorizing the Authority to issue $1.0 billion of revenue bonds during this session is essential to any effort in Congress to amend Section 103.

It is important to point out that the issuance of Tax-Exempt Revenue Bonds would not require additional State backing. The tax-exempt status of the Bonds in and of itself would assure that the Bonds would appeal to a class of investors different from those who would purchase the Project's First Mortgage Pipeline Bonds. Moreover, the value of additional credit backing in reducing the interest rate on the Authority's Tax-Exempt Revenue Bonds would be nullified by proposed Treasury Department regulations that would limit to 1/8 of 1% the spread between the tax-exempt interest on the Authority's Revenue Bonds and interest income on the Series B First Mortgage Pipeline Bonds. Accordingly, it has been concluded that additional security for Tax-Exempt Revenue Bonds would be unnecessary and an inefficient allocation of the State's credit resources.

C. Alternatives for Funding the Purchase of Convertible Debt

The funding of the State's equity-related investment will impact the State's ability to finance other State programs. Therefore, all alternatives for investment in the Project should be carefully considered. The following outlines several alternatives.

1. From the General Fund and/or the Permanent Fund - At June 30, 1977, the General Fund Investment Account had a balance of approximately $623 million. New legislation could appropriate a specified amount of monies from the General Fund for the purchase of the Convertible Debt.

The State has projected that from 1978 through 1982 the Permanent Fund will receive approximately $632 million from various mineral lease rentals, royalties, royalty sale proceeds, Federal mineral revenue sharing payments and bonuses. New legislation could direct the Commissioner of Revenue to exercise existing statutory authority to transfer a specified amount of monies from the Permanent Fund for investment in the Convertible Debt.

The State could purchase $500 million of the Project's Convertible Debt with the monies it receives from the General Fund, the Permanent Fund or a combination thereof. Importantly, the State's commitment would not become binding until all commitments necessary to

complete the Project are received and all conditions necessary to protect the State's investment are fulfilled.

Until the State's monies are drawn down to fund its commitment to the Project, they could be invested in short term securities of the U.S. Government or its agencies. This is significant because the income from such investments could either be retained by the State or used to fund its investment in the Project. Assuming the latter, a commitment by the State to invest $500 million in the Project from 1980-1982 would not require that the full $500 million be taken from the General and Permanent Funds. If monies were escrowed by the State in early 1979 and invested at a 6-1/2% rate of return, the State could meet its $500 million commitment in 1980-1982 with an initial appropriation of approximately $442 million.

2. From the Sale of Revenue Bonds*/

(a) Taxable vs. Tax Exempt

As previously discussed, a sale by the State of tax-exempt debt to fund its purchase of Convertible Debt would be much less financially attractive than a direct investment by the State. Specifically, the U.S. Treasury Department has

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*/ The issuance of General Obligation Bonds to fund the purchase of Convertible Debt would require the approval of a majority of the voters of the State under time consuming and costly bond referendum procedures required by the Alaska Constitution. Their use therefore is not recommended.

proposed arbitrage regulations that would limit the positive "spread" between the yield on the Convertible Debt and the interest paid on tax-exempt State debt to 1/8 of 1%. The arbitrage regulations do not apply to taxable debt. Accordingly, the issuance of taxable debt would be the only practical alternative if funds on hand are not utilized.

The spread between the yield on the Convertible Debt and the interest on such taxable debt would be much less than the spread between the yield on the Convertible Debt and the yield the State is now earning on its existing investments of the General and Permanent Funds. Consequently, the net income to the State would be significantly higher if the State's purchase of the Convertible Debt were financed from State funds than if such purchase were financed from the sale of taxable State debt.

(b) Additional Credit Backing for Taxable Revenue Bonds

In the event that Alaska decides to fund all or a portion of its purchase of Convertible Debt through a sale of Taxable Revenue Bonds, the State's debt would be secured by Convertible Debt. However, to provide meaningful assistance in financing the Project, it would be necessary for

the State to back its taxable debt with additional security unrelated to the Project.

If the State elects to issue Taxable Revenue Bonds, however, the two most readily available sources of additional State backing are the Permanent Fund and the State's "moral obligation." Both would involve the State's credit resources.

(i) Permanent Fund - Legislation could direct the Commissioner of Revenue to utilize assets of the Permanent Fund to meet any deficiency in Taxable Revenue Bond debt service, whether directly from monies contained in the Permanent Fund and dedicated, or indirectly by dedicating Permanent Fund monies to a special reserve fund to be used when needed to meet any such deficiency. If the latter approach were adopted, the special reserve fund could be replenished in the same manner, that is, by legislatively authorizing the Commissioner of Revenue to use Permanent Fund monies for such purpose.

(ii) "Moral Obligation of the State - It may be advisable to combine a dedication of the Permanent Fund with a legislative resolution pledging the State's moral obligation (not its legal obligation) to allocate funds if

and when it should become necessary to meet a deficiency in Taxable Revenue Bond debt service.

Moral obligation bonds have traditionally been used to finance public purpose projects such as housing, health care and educational facilities. Approximately $10 billion of the total $250 billion tax-exempt municipal bonds currently outstanding are backed by a moral obligation pledge. The State of Alaska has $240 million of bonds outstanding, issued by the Alaska Housing Finance Corporation and the Alaska Municipal Bond Bank Authority, which are the type of bonds that may be considered to be moral obligation bonds.

APPENDIX I

III. CAPITAL REQUIREMENTS AND FINANCING

The following table summarizes, by segment, the estimated capital requirements under the System design as described in the President's Decision:

Segment	Line Miles	Total (in Billions)
Alaskan	731	$ 3.7
Canadian	2,028	4.0
Eastern Leg	1,117	1.7
Western Leg	911	.9
Total	4,787	$10.3*

It should be noted that these dollar amounts do not reflect pre-delivery of Alberta gas,** minor re-routing of the line, or design changes consistent with the U.S. - Canadian negotiations. Final cost estimates of the Project will not be available until full agreement is reached on System design, governmental requirements are defined and definitive engineering is completed.

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* 1975 dollars adjusted for assumed inflation through completion of the Project.

** If agreement is reached for the sale and transportation of excess current supplies of Alberta gas, the construction of certain southern portions of the pipeline will be accelerated, resulting in lower capital requirements for certain Southern portions of the pipeline.

The capital for the Project is to be raised on a project financing basis. That is, the Project's debt service and return on equity will be provided solely by the cash flow generated from the Project's operations. Under the proposed financing plan, first sufficient funds will be committed to assure completion of the Project. Then, upon completion, the Project's sponsors will have contractual arrangements under a Federal Energy Regulatory Commission ("FERC") approved tariff providing for sufficient funds to cover debt service and an attractive rate of return to the equity investors.

1. Completion of Construction - First, before construction begins, commitments will be obtained providing for an amount of capital large enough to assure all investors that there will be sufficient funds to complete the Project. The size of this committed pool will be determined through negotiations with lenders and investors, but will reflect evaluations of the Project's final cost estimate and the estimating procedures used to develop it. These evaluations will first identify the variables that could affect the Project's capital cost (i.e., inflation, delays, etc.). Then, using probability analyses, a percentage amount over and above the final capital estimate will be determined so as to reduce to zero (or as a practical

matter as close to zero as possible) the probability of having insufficient capital to complete the Project. It is this percentage amount that when added to the final cost estimate will constitute the total capital pool to assure completion of the Project under any and all circumstances.

2. Pipeline Operations - Second, the Project's operating entities will execute service agreements that, upon completion of the Project, will unconditionally bind purchasers of Prudhoe Bay gas to pay a FERC approved transportation tariff that reflects the final cost of the Project. The terms of the proposed tariff will provide sufficient funds to meet all debt service, and will be binding even in the unlikely event of service interruption and non-delivery of gas.

As presently envisioned, the capital for constructing the Project will be raised through the sale of equity and debt securities. These securities will be designed at the time of issuance to compete successfully in the public and private capital markets and will therefore offer the appropriate market rates of return. Under current market conditions, the debt might carry an interest rate of approximately 10%. As for the equity rate of return, in previous filings and studies with FERC, Northwest Alaskan

has assumed a 15% rate of return. A substantial portion of that return would be paid out annually as dividends to the equity investors.

While the percentage breakdown between the equity and debt as well as the timing of any takedowns will be subject to market conditions, the final composition of the investor group and other factors, the fundamental element of the financing plan is that all funds -- equity and debt -- must be firmly committed at the outset and throughout the construction period.

Although it is presently contemplated that the sponsors of each segment of the Project will be responsible for separately financing its respective capital costs, the plan outlined above requires that all financing for the Project be closely coordinated. Since Northwest Alaskan's tariff payments will not begin until all segments of the Project are completed, lenders and investors undoubtedly will require that sufficient funds (whether they are raised separately or not) be available to complete all segments. Thus, close coordination between the segments is essential.

In this regard, the probability of additional costs above the final estimate is currently perceived by lenders to be higher for the Alaskan segment and Yukon

portion of the Canadian segment than for the other sections of the pipeline. This perception relates primarily to the negative publicity of Alyeska, the adverse weather conditions and the lack of pipeline construction history in permafrost and discontinuous perma-frost regions. Accordingly, lenders will probably require higher percentage adjustments above the final estimates for these northerly sections of the Project than for the other sections. While the final capital costs and percentage adjustments cannot be determined at this time, an illustrative example of the separate capital pools lenders may require is set forth below:

Segment	Preliminary Capital Requirement Estimate (billions)	Capital Pool Size As A Percent of Capital Requirement Estimate	Capital Pool Size Estimate (billions)
Alaskan	$ 3.7	125% - 150%	$ 4.6 - $ 5.6
Canadian	4.0	120% - 140%	4.8 - 5.6
U.S. Eastern Leg*	1.7	110% - 125%	1.9 - 2.1
U.S. Western Leg*	.9	110% - 125%	1.0 - 1.1
Total	$10.3	119% - 140%	$12.3 - $14.4

As previously mentioned, capital for the Project will be raised through sales of equity and debt securities.

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* The capital requirements for these segments may not be provided for on a project financing basis.

Although natural gas transmission companies will be the principal purchasers of the equity securities and institutional lenders the principal purchasers of debt securities, the size of the Project, compared with the individual and collective financial strength of the sponsors, necessitates as broad a base of financial support as possible. Consequently, the financing plan is predicated on the basis that all beneficiaries participate in the financing. These beneficiaries would include the sponsors, the producers, the suppliers and the State of Alaska. The following is a list of the various investor classes which will be asked to commit to purchase Project securities:

U.S. Transmission Companies

Canadian Transmission Companies

U.S. Banks

Canadian Banks

U.S. Long-Term Lenders

Canadian Long-Term Lenders

Producers, Suppliers, Alberta & Others

Alaska

It should be noted that all investors will be called upon to fund their commitments to the Project as construction proceeds. Because the committed capital pool will reflect the amount necessary to complete the Project,

even in the event of adverse occurrences, it is unlikely that the entire commitment of any investor will be called upon.

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AN OIL PIPELINE EMPLOYMENT MULTIPLIER AND POST CONSTRUCTION RESIDUALS IN EMPLOYMENT

By

Lynn Pistoll

October 13, 1978

INTRODUCTION AND INTENT

An area of increasing importance to Alaska decision makers is how to assess the impact of potentially large scale construction projects in the state. Alaska traditionally has been host to many such projects and for the near future, a gas pipeline, petrochemical complex, and capital move are in the planning stages.

Alaska legislators and other decision makers should feel less anxiety when making decisions concerning future large scale construction projects now that the state economy has experienced the largest private construction project in the world. Actual employment numbers are now available for 1978, quarter one, and various econometric forecasts of future growth are coming in line with each other.

The intent of this paper is to look objectively at the pipeline and post construction periods for the purpose of developing a proxy for a reasonable Alaska employment multiplier and formula for determining a post-construction residual in employment.

ESTABLISHING AN OIL PIPELINE EMPLOYMENT MULTIPLIER

An attempt has been made to establish a high and low employment impact multiplier for the recent trans-Alaska oil pipeline project. The first part of this analysis, which results in a "lower limit" employment multiplier, assumes that the project was 100 percent exogenous to the growth of the Alaska economy. The second part of this analysis assumes the project is another event in the development of the economy. This in effect establishes an "upper limit" to the oil pipeline employment multiplier. The components used in this analysis are: actual total nonagricultural wage and salary employment which is among the most consistent data series in the state, an average of the Alaska Department of Commerce and Economic Development (ACED) and the Alaska Department of Labor (ADOL) econometric forecasts of total nonagricultural wage and salary employment to 1980, and direct pipeline employment for 1975 and 1976 adjusted for a point in month estimate.1/

1/ Direct pipeline employment includes the Alyeska Service Company and all contractors.

A "LOWER LIMIT" OIL PIPELINE EMPLOYMENT MULTIPLIER

From 1966 to 1973, the period before pipeline construction, total nonagricultural employment grew at an annual rate of 5.98 percent. Under the "lower limit" scenario we can assume that if there was no oil pipeline project, this growth rate would continue to 1980, implying that the oil project was actually an extra impetus to the already fast growing economy. Figure 1 illustrates this situation.

We can now determine the difference between the extended pre-pipeline growth rate of total nonagricultural employment and the actual-forecasted growth in this series. This could be viewed as representing the surplus in jobs as a consequence of the oil pipeline project. Furthermore, if we divide these extra jobs by total direct pipeline employment, we have what could be considered a "lower limit" oil pipeline employment multiplier.

See Table 1

The mean of the "lower limit" oil pipeline multipliers for the eight quarters in 1975 and 1976 gives us 2.21 with a standard deviation of .30.

In summary, assuming the pre-pipeline growth trend would have continued without the intervention of the trans-Alaska oil pipeline project, pipeline workers created on the average 1.21 additional jobs per worker in the economy during the project.

AN "UPPER LIMIT" OIL PIPELINE EMOLOYMENT MULTIPLIER

In this scenario we assume that the oil pipeline project is one of many events in the developing economy of Alaska. If we remove the influence of the project, the pre-pipeline growth rate of nearly six percent will slow to something less. Although this "something less" is ambiguous, given the large government component of the economy and considering the many other events which contribute to normal growth, the Alaska economy would have, at a minimum, grown along a trended pre-pipeline growth rate. Trending the pre-pipeline growth rate and extending it to 1980 has the effect of dropping growth to a slower annual rate of 3.45 percent. This by Alaska standards is very conservative. Figure 2 illustrates this situation.

Once again we can subtract the difference between the trended pre-pipeline growth rate and the actual growth in total nonagricultural employment. Dividing this series by pipeline employment we have what could be considered a high or "upper limit" oil pipeline employment multiplier.

See Table 2

The multipliers for the 8 quarters in 1975 and 1976 have a mean of 2.47 and a standard deviation of .33. This analysis, then, tells us that pipeline workers during the oil pipeline project created, at most, an additional 1.47 jobs per worker.

FIGURE 1

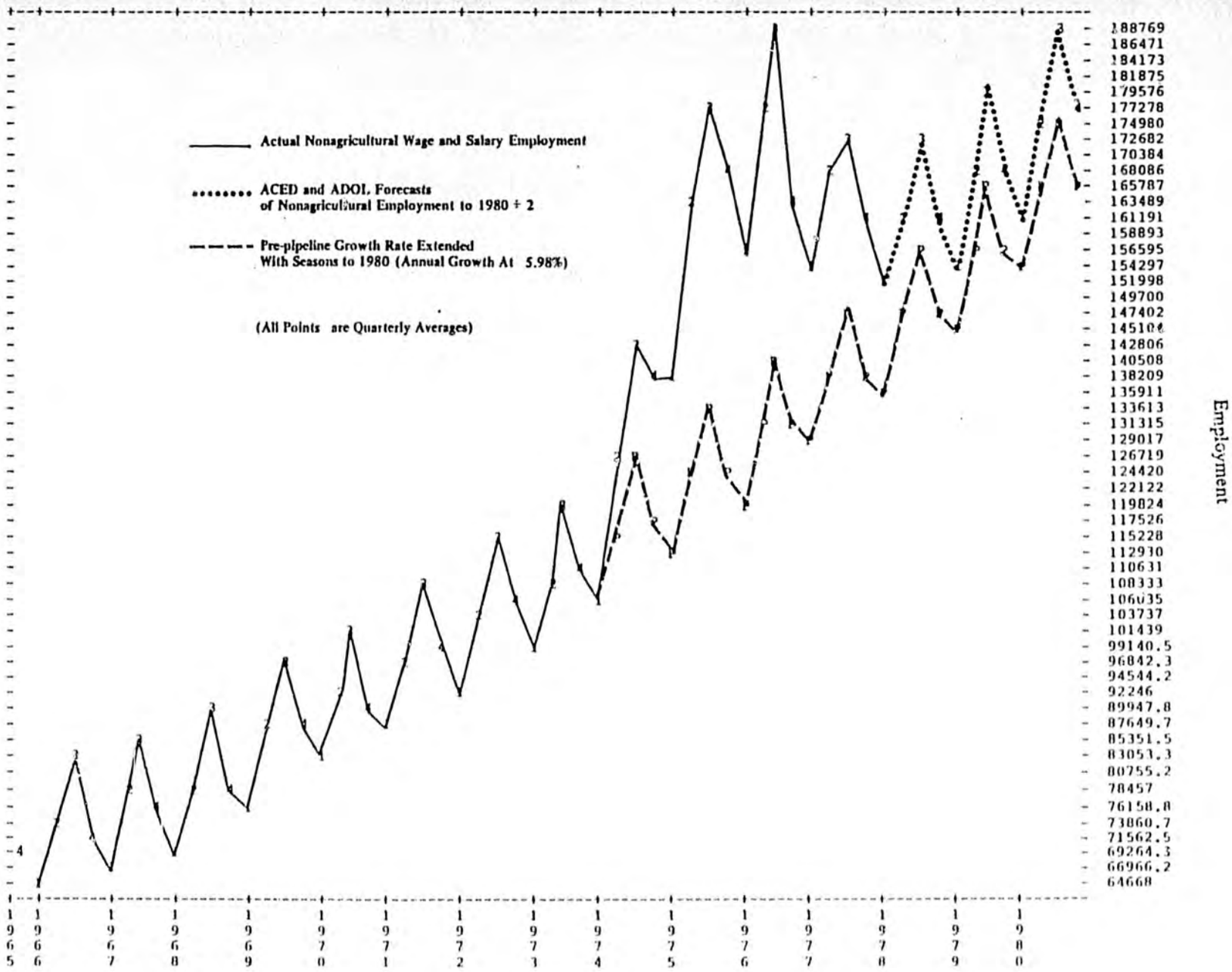
Actual Nonagricultural Wage and Salary Employment
ACED and ADOL Forecasts of Nonagricultural Employment to 1980 ÷ 2
Pre-pipeline Growth Rate Extended With Seasons to 1980 (Annual Growth At 5.98%)
(All Points are Quarterly Averages)
Employment
188769
186471
184173
181875
179576
177278
174980
172682
170384
168086
165787
163489
161191
158893
156595
154297
151998
149700
147402
145104
142806
140508
138209
135911
133613
131315
129017
126719
124420
122122
119824
117526
115228
112930
110631
108333
106035
103737
101439
99140.5
96842.3
94544.2
92246
89947.8
87649.7
85351.5
83053.3
80755.2
78457
76158.8
73860.7
71562.5
69264.3
66966.2
64668
1965
1966
1967
1968
1969
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979
1980

TABLE 1

	(1) Actual Non-Ag. Employment	(2) ACED + ADOL Forecasts of Non-Ag. ÷ 2	(3) Extended Pre-Pipeline Growth (5.98%) In Non-Ag. Employment	(4) Pipeline & Induced Employment (1) or (2) – (3)	(5) Total Direct Pipeline Employment	(6) Lower Limit On Pipeline Employment Multiplier (4) ÷ (5)
1975 1	137,238		113,325	23,913	13,282	1.80
2	162,574		123,279	39,295	17,559	2.24
3	178,019		133,354	44,665	23,316	1.92
4	168,925		123,393	45,532	16,387	2.78
(A)	161,689		123,338	38,351	17,636	2.17
1976 1	156,768		120,701	36,067	15,089	2.39
2	177,115		130,655	46,460	21,778	2.13
3	188,769		140,730	48,039	22,928	2.10
4	164,203		130,769	33,434	14,358	2.33
(A)	171,714		130,714	41,000	18,538	2.21
1977 1	155,406		128,518	26,888		
2	168,381		138,472	29,909		
3	173,478		148,547	24,931		
4	161,044		138,585	22,459		
(A)	164,577		138,530	26,047		
1978 1	153,000*		136,802	16,198		
2		161,908	146,756	15,152		
3		172,304	156,831	15,473		
4		160,906	146,870	14,036		
(A)		162,030	146,815	15,215		
1979 1		154,047	145,581	8,466		
2		167,115	155,535	11,580		
3		179,394	165,610	13,784		
4		167,893	155,649	12,244		
(A)		167,112	155,594	11,518		
1980 1		160,504	154,886	5,618		
2		174,732	164,840	9,982		
3		187,956	174,915	13,041		
4		176,683	164,954	11,729		
(A)		174,969	164,899	10,070		

* Preliminary estimate

FIGURE 2

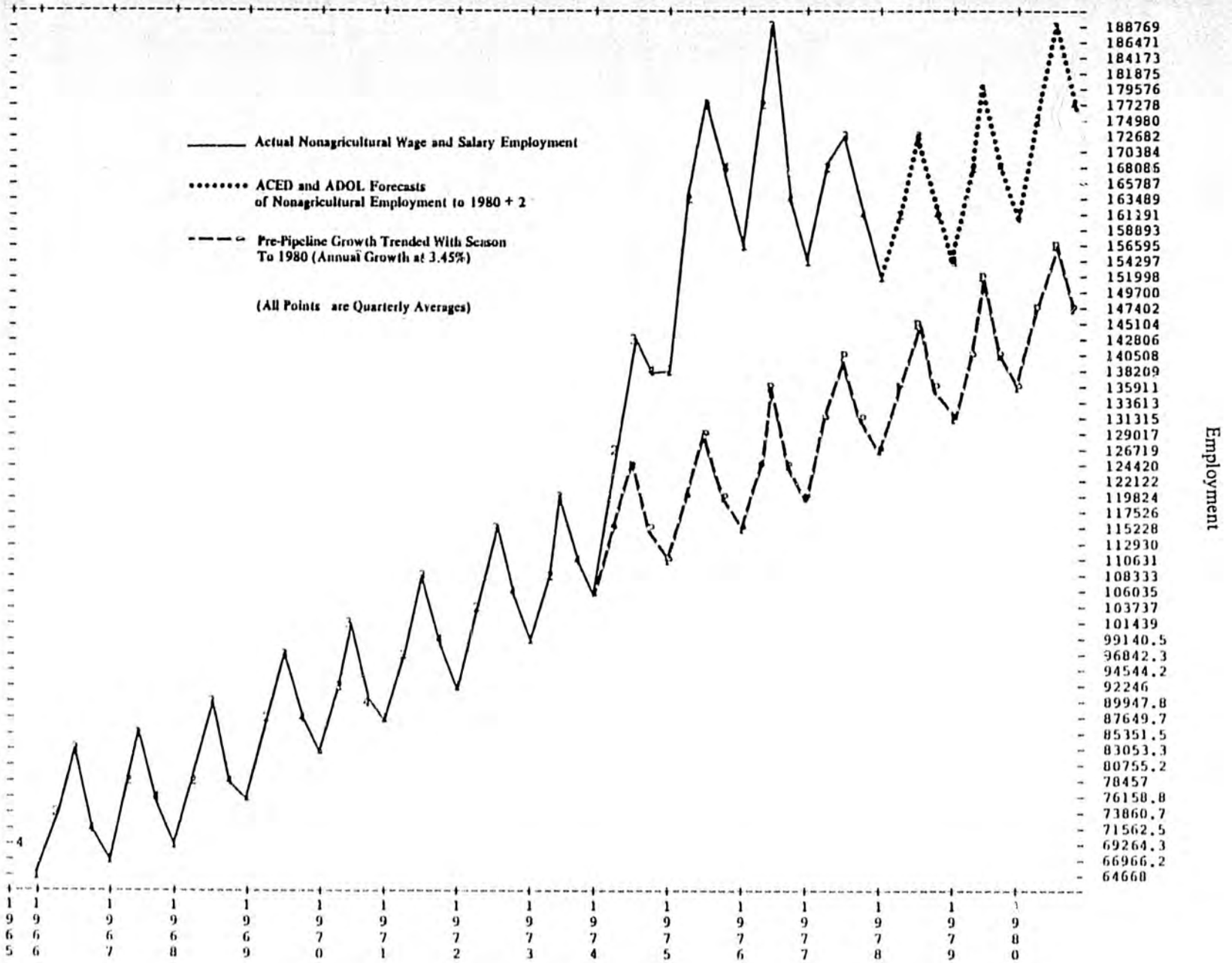
Actual Nonagricultural Wage and Salary Employment
ACED and ADOL Forecasts of Nonagricultural Employment to 1980 + 2
Pre-Pipeline Growth Trended With Season To 1980 (Annual Growth at 3.45%)
(All Points are Quarterly Averages)
Employment
188769
186471
184173
181875
179576
177278
174980
172682
170384
168086
165787
163489
161191
158893
156595
154297
151998
149700
147402
145104
142806
140508
138209
135911
133613
131315
129017
126719
124420
122122
119824
117526
115228
112930
110631
108333
106035
103737
101439
99140.5
96842.3
94544.2
92246
89947.8
87649.7
85351.5
83053.3
80755.2
78457
76158.8
73860.7
71562.5
69264.3
66966.2
64668
1965
1966
1967
1968
1969
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979
1980

TABLE 2

	(1) Actual Non-Ag. Employment	(2) ACED + ADOL Forecasts of Non-Ag. ÷ 2	(3) Trended Pre-Pipeline Growth (3.45%) in Non-Ag. Employment	(4) Pipeline and Induced Employment (1) or (2) −(3)	(5) Total Direct Pipeline Employment	(6) Upper Limit Oil Pipeline Employment Multiplier (4) ÷ (5)
1975 1	137,238		109,725	27,513	13,282	2.07
2	162,574		119,679	42,895	17,559	2.44
3	178,019		129,754	48,265	23,316	2.07
4	168,925		119,792	49,133	16,387	3.00
(A)	161,689		119,737	41,952	17,636	2.38
1976 1	156,768		115,124	41,644	15,089	2.76
2	177,115		125,078	52,037	21,778	2.39
3	188,769		135,152	53,617	22,928	2.34
4	164,203		125,191	39,012	14,358	2.72
(A)	171,714		125,136	46,578	18,538	2.51
1977 1	155,406		120,522	34,884		
2	168,381		130,476	37,905		
3	173,478		140,551	32,927		
4	161,044		130,590	30,454		
(A)	164,577		130,535	34,042		
1978 1	153,000*		125,921	27,079		
2		161,908	135,875	26,033		
3		172,304	145,950	26,354		
4		160,906	135,989	24,917		
(A)		162,030	135,934	26,096		
1979 1		154,047	131,320	22,727		
2		167,115	141,274	25,841		
3		179,394	151,349	28,045		
4		167,893	141,388	26,505		
(A)		167,112	141,333	25,779		
1980 1		160,504	136,719	23,785		
2		174,732	146,673	28,059		
3		187,956	156,748	31,208		
4		176,683	146,786	29,897		
(A)		174,969	146,731	28,238		

* Preliminary Estimate

A POST-PIPELINE RESIDUAL OF JOBS

The above discussion has focused on establishing a low and high oil pipeline employment multiplier for the two peak construction years of the project. Feeling comfortable with a construction phase multiplier ranging between 2.21 and 2.47, we can now take a look at the post-pipeline residual in jobs for our two scenarios.

Back to Table 1, the average post-pipeline (1978–1980) increase in jobs over the pre-pipeline extended growth trend is 12,268. This was computed by substracting the extended pre-pipeline growth trend (column 3) from the forecast series (column 2). We can do the same calculation for our slower growth scenario (Table 2). This produces a higher residual in jobs – 26,704.

At this point, we can say that the pipeline project has created somewhere between 12,300 and 26,700 post-pipeline jobs in the economy which otherwise would not have materialized.

AN EASY FORMULA FOR ESTIMATING POST-CONSTRUCTION EMPLOYMENT IMPACTS

Taking this analysis one step further, we have nearly all the information we need to construct a formula for estimating the employment impact of future projects with a character similar to the oil pipeline project. Two other pieces of information which will be needed are oil-pipeline operations and maintenance employment which is expected to stabilize at approximately 1800[2/] and an assumed employment multiplier for these occupations. An average of the "lower/upper limit" oil pipeline employment multipliers may be appropriate for this purpose, (2.34), although, using a higher or lower multiplier can be justified.

We can now create a low and high constant to be applied to historical peak construction employment for estimating the increase in jobs not related to post-construction operations:

Low Constant:

$$\frac{\text{post construction employment residual (low)} - (\text{operations} \times 2.34)}{\text{Peak oil pipeline employment}} = \frac{12268 - (1800 \times 2.34)}{23316} = .35$$

High Constant:

$$\frac{\text{post construction employment residual (high)} - (\text{operations} \times 2.34)}{\text{Peak oil pipeline employment}} = \frac{26704 - (1800 \times 2.34)}{23316} = .96$$

2/ Source: Alyeska

Using these constants, we can then construct a formula for estimating a post-construction employment residual range:

Low extimate of additional jobs:

(Peak employment X .35) + (operations X 2.34)

High estimate of additional jobs:

(Peak employment X .96) + (operations X 2.34)

IMPACT ANALYSIS

Using the lower and upper limit employment multiplier established for the construction phase of the oil-pipeline project and using our established formula for determining low and high post construction employment residuals, we can, for example, do a quick employment impact analysis of the proposed ALPETCO petrochemical complex and the gas pipeline project.

ALPETCO[3/]

Peak Employment = 3500
Operations = 1925

Gas Pipeline[4/]

Peak Employment = 9000
Operations = 400

Total Additional Jobs During Construction:

ALPECTO

Low Estimate
3500 X 2.21 = 7735

High Estimate
3500 X 2.47 = 8645

Gas Pipeline

Low Estimate
9000 X 2.21 = 19890

High Estimate
9000 X 2.47 = 22230

Total Additional Jobs After Construction:

ALPETCO

Low Estimate
(3500 X .35) + (1925 X 2.34)= 5729

High Estimate
(3500 X .96) + (1925 X 2.34) = 7864

Gas Pipeline

Low Estimate
(9000 X .35) + (400 X 2.34) = 4085

High Estimate
(9000 X .96) + (400 X 2.34) = 9576

3/ The ALPETCO petrochemical proposal: An Economic Analysis, by Scott Goldsmith and Lee Huskey, April, 1978.

4/ Author's estimate.

This quick analysis tells us a couple of important things. Assuming peak and operations employment estimates for the two projects are accurate, the ALPETCO petrochemical complex will have a relatively high post construction increase in employment compared to the construction phase of the project. The gas pipeline project on the other hand, will have a relatively small post construction influence on total employment when compared to the construction period.

DISCUSSION AND LIMITATIONS

As with all economic analysis there are always a myriad of variables and limitations which should be considered. The intent of this analysis was not to provide an answer for evaluating the impact of future economic events, but to provide a range of outcomes based on our valuable experience with the oil pipeline project. Hopefully, the employment multipliers and formulas for estimating construction and post construction employment residuals presented above will be used as a base for building and applying alternative assumptions as they come to light. The following areas should be given consideration:

The Changing Infrastructure

As the Alaska economy develops, the increase in goods producing and service industries will do much to reduce money leakages. This will result in an increasing employment multiplier. To keep things in perspective, however, multipliers of over 3.0 are uncommon in well developed economies such as Rhode Island, Wisconsin, and Illinois.5/

Also related to infrastructure is the project location. A project conducted in a dense, urban area of the state will undoubtedly circulate money in the local economy more times than a similar project in the bush.

Project Contingencies

It is often the case that large projects create enough political and national interest to spark other events which otherwise would have happened in due course. For example, the fast resolution of the Native Claims Settlement Act was sparked by the desire to build the trans-Alaska oil pipeline. The burgeoning of the Native Regional Corporations coupled with stepped-up oil exploration and development at Prudhoe Bay certainly added to employment during and after the oil pipeline project. These project contingencies suggest that the "upper limit" oil-pipeline multiplier developed in proceeding pages may be too high.

Local Hire and Operational Occupations

The local hire issue should be given some consideration in determining employment multipliers. Employing unemployed Alaskans rather than residents of other states will assure that a greater portion of wages circulate in the economy.

5/ David Reaume – Employment multiplier for increases in durable manufacturing jobs.

Another consideration is the occupations created by the new complex. Occupations demanding higher wage rates generally will create more jobs.

Project Size, Duration, and Intensity

The multipliers and formulas established in preceding pages are characteristic of a large specialized project crammed into a short time frame. A project of this character demands a very responsive support sector of which Alaskan industries are not totally able to supply. On the other hand, smaller projects of longer duration may give Alaskan industries ample time to adjust to new and increased demand for their services. This situation, needless to say, will result in higher employment multipliers.

SUMMARY

This paper has examined total employment fluctuations during the oil pipeline construction period for the purpose of establishing an acceptable and reasonable range for an employment multiplier. A formula has also been presented for calculating a high and low post construction residual in employment for future projects of similar character as the oil pipeline. Limitations of applying the oil pipeline experience to future projects have been discussed briefly. It is in the author's opinion that these considerations will have only slight changes on the coefficients expressed and for the near future these limitations will be well within the range specified by the "lower and upper limit" parameters.

SCOMM

#16:14

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March 16, 1978

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Honorable Bill Miles
House Special Committee
on the Sale of Royalty Oil & Gas
Pouch V
Juneau, Alaska 99811

Re: Royalty Oil Sale/ALPETCO Contract

Dear Bill:

As I mentioned, I have a few brief comments regarding the royalty oil sale which I hope will prove helpful to the Committee.

The contract generally is a major improvement over the earlier version and seems to be a serious attempt to make a conventional business deal. The critical problem, however, remains the financial viability of the proposal. I am not qualified to discuss the financial alternatives in depth and I presume most of the problems have been adequately analyzed by the state's economic consultants. I have enclosed, however, an analysis of some problems relating to oil-based petrochemicals which was done by Dr. Matthew Berman, a Rockefeller fellow associated with TfA. The terms of his fellowship preclude an advocacy approach and the enclosed discussion is an objective analysis of the issue. It should be treated as a formal submission of written testimony.

I do have some comments regarding economic viability, however. The Governor has announced that any decreases in oil price will be put to an initiative. Given an objective debate of the merits of such a subsidy, that approach may be workable. However, I foresee a strong possibility of ALPETCO paying for a massive publicity campaign (a la AOGA's tax ads) which, without adequate opposition, would almost certainly ensure approval of a subsidy.

Some serious thought needs to be given to a system of checks and balances, including not only the involvement of the administration and legislature, but also a requirement for equal media time for opponents of such a subsidy.

A rather serious problem is posed by section 2.3 of the contract. This section could allow an unlimited price subsidy at the sole discretion of the Commissioner of Natural Resources. Approval by the Royalty Board and the legislature of the mechanism outlined in that section may circumvent the established procedures for approval of sales. Since there is no requirement for fair market value, nor even a requirement that the oil be offered for sale (the language is "proposed to be offered for sale), it provides a massive loophole to future administrations which may wish to subsidize ALPETCO. Unless the Royalty Board and the legislature are involved at the "proposal to offer for sale" stage, this section may be used to avoid all input from them.

Turning to the terms of the contract itself there are several additional points which may cause some problems. The most obvious is the sale of as-yet-undiscovered oil. We have discussed this in the Energy Policy Committee and I won't belabor the point. The Committee was quite firm about not selling something we do not have and I think the arguments are still persuasive.

A second problem which was discussed in the hearings is the question of end-of-the-month billing. This delay in payments provides a subsidy to the buyer which can be substantial. Given a 9.25% interest rate (prime rate of 8% plus the 1.25% specified in the contract) and a price of $6.21 per barrel, the lost interest charges amount to approximately 3.4 million dollars per year.

I also have serious problems with the state appointing a state official to act as a coordinator for the purpose of facilitating the granting of permits. While I have not researched the legal implications of this apparent conflict of interest, it is a matter which should be looked into thoroughly by the Attorney General. It will almost certainly be an issue in any attempt to block the issuance of a state permit for the facility.

Another potential problem is the interpretation of the Force Majeure clause. The clause includes "any other event or condition otherwise not reasonably within the control of the party." A literal reading of this could include market conditions or other factors which are normally included as business risks. I don't believe that this is the intent of the state.

Some of these problems might be resolved by an appropriate colloquy between the parties. Others, however, will require amending the contract if they are to be resolved.

I appreciate this opportunity to comment on the proposed contracts.

Personal regards,

Bill

Wilson A. Rice
Executive Director

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enc

Statement Of:

Matthew D. Berman, Research Associate
Trustees for Alaska
835 D Street, Suite 202
Anchorage, Alaska 99501

To:

Special Joint Royalty Oil and Gas
Committee
Tenth Alaska State Legislature

March 16, 1978

Trustees for ALASKA

~~1020 West 4th Ave.~~, Anchorage, Alaska 99501 (907) 276-4244
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March 16, 1978

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Cambridge, Massachusetts

Honorable Bill Miles
House Special Committee
on the Sale of Royalty Oil & Gas
Pouch V
Juneau, Alaska 99811

Dear Representative Miles:

Thank you for the opportunity for me to comment on the proposed contract between the Commissioner of Natural Resources and the Alaska Petrochemical Company. As you are probably unaware of my background, I am sure it would be helpful if I supplied a few pertinent facts.

I have a Ph.D. degree in economics from Yale University and am currently on leave from the University of Texas at Austin, where I am an Assistant Professor at the Lyndon B. Johnson School of Public Affairs. I have been in Alaska since January, 1978, as a recipient of a post-doctoral fellowship from the Rockefeller Foundation's Program in Environmental Affairs to study problems with economic development and environmental preservation in the state. While carrying out my research for the fellowship, I am associated with Trustees for Alaska. However, the views expressed in this testimony are my own, and do not necessarily reflect the views of Trustees for Alaska or the Rockefeller Foundation.

Sincerely yours,

Matthew D. Berman

Matthew D. Berman

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Summary

The costs and benefits of the proposed sale of royalty oil to the Alaska Petrochemical Company (ALPETCO) cannot be determined independently of other major decisions involving Alaskan oil and gas reserves. A number of factors suggest that a petrochemical complex using crude oil as a feedstock would be non-competitive with a similar facility processing North Slope natural gas liquids. A favorable decision on the ALPETCO contract, moreover, would limit the options available for the instate use of the state's royalty gas and gas liquids.

Two sets of questions which should be resolved before a rational decision can be made on the ALPETCO contract are:

(1) How will pending national energy legislation change the method by which well-head prices are determined for crude oil and natural gas produced from North Slope fields?

(2) What will be the design and cost of the ALCAN natural gas pipeline system, and how will that project be financed?

Thus it would be unwise for the Legislature to attempt to deal with the ALPETCO contract at this time unless it is done in conjunction with an overall state plan for the disposal North Slope oil and gas resources.

There are three critical choices facing the State of Alaska regarding the disposition of state oil and gas reserves. One choice concerns the issue of state financial participation in the ALCAN natural gas pipeline. This decision may ultimately hold the key to whether or not the pipeline is ever built. A second decision that must be made arises from the alternatives for instate use of the state's royalty share of natural gas and gas liquids taken from North Slope fileds. The third decision is approval or disapproval of the ALPETCO contract for disposition of the state's royalty share of North Slope oil.

All three of these decisions hold in the balance massive development projects. Each potential project involves commitments of billions of dollars worth of scarce capital funds, as well as nonrenewable natural resources. Each has the potential to employ thousands of construction workers, bringing serious disruptive consequences for labor markets in the state, burdens on local communities that must deal with an enormous increase in demands on municipal services, and many other spillover effects from rapid immigration.

All three of these projects involve a high degree of risk. There is a substantial probability of financial failure in each case, which, in the case of the gas pipeline at least, is the reason why financial participation has been requested from the state. If successful, all three of these projects are likely to bring substantial long-term benefits to the state. There are skilled, well-paid, year-round jobs that would be created, new tax revenues

would accrue to the state treasury, and the Alaskan economy would have a more diversified economic base.

If any one of these projects is constructed and then turns out to be financially unsuccessful, the state would be left with all the negative aspects of massive construction development -- unemployment, the social problems associated with economic depression, and the environmental degradation that invariably comes from boom-bust growth. These problems will place strong demands on the state for social services at the same time as the project's failure may be draining the state's treasury. The drain on the treasury does not need to come from an unprofitable direct investment that the state may have in the project. The state and local governments would lose income and property taxes, and probably incur massive legal costs.

The current business of the Committee is to consider the merits of one of these massive development projects: The proposed sale of up to 150,000 barrels per day of royalty oil to the Alaska Petrochemical Corporation (ALPETCO) in order to obtain a commitment from the firm to construct a refinery and petrochemical complex within the state of Alaska. A favorable decision should be made if it is determined that the total benefits to the residents of the state of Alaska outweigh the total social costs, including consideration of those costs and benefits which do not translate readily into a dollar yardstick. Certainly, it appears that it is the intent of the state legislature to use this criterion as the basis for its decision.

The purpose of this testimony is not to express an opinion one way or the other on the merits of the proposed ALPETCO contract. Surely, it is hoped that the legislature will make its decision on the basis of facts, not opinions. Rather, the purpose of this testimony is to express a serious doubt that the process by which the legislature is reviewing the proposal, including its scrutiny by the Royalty Oil and Gas Development Advisory Board and the House Special Committee on the Sale of Royalty Gas & Oil, will produce except by chance, a satisfactory outcome for the state. There seems to be substantial political pressure, apparently due to the fact that 1978 is an election year for the Administration and the House of Representatives, to expedite the legislative review in order to obtain a quick decision on the ALPETCO proposal.

In all this rush, it appears that a critical factor underlying the costs and benefits of the ALPETCO project seems to have been overlooked completely. No intelligent decision can be made on the proposed royalty oil contract in isoloation from the two decisions regarding the disposal of North Slope gas. The true value of the ALPETCO project is heavily dependent on the natural gas decision. Conversely, the options available for North Slope gas may be severely limited by approval of the ALPETCO proposal. The economic issues involved here are far more complex than the simple fact that the royalty oil and gas in question are both produced from the same fields.

What do royalty gas proposals have to do with ALPETCO? On January 23, 1978, Bonner and Moore Associates, Inc., submitted their study of options for instate utilization of the state of Alaska's royalty gas to the

Department of Revenue. Under contract to the Department, this firm was asked, among other things, to identify options for instate manufacture of natural gas which might be economically feasible. The most feasible alternative studied was an ethane cracking plant producing ethylene-based olefins (see page 4-2 of the Bonner and Moore study) using royalty gas liquids as a feedstock. Although there is a narrower range of final products in this gas liquids proposal than in the ALPETCO royalty oil bid, the same basic type of product would be manufactured.

If the state is considering sale of its royalty gas for instate processing, it is important to note that the two petrochemical projects -- the ALPETCO royalty oil proposal at hand and Bonner and Moore's most feasible alternative for instate manufacture of natural gas liquids -- would inevitably have to compete against each other in a number of ways. The projects will have to compete for capital funds and construction workers, as well as for customers. Would there be financing available for a billion dollar gas liquids plant if ALPETCO has to struggle to raise over a billion dollars for a project located in the same place selling to the same potential customers? Would labor be available to build both projects without long delays, massive immigration, cost overruns, or all three? Would there be a market for all the ethylene products produced from both plants?

Because of the competition that would exist for markets, capital and labor, it is quite likely that an action to award the state's royalty oil to

ALPETCO forecloses the option for the state to find an instate processor for the gas liquids. It certainly will have a profound effect on the feasibility of the alternative uses of royalty natural gas.

Given the strong probability that only one world-scale petrochemical plant can be constructed in the state of Alaska, one should, accordingly, take a close look at the factors which are likely to affect the desirability of a gas liquids proposal relative to the ALPETCO proposal. Since the two projects are basically similar in technology, construction, operation, environmental effects, etc. the most important question regarding the relative strengths of the two proposals is the risk of financial failure. As stated above, the failure of a major construction project once built will place severe demands on the state and local governments, even if the state has no financial interest at stake in the project itself.

What are some of the primary determinants of the relative financial riskiness to the projects and to the state of Alaska?

1) The gas liquids proposal involves a simpler process to produce a smaller range of products than the ALPETCO proposal. This simplifies both operating procedures and marketing tasks. According to Bonner and Moore (Royalty Gas Study, p. 7-4), "Most likely the use of NGL as a petrochemical feedstock would be preferential to the use of crude oil at an equivalent feedstock value."

2) Royalty oil has a secure, valuable market for export using existing transportation systems, while there are currently no transportation systems

available to export royalty gas or gas liquids. This means that the possibility that the state might at some future date have to sell royalty oil to ALPETCO for less than its full market value is a more serious financial risk than a possible "gas subsidy" to a gas liquids plant, since there is no export market for North Slope gas at the present time.

3) Even if the pipeline is built and can operate profitably, the total oil revenues which the state is risking with ALPETCO are likely to be far more than royalty gas revenues, due to the relatively higher cost of transportation of Alaskan gas to the market in the lower 48 states.

4) Bonner and Moore estimated that it would cost 40% more to construct a petrochemical plant in Alaska than along the U.S. Gulf coast. This means that a substantial operating cost savings must be realized in some aspect of the manufacturing process in order that the plant may prove financially feasible. For the ALPETCO project, the Bonner and Moore revised study of royalty oil alternatives points out clearly that the Alaskan cost factor, which they estimated at $1.80 per barrel of oil, could be counteracted by the fact that ALPETCO would receive an "entitlements" credit of roughly $2.30 per barrel of oil it processes under existing federal law.

It would be extremely risky, however, to base a judgment of feasibility of the petrochemical operation on obtaining the entitlements credit since

(a) The entitlements program is in doubt under pending energy legislation,

(b) The value of the entitlements credit is very likely to fall

to zero before the ALPETCO plant becomes operational, even if the law remains in effect,

(c) The entitlements credit may only be received if the refined oil products are sold in the U.S.A. A sale of a large proportion of petrochemical output to Japan, as is the apparent intention of ALPETCO, would mean a loss of most of the entitlements credit.

On the other hand, Bonner and Moore calculated that a natural gas liquids petrochemical plant would be economically feasible at a feedstock cost not exceeding $1.24 per MBTU in 1977 prices. It is likely that this break-even price for gas liquids will not be exceeded if either (1) financing is not obtained for the ALCAN line, or (2) the ALCAN pipeline is built and exceeds the current cost estimates of $10 billion. Thus, it is quite possible, in fact, one might say that it is quite likely that one or the other problem will develop with the ALCAN gas pipeline. It seems that the probability of financial success for a petrochemical plant in Alaska is greater if that plant is designed to use North Slope natural gas liquids rather than North Slope oil as a feedstock.

The factors discussed above seem to indicate that the ALPETCO proposal is considerably more risky, and therefore inferior, to a gas liquids alternative. However, one must bear in mind that the well-head value of North Slope gas liquids, upon which the comparative feasibility calculations are based, is extremely uncertain until the following issues are resolved:

1) A National Energy Plan establishes a mechanism for setting the well-head value of old gas under new contract;

2) Financing has been achieved for the ALCAN pipeline;

3) An agreement is reached with the Canadian Government to extract gas liquids from the pipeline in Alaska;

4) The final design for the pipeline has been set, so that ALCAN tariffs can be predicted with more confidence. Needless to say, the final design of the gas pipeline, and hence its cost, depends on whether and/or where the gas liquids will be extracted from the ALCAN gas stream, which, in turn, is dependent on a decision to process gas liquids in Alaska.

So what does this mean forthe ALPETCO contract? It means that the financial success of the project, and therefore the projected costs and benefits to the state, is closely dependent on upcoming decisions with respect to the National Energy Act, the ALCAN gas pipeline and the possible use of royalty gas liquids within Alaska for petrochemical manufacture. It would be imprudent to rush through the scrutiny of the sales contract with ALPETCO in isolation from other related decisions when the risk to the state is so great. The legislature might wish to heed the advice of Bonner and Moore (Royalty Gas Study, p. 7-4):

> "If the State were to award a royalty oil contract to a group proposing to build a fuels refinery, then royalty gas use could be considered independently. If the State were to award a royalty oil contract to a group proposing to build a petrochemical refinery, then it should be understood that NGL availability at the right price would likely require that the oil project be abandoned or converted to the use of NGL if that option were within the power of the State to grant."

It is imperative for the welfare of the citizens of this state that the legislature take the time to resolve its three major oil and gas disposal questions with a common plan. The hurried, peicemeal approach is an unwise method for deciding the fate of the state's precious nonrenewable resources.

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THE RELATION OF NON-PETROLEUM REVENUES TO PERSONAL INCOME IN THE MAP MODEL SIMULATION OF ALPETCO IMPACT

By Milt Barker, Legislative Finance Division

The ISER report on the impact of the Alpetco project met with a flurry of criticism regarding one of its main conclusions--that the project would result in greater additional expenditures by the state than the increases in revenue the State would receive. While major portions of the increased revenues were exogenous inputs to the MAP model which was used for the simulations, e.g., Alpetco's estimates of corporate income tax liabilities, some of the revenue increases were derived by the model.

The model categorizes State revenues as petroleum-related, federal transfers, income from the permanent fund, and endogenous, meaning those related to general economic activity. All petroleum revenues are exogenous to the model; the latter categories are computed by the model.

In Table II.7 from the Alpetco report (appended) the ratio of endogenous revenues to personal income (RENSRAT) declines from 9.8% in fiscal year 1977 to 5.8% in FY 2000 in the base case simulation. The report states "the slight downward trend in this proportion over time is indicative of the fact that the structure of government revenues in Alaska does not respond proportionately to an increase in economic activity."

Table I (appended) displays historical figures for personal income, some major non-petroleum unrestricted revenues, and total non-petroleum unrestricted revenues excluding investment income. The latter category should approximate that of endogenous revenues used in the MAP model which appears to include special fund revenues as well as unrestricted.

Table 2 (appended) displays the revenue figures from Table I as percentages of personal income. For the period 1961 to 1978, the ratio for total revenues increased from 5.5% to 7.6%. There is a sub-period from 1965 to 1974 during which the ratio of total revenues to personal income steadily declined, but upon constuction of TAPS, the ratio jumped to a new high of 8.8% in 1977. Of course, the TAPS project being of unparalled magnitude relative to Alaska's economy may mean that that high may not be reached again.

However, examination in Table 2 of the main component of endogenous revenues, the personal income tax, reveals a more definite upward trend in its ratio to personal income. This is logical, given that individual incomes have been rising and that the personal income tax structure is progressive. Indeed, this fact of an upward trend is reflected in recent efforts to index income taxes to avoid an increasing percentage government take due to inflation.

It appears that personal income in proportion to endogenous State revenue in the base case simulation (Table II.7) in 1977, 9.8%, is correct, allowing for special funds. However, whether this ratio should decline over time as in the simulation is open for question.

There will be a one-time downtick in State endogenous revenues due to the repeal of most of the business license tax. The Department of Revenue estimates this will drop business license revenues from $21.3 million in FY 79 to $4.1 million in 1980.

Also, the upward trend in the ratio for personal income will certainly be held in check for the next few years by tax credits enacted into law in 1978. However, it should resume its climb thereafter barring indexation (not unlikely - SB 76 and HB 268 were introduced for this purpose in 1977) or further tax reduction measures. The movement of the personal income tax should be more determinate of the trend in endogenous revenue in the future since by FY 1978, it accounted for 48% of all endogenous revenue up from 28% in 1961.

Of course, what was of concern in the Alpetco report was not the way the model's assumptions worked themselves out in the base case, but their depiction of Alpetco's impact. In Table 3 (appended), the increases in personal and non-petroleum corporate income taxes generated by Alpetco are compared to increases in personal income stemming from the project. These figures are derived from Tables III.4 and III.6 in the Alpetco report (appended). Alpetco's estimated corporate income taxes are excluded from non-petroleum corporate income taxes.

From this last table, it appears that the increase in non-petroleum corporate income taxes relative to increases in personal income is at the level of recent historical averages, .7%, over most of the simulation while that for the personal income tax ranges well below the historical averages in Table 2. In the absence of legislation, the ratio for personal income taxes in Table 3 should increase over time due to the effect of a progressive tax structure on increasing incomes, both nominal and real.

However, the ratios in Table 3 are measures of the marginal responsiveness of taxes to increases in personal income and should be judged for reasonableness by looking, not at the average ratios in Table 2, but by some marginal measures that can be derived from Table 1. For example,

Fiscal Year	Change in Personal Income Tax as a % of Change in Personal Income	Change in Non-Petroleum Corporate Income Tax as a % of Change in Personal Income
1975	5.2%	1.8%
1976	6.7	.8
1977	20.2	1.3
1978	83.1	2.6

Certainly these marginal rates for the pipeline construction years are only relevant to the construction phase for Alpetco. Yet, the highest marginal rate of personal income tax to personal income increases during Alpetco construction is only 3%. Given the cavalier expenditure of funds for TAPS construction, a proper ratio for Alpetco would perhaps be less than those experienced during TAPS construction.

The model might be improved by making income taxes more responsive to inflation and changes in wage rates, as well as re-evaluating the direction and degree of a trend, if any, in the relation of endogenous revenues to personal income.

Table II.7.

INDICATORS OF STATE FISCAL POSITION
BASE CASE

	SIMP	RENSRAT	EXBITES	VIABL2
1977	246.672	0.098	0.222	0.748
1978	149.935	0.082	0.257	0.658
1979	435.177	0.078	0.257	0.636
1980	814.892	0.072	0.236	0.633
1981	824.85	0.066	0.219	0.61
1982	881.842	0.067	0.232	0.568
1983	903.154	0.072	0.263	0.539
1984	1390.42	0.07	0.255	0.549
1985	1545.1	0.068	0.247	0.551
1986	1591.33	0.067	0.246	0.545
1987	1416.	0.066	0.243	0.54
1988	1185.46	0.065	0.24	0.533
1989	948.255	0.064	0.237	0.526
1990	702.368	0.063	0.237	0.516
1991	469.357	0.062	0.234	0.509
1992	221.125	0.062	0.235	0.5
1993	-15.101	0.061	0.233	0.495
1994	-276.078	0.06	0.23	0.49
1995	-567.083	0.059	0.227	0.484
1996	-918.563	0.059	0.228	0.475
1997	-1304.77	0.058	0.227	0.47
1998	-1716.03	0.058	0.226	0.465
1999	-2158.43	0.058	0.225	0.462
2000	-2654.8	0.058	0.224	0.459

SIMP = general fund revenues minus general fund expenditures (million $)
RENSRAT = endogenous revenues as a percentage of personal income (percent)
EXBITES = state total expenditures as a percentage of personal income (percent)
VIABL2 = non-petroleum revenues (not including permanent fund earnings) as a percentage of general fund expenditures (percent)

TABLE I

NON-PETROLEUM UNRESTRICTED REVENUES
($ millions)

Fiscal Year	Personal Income (1)	Personal Income Tax (2)	Non-Petroleum Corporate Income Tax (3)	Business license Tax (2)	Selected Sales & Gross Receipts Taxes (4)	Licenses, Fees and Permits (2)	Total Non-Petroleum Unrestricted Revenue Excluding Investment Income (2,3)
1961	657	10	1	1	8	3	36
1962	651	12	2	1	11	4	42
1963	693	13	2	2	11	5	43
1964	745	14	2	2	11	4	51
1965	842	16	2	3	11	5	64
1966	886	19	4	3	13	6	62
1967	972	23	3	3	13	6	63
1968	1066	23	4	4	15	7	68
1969	1163	25	4	4	17	7	75
1970	1350	32	5	5	19	8	89
1971	1470	36	6	6	20	9	95
1972	1618	39	6	6	21	9	104
1973	1840	43	6	7	23	10	115
1974	2165	49	7	8	25	11	132
1975	2900	87	20	11	31	14	204
1976	3774	146	27	19	41	16	287
1977	4091	210	31	23	40	16	362
1978	4014*	146	29	22	44	19	305

Sources:
(1) U.S. Dept. of Commerce, Bureau of Economic Analysis (fiscal year basis)
(2) Alaska Dept. of Revenue, "Revenue Sources"
(3) Alaska Dept. of Revenue, unpublished data
(4) Includes fuel, alcoholic beverage, tobacco products, insurance premiums and electric and telephone utilities taxes

*Based on Commerce & Economic Development estimate for 4th quarter 1978

TABLE 2

NON-PETROLEUM UNRESTRICTED REVENUES AS A % OF PERSONAL INCOME

Fiscal Year	Personal Income Tax	Non-Petroleum Corporate Income Tax	Business License Tax	Selected Sales & Gross Receipts Taxes	Licenses, Fees, and Permits	Total Non-Petroleum Unrestricted Revenue Excluding Investment Income
1961	1.5%	.2%	.2%	1.2%	.5%	5.5%
1962	1.8	.3	.2	1.7	.6	6.5
1963	1.9	.3	.3	1.6	.7	6.2
1964	1.9	.3	.3	1.5	.5	6.8
1965	1.9	.2	.4	1.3	.6	7.6
1966	2.1	.5	.3	1.5	.7	7.0
1967	2.4	.3	.3	1.3	.6	6.5
1968	2.2	.4	.4	1.4	.7	6.4
1969	2.1	.3	.3	1.5	.6	6.4
1970	2.4	.4	.4	1.4	.6	6.6
1971	2.4	.4	.4	1.4	.6	6.5
1972	2.4	.4	.4	1.3	.6	6.4
1973	2.3	.3	.4	1.3	.5	6.3
1974	2.3	.3	.4	1.2	.5	6.2
1975	3.0	.7	.4	1.1	.5	7.0
1976	3.9	.7	.5	1.1	.4	7.6
1977	5.1	.8	.6	1.0	.4	8.8
1978	3.6	.7	.5	1.1	.5	7.6

TABLE 3

ALPETCO IMPACT
RESPONSIVENESS OF INCOME TAXES TO INCREASES IN PERSONAL INCOME

Fiscal Year	Increase in Personal Income Tax as a % of Increase in Personal Income	Increase in Non-Petroleum Corporate Income Tax as a % of Increase in Personal Income
1979	1.1%	-
1980	1.4	.1%
1981	1.4	.2
1982	1.9	.4
1983	2.1	.5
1984	3.0	.7 (or 1.0%)*
1985	2.5	.8
1986	2.2	.7
1987	2.0	.6
1988	2.0	.6
1989	2.0	.6
1990	1.8	.6
1991	1.8	.6
1992	1.6	.6
1993	1.7	.6
1994	1.7	.6
1995	1.8	.6
1996	2.0	.8
1997	1.9	.7
1998	1.9	.7
1999	1.8	.7
2000	1.8	.7

*Depends on whether a negative tax liability for Alpetco for this year as shown in the simulation is deducted from state tax receipts.

Table III.4.

IMPACT OF ALPETCO ON INCOME AND PRICES

	PI	PINRPC	RPI	PRAT
1977	0.	0.	0.	0.
1978	0.	0.	0.	0.
1979	71.844	39.084	0.538	0.003
1980	247.141	110.383	1.834	0.009
1981	757.109	272.281	5.013	0.022
1982	1020.05	290.375	6.691	0.028
1983	1167.77	308.207	7.823	0.032
1984	697.16	83.859	5.796	0.022
1985	512.164	19.605	4.205	0.015
1986	448.848	-7.918	3.594	0.013
1987	440.695	-20.168	3.404	0.011
1988	456.371	-26.223	3.38	0.011
1989	486.73	-29.762	3.428	0.01
1990	522.66	-31.324	3.51	0.01
1991	566.383	-32.109	3.616	0.01
1992	612.32	-31.937	3.734	0.01
1993	666.082	-31.652	3.966	0.01
1994	726.457	-31.758	3.998	0.009
1995	799.941	-31.805	4.143	0.009
1996	739.168	-45.789	3.66	0.008
1997	737.668	-51.824	3.509	0.007
1998	762.18	-53.855	3.476	0.007
1999	803.055	-54.277	3.499	0.006
2000	830.598	-55.316	3.453	0.006

PI = personal income (million $)
PINRPC = real per capita personal income (deflated by RPI)
RPI = relative price index for Alaska (1967US = 100)
PRAT = ratio of RPI to U.S. CPI

Note: All variables measured as the difference from the base case.

Table III.6.

IMPACT OF ALPETCO ON INDIVIDUAL COMPONENTS
OF STATE ENDOGENOUS REVENUES

	RENS	RT98	RTCSX	RTCTS	RTBSX	RTBS	RTIS
1977	0.	0.	0.	0.	0.	0.	0.
1978	0.	0.	0.	0.	0.	0.	0.
1979	0.961	0.961	0.	0.	0.	0.006	0.769
1980	7.904	6.936	0.4	0.757	1.4	1.697	3.549
1981	22.307	18.945	0.6	1.894	2.3	3.339	10.927
1982	45.899	35.537	0.5	4.641	2.4	5.619	19.802
1983	58.785	44.643	0.5	6.362	2.6	7.015	24.33
1984	58.116	41.681	-2.	4.826	3.9	8.785	21.317
1985	39.724	30.044	0.	4.039	5.8	8.41	13.31
1986	55.935	48.855	24.	26.929	6.5	8.345	10.244
1987	69.812	63.617	40.4	42.965	6.8	8.379	9.258
1988	76.745	70.648	47.2	49.754	7.2	8.743	9.177
1989	83.509	77.164	52.7	55.391	7.6	9.195	9.529
1990	90.456	83.648	57.8	60.745	7.9	9.618	10.09
1991	98.101	90.737	63.2	66.435	8.3	10.154	10.782
1992	106.314	98.275	68.8	72.404	8.7	10.732	11.563
1993	115.378	106.62	75.	78.984	9.2	11.406	12.436
1994	123.253	113.651	79.7	84.151	9.6	12.025	13.42
1995	134.21	123.649	87.	91.979	10.1	12.769	14.557
1996	144.523	132.796	94.4	100.062	10.6	13.589	14.623
1997	150.057	139.266	102.3	107.511	11.1	13.777	13.75
1998	159.44	148.66	111.	116.31	11.7	14.378	13.753
1999	170.755	159.564	120.4	125.989	12.3	15.062	14.197
2000	182.79	170.923	129.9	135.935	12.9	15.828	14.682

RENS = total endogenous revenues (million $)
RT98 = taxes net of petroleum production (million $)
RTCSX = Alpetco corporate income taxes (million $)
RTCTS = total corporate income taxes (million $)
RTBSX = Alpetco business license taxes (million $)
RTBS = total business license taxes (million $)
RTIS = personal income taxes (million $)

Note: All variables measured as the difference from the base case.

Alaska Economic Multiplier Experiments With the MAP Model

PREFACE

The attached memorandum illustrates how the basic income multiplier in the MAP models can vary over a range from about 1.5 to 2 depending on a variety of factors including the type of change being introduced into the economy, the sector in which the change originates, and the state of the economy at the time the change is introduced. These numbers fall within the range of income multiplier figures generally developed for regional economies.[1]

It may be useful to supplement the memorandum with two additional clarifying points. These are, first, a taxonomy of different types of multipliers commonly referred to by economists and economic modelers and, second, a very brief description of the difference between short run and long run in regional economic analysis.

1. Precise definitions of multipliers exist in the econometric literature, but the terminology is not entirely consistent. Goldberger has suggested the most widely recognized terms.[2] If dY_t is change in total income at t and dG_t is the exogenous change at t, then at least four multiplier concepts can be distinguished if the change in the exogenous variable is sustained for one period only.

$\frac{dY_t}{dG_t}$ impact multiplier

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[1] For example, Gary Klockenteger, "Impact Model of Sub-Regional Alaskan Employment," Economic Analysis, Vol. 1, #10, 5/26/72.

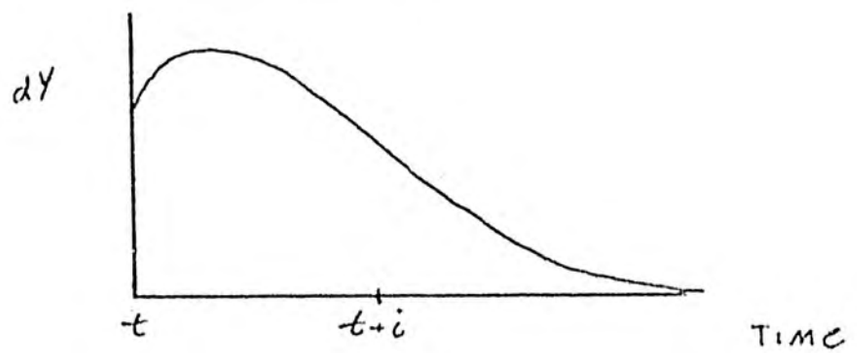
[2] See Glickman, Econometric Analysis of Regional Systems; Pindyck and Rubinfeld, Econometric Models and Economic Forecasts; and Theil, Principles of Econometrics.

$\frac{dY_{t+i}}{dG_t}$ dynamic multiplier

$\sum_{j=t}^{k} \frac{dY_j}{dG_t}$ interim multiplier

$\sum_{j=t}^{\infty} \frac{dY_j}{dG_t}$ total long-run multiplier

Generally, a response in Y over time to an exogenous change not sustained would look as shown below:



The impact and dynamic multipliers are measures of dY at a point in time. The interim and long-run total multipliers are summations of dY_t over different time periods beginning when the exogenous change was introduced.

In many applications, the exogenous change is sustained for all succeeding periods. Such a permanent change could be defined in the same framework as the multipliers above, but in fact terms for such changes are not generally indicated in the literature. If dG_{st} is designated as an exogenous change which is sustained, then the following results are obvious:

$$\frac{dY_t}{dG_t} = \frac{dY_t}{dG_{st}}$$

$$\frac{dY_{t+i}}{dG_t} < \frac{dY_{t+i}}{dG_{st}}$$

$$\sum_{j=t}^{\infty} \frac{dY_j}{dG_t} < \sum_{j=t}^{\infty} \frac{dY_j}{dG_{st}} = \infty$$

2. In a short-run analysis of impact on a regional economy, the following assumptions are generally made or are implicit:

a. resources of the region are fixed (labor, capital, materials)
b. prices and wages constant
c. government spending, exports, and investment exogenous
d. consumption and imports a function of income

The basic equation for income determination in the region is

$$Y = C + I + G + (X-M) \tag{1}$$

and the short-run multiplier for a change in any exogenous factor (I, G, or X) is

$$\frac{dY}{dI} = \frac{1}{1-s} \tag{2}$$

where s is the marginal propensity to consume locally.

This relationship holds only if there is excess capacity, because if a positive exogenous change occurs at full capacity utilization, then prices must rise, resources must increase through in-migration, or both. These responses are not allowed by the model assumptions.[3]

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[3]Taken from Hugh Nourse, Regional Economics, chapter 7.

In a long-run analysis, none of the assumptions made for the short run would hold. Specifically, one would expect in the case of an expanding economy that,

a. Resources of the region would increase because of technological change as well as factor movements and growth.

b. Prices would respond to supply and demand conditions.

c. Investments and government spending would be a positive function of regional income just as consumption is in the short run.

d. Imports would be a declining proportion of income over time because of import substitution.

Relaxing these assumptions has a significant effect on calculation of $\frac{dY}{dI}$. The model is now as follows:

$$Y = C + I + G + (X-M) \tag{3}$$

$$C_\ell = C + cY$$
$$G_\ell = G + gY$$
$$I_\ell = I + iY$$
$$M_\ell = m_\ell Y$$
$$X_\ell = \bar{X}$$

and the long-run change in income in response to exogenous change would be as follows:

$$\frac{dY_\ell}{dX_\ell} = \frac{1}{(1-c-i-g+m_\ell)} \tag{4}$$

where c, i, g are the marginal propensities to consume, invest, and increase government expenditures out of income, and m_ℓ is the relationship between

changes in income and changes in imports. In the short run, i=g=o and m_s substitutes for m_ℓ.

$$\frac{dY}{dX} = \frac{1}{(1-c+m_s)} \tag{5}$$

The difference in the effects calculated using (4) or (5) can be seen with a simple example. Let

$$c = .7$$
$$g = .2$$
$$i = .07$$
$$m_s = .3$$
$$m_\ell = .25$$

Then $$\frac{dY_s}{dX} = 1.67$$

$$\frac{dY_\ell}{dX_\ell} = 3.57$$

Scott Goldsmith
University of Alaska

MEMORANDUM

FROM: David Kresge

DATE: April 10, 1978

SUBJECT: Economic Impacts and Multipliers in the MAP Model

SUMMARY

- The value of the basic income multiplier in the MAP models is approximately 1.6.
- The income multiplier in the MAP models varies (typically over a range from about 1.5 to 2.0) depending on the type of change being made, the sector in which it originates, the state of the economy. the time the change is made, and a variety of other factors.
- When there are simultaneous changes in several policy variables or outside forces, the overall impact can be much larger (or smaller) than indicated by the simple multipler.
- Ratios of total change to initial change in employment or income provide useful summary measures of economic impacts. There are few instances in which these ratios could be used to derive multipliers that would produce valid predictions of policy impacts.

MULTIPLIER EXPERIMENTS

The MAP models are designed to provide a reasonably detailed and yet comprehensive picture of the Alaska economy. One of the principal functions of the MAP models is to provide estimates of the impacts caused by changes in outside factors and to determine the effectiveness of alternative state economic policies. As a summary measure of the impacts of changes in exogenous factors or policy instruments it is often useful to calculate a so-called "income multiplier", which is defined as the change in total real income in the economy divided by the change in real income in the sector where the impact originates. The effective income multiplier due to an increase in petroleum sector employment, for example, would be calculated as the change in Alaska real personal income divided by the change in real wages in the petroleum industry. The term "real" indicates that the income changes have been adjusted to take into account any induced changes in the cost of living in Alaska.

Several experiments have been run to provide estimates of the income multipliers in the MAP models. In the first experiment, which is reported in the first line of Table 1, federal government employment in Alaska in increased by one thousand persons. This causes an increase in total employment of 1,450 and raises real disposable personal income by a little over $10 million (in constant 1967 prices). The increased pace of economic activity pushes up wage rates by 0.3%, a change which is very nearly matched by the increase in the cost of living. As shown in the last column of the table, the implied income multiplier is 1.6. This figure is probably the single best estimate of the "basic" income multiplier in the MAP model. It is also most comparable to the multiplier discussed in economics textbooks and the multiplier reported for other economic models.

The second experiment reported in Table 1 considers an increase of one thousand in petroleum sector employment. Since the petroleum sector pays very high wages, this would, of course, be expected to have a larger impact on the economy than the equivalent increase in federal government employment. In addition to producing a larger initial increase in real earnings, this experiment causes the income multiplier to rise to 2.1. When petroleum sector employment expands in Alaska, this tends to push up both wage rates and the cost of living, but the wage rates tend to increase faster than the cost of living. This increase in real wage rates adds an element to the multiplier process that was not present in the case of an increase of federal government employment. Thus, in comparing the impacts of equivalent changes in employment, a change which originates in the petroleum sector causes total Alaska employment to rise by 2,550 rather than 1,450, and increases real income by $32 million rather than $10 million.

Table 1 also reports, as a second summary impact measure, the ratio of the total change in employment to the change in employment in the initiating sector. This ratio is 1.4 when federal government employment increases, and 2.6 when petroleum employment increases. Most of the difference between the two experiments is due to the fact that wages are so much higher in the petroleum sector, but it also reflects the increase in the income multiplier caused by the boom-induced increase in real wage rates associated with petroleum sector expansion.

The experiments reported in Table 1 assume that the state's fiscal policies are not adjusted in response to changes in economic activity in Alaska. This is the standard approach used in multiplier analysis and there is a very good reason

TABLE 1

MAP MODEL ESTIMATES OF 1980 IMPACT MULTIPLIERS:
RESPONSE TO EMPLOYMENT CHANGES (WITH NO FISCAL RESPONSE)

EXPERIMENT	Changes from base case				Percent change from base case		SUMMARY IMPACT MEASURES	
	Initial change in employment (thousands)	Total change in employment (thousands)	Initial change in real wage earnings (millions of 1967 $)	Total change in real disposable personal income (millions of 1967 $)	Average wage rates	Alaska cost of living	Ratio of total to initial employment change	Real income multiplier
Increase of 1000 in federal government employment	1.00	1.45	6.33	10.11	0.3	0.3	1.4	1.6
Increase of 1000 in petroleum sector employment	1.00	2.55	15.12	32.26	1.4	0.5	2.6	2.1

for it. If fiscal policy were allowed to change, then the resulting impacts would confound the effects of a change in an exogenous factor with a change in a policy variable. While the MAP models have no difficulty in dealing with such simultaneous changes, the usefulness of the multiplier concept tends to break down when more than one factor is changed at the same time. The effects of such simultaneous changes, as estimated by the MAP models, will be discussed later but first it is useful to consider the impacts of changes in fiscal policy when other factors are held constant.

The first experiment in Table 2 considers the impact of an increase of $10 million in state government wages and salaries. In real terms, this amounts to an increase of a little over $3 million (in 1967 prices) and produces an increase in real personal income of $5.6 million. The implied income multiplier is 1.8. In the second experiment, state government expenditures are increased by $20 million but less than half of this money goes into wages and salaries while much of it goes to purchase commodities from outside the state. Therefore, the aggregate economic impact is less than in the previous experiment. Nonetheless, the income multiplier is about the same as before, in fact, slightly higher if it is calculated as the change in real income divided by the change in real wages paid to state employees. On the other hand, the multiplier is only 0.7 if it is calculated as the change in real personal income divided by the change in real state spending.

The final experiments, as reported in Table 3, consider the effects of exogenous employment increases which are accompanied by fiscal policies which increase state expenditures in response to the expansion in economic activity and population. The fiscal response in the experiments is, however quite modest and the increase in real state spending does not nearly keep pace with the increase in population. For example, in the experiment where petroleum sector employment is increased by a thousand, total employment goes up by 1.4%, personal income increases by nearly 3% (in current prices), but state expenditures increase by only 0.7%.

When fiscal policy is allowed to respond to changing economic conditions, the effects of exogenous changes in employment levels are, as would be expected, larger than when fiscal policy was held fixed. Thus, the summary impact measures shown in Table 3, are larger than the comparable measures in Table 1. It should be noted that the entry in the last column of Table 3 is no longer called a real income multiplier.

TABLE 2

MAP MODEL ESTIMATES OF 1980 IMPACT MULTIPLIERS:
RESPONSE TO CHANGES IN FISCAL POLICY

EXPERIMENT	Changes from base case				Percent change from base case		SUMMARY IMPACT MEASURES	
	Initial change in employment (thousands)	Total change in employment (thousands)	Initial change in real wage earnings (millions of 1967 $)	Total change in real disposable personal income (millions of 1967 $)	Average wage rates	Alaska cost of living	Ratio of total to initial employment change	Real income multiplier
Increase of $10 million in state government wages and salaries	0.33	0.64	3.03	5.57	0.2	0.1	2.0	1.8
Increase of $20 million in state government expenditures	0.24	0.48	2.22	4.27	0.2	0.1	2.0	1.9 (0.7)

TABLE 3

MAP MODEL ESTIMATES OF 1980 IMPACTS OF EMPLOYMENT CHANGES WHEN ACCOMPANIED BY MODEST RESPONSE IN STATE EXPENDITURES

EXPERIMENT	Changes from base case				Percent change from base case		SUMMARY IMPACT MEASURES	
	Initial change in employment (thousands)	Total change in employment (thousands)	Initial change in real wage earnings (millions of 1967 $)	Total change in real disposable personal income (millions of 1967 $)	Average wage rates	Alaska cost of living	Ratio of total to initial employment change	Ratio of total to initial change in real income
Increase of 1000 in federal government employment	1.00	1.67	6.37	12.17	0.4	0.4	1.7	1.9
Increase of 1000 in petroleum sector employment	1.00	2.98	15.12	35.93	1.6	0.6	3.0	2.4

Although the ratio of total to initial change in real income in this experiment still provides a useful summary measure of economic impact, it differs so significantly from the usual multiplier concept that it would be grossly misleading to refer to it as a "multiplier". Unlike the usual multiplier, which is typically assumed to remain fairly constant, the ratios shown in the last two columns of Table 3 can be changed drastically by altering the state's fiscal response pattern. For example, the total employment change can be two, three, five, or even ten times as large as the initial employment change if state fiscal policy is made sufficiently responsive to changes in state population.

A final point that needs to be made concerns the use of multipliers for predictive purposes. If the multiplier can be treated as a constant, then it is possible to calculate the total impact of a policy change simply from knowing the value of the multiplier and the size of the initial employment or income effect. The problem with applying this approach to Alaska is that is is difficult, if not impossible, to justify the assumption of a constant multiplier. To use the multiplier for predictive purposes, the following conditions, among others, would have to be satisfied:

- The multiplier would have to remain constant over time.

- The multiplier would have to be the same for all types of policy changes or combinations of policies. It would also have to be the same for all changes in outside forces.

- The multiplier would have to be the same regardless of whether the initial impact is located in the petroleum sector, state government, federal government, or any other sector of the economy.

- The multiplier could not depend on the state of the economy at the time when the policy change is implemented.

It seems clear that the Alaska economy satisfies few, if any, of the above requirements. The results of the experiments reported here confirm empirically and statistically that the Alaska multipliers vary substantially, depending on the types of changes being made and the context in which they are implemented. Other work wit the MAP models shows that many policies produce impacts which tend to accumulate over time so that the

"multiplier" increases as these effects build up. Thus, it is particularly inappropriate to use the multiplier approach to analyze the impact of a policy specifically designed to alter the growth path of the Alaska economy.

October 20, 1978

THE EVALUATION OF ECONOMETRIC MODELS AND MODEL CHANGES

Scott Goldsmith

This paper reviews and discusses the generally accepted criteria for the evaluation of econometric models and shows how one might use them in the context of a potential model change.

I. The Starting Point: Initial Model Design

The starting point for every model to be used in economic analysis is economic theory. The theory tells the researcher what the general form of the relationships between the various economic variables should be. Without a specific theory, the researcher does not know what his data equations, and model are telling him.

Consider the following equation:

$$Q = f(P,X)$$

where Q = quantity of a good
P = price of that good
X = a list of other related variables

Is this a demand equation or a supply equation? It could be either in this form. A theory is necessary to choose the list of variables, X, to determine whether it is a supply or demand equation.

For the policy analysis purposes for which most econometric models are designed, a complex model is often preferred to a simpler but naive model. This complexity allows the model to be used to do a great variety of analyses. However, as soon as the researcher starts to make his model complex, he begins to encounter problems which require that he balance off different objectives. Most of this paper will discuss these tradeoffs, but a simple example will indicate the principle involved.

Consider two models: one, the DRI model of the U.S. economy or some equivalently large and complex econometric model and, the other, the following "simple" model.

$$GNP = a + bt + cT$$

where GNP = U.S. gross national product
t = time
T = income tax rate

Which model is preferred? Both are designed to calculate U.S. GNP and can accomplish policy analysis in which the effect on GNP of changing the income tax rate is determined. To make the question interesting, assume that the simple model predicts GNP better than the complex model over some period of time. This could actually be the case.

The complex model allows the researcher to analyze a large variety of tax changes and to look at the impact of the tax change on a large number of variables not present in the simple model. In addition, the complex model is based on economic theory rather than making GNP a function of time, which may improve its capability of projecting changes in the relationship of GNP to time. The choice then is between accuracy in one task on the one hand, and flexibility in use on the other. The answer depends on expected uses of the model which determines which criteria is more important, as well as the researcher's budget.

II. Data

After having developed a framework for the model based upon economic theory and the use to which it will be put, the researcher attempts to collect the data necessary to develop the parameters which define the model relationships. At this point, many models fail because data in

the real world never conforms to the expectations of the theoretical economist. Unlike the physical sciences where the researcher creates his own data through experimentation, the economist must generally rely on data collected by someone else for some other purpose. For this, however, he considers himself lucky, because for many of the variables in his theoretical model, there is no data at all.

Just because data is available on a variable is no guarantee that it is usable. In Alaska, in particular, all data should be presumed guilty of substantial "noise" (variation of reported values from the true values) until proved otherwise. The difficult problem is to determine under what conditions data with noise in it should be used anyway, and under what conditions the variable should be omitted from the analysis altogether because, on balance, it will increase the noise of the whole model. There are few easy choices in econometric model building.

Occasionally, one can clean up a data series or artificially create a data series using partial data like census information. This is a valuable technique for allowing more complex models to be built, but the same caveat about noise and noise creation is applicable here.

III. Criteria for Model Evaluation

III.A. Statistical tests

A standard set of statistical tests is available to determine, in a statistical sense, whether an individual equation in a model should be judged to be reasonable. R^2 increases as the variation of the dependent variable is better "explained" by the independent variables. The t value of individual coefficients is larger if that particular variable significantly "explains" any of the variation of the dependent variable. The list goes on. Other things being equal, high R^2 and t values are preferred. Unfortunately, these tests cannot tell the

researcher whether or not the structure of the equation corresponds to theory, however, or that it will predict and otherwise perform well. It just tells one how the equation "fits" the data. "Explain" used above really means "fit," and it should be noted that time series data, the kind more often used by economists, generally "fits" well.

If several equations in a model have been estimated simultaneously using a more exotic technique such as two-stage least squares, the same tests generally apply and the same degree of confidence should be engendered in the researcher by good statistical test results or good "fit."

Even confining the choice of equation to statistical criteria does not obviate the need for the researcher to use his judgment. One form of the equation may yield a high R^2 while the alternative, very significant t statistics. The choice will partially depend on the use of the equation. For forecasting purposes, R^2 is important; while for hypothesis testing or measurement of elasticities, large t statistics are preferable.

III.b. Formal simulation tests

For a single equation model, one can calculate the R^2, t, and the error of forecast as indications of the goodness of fit of an equation and its ability to recreate, through historical simulation, the actual historic values. A historical simulation involves running the simulation model over the historic period to see how well it "tracks" the variables it is predicting.

With a multiequation model, the situation is different if there is any interaction among the variables (and it would be a dull model if there were none), because in such a case, the statistics of all the individual equations may indicate a good "fit" and yet upon running a simulation, the model could get way "off track." This is because the interactions of the model mean that the simulation value for a particular variable now could be determined by several equations interacting simultaneously.

Table 1. MAPE COMPARISON

	MAP 65-76	Phil I	Phil III	Phil IV	Northeast Corridor	Buffalo	Los Angeles	Mississippi
gross output	.78	4.32	.97	.98	2.05	1.87	2.08	.94
total employment	1.96	1.56	1.21	.66	1.40	3.39	.88	.41
personal income	3.72	6.69	1.50	1.55	3.13	8.42	1.45	.70
population	3.15	1.02	1.49	1.27	.78	2.50	NA	NA

Source: Norman Glickman, "Son of 'The Specification of Regional Econometric Models'." Papers of the Regional Science Association, Volume 32, p. 165.

In such cases, high R^2 values are of little comfort. Several measures have been developed to measure how well a model of many variables is able to replicate the historic period by taking various aggregations of the individual differences between actual and estimated variable values. Among these measures is the mean absolute percent error or MAPE. This measure calculates for each variable the mean of the absolute percent differences between the actual and predicted values. One can thus evaluate the MAPE for a single variable (as opposed to equation) or for all variables together.

Unfortunately, there is no specific guideline to tell the researcher when a satisfactory MAPE value has been obtained either for a single variable or for the complete model. One can only compare MAPE values between model runs and between models. MAPE values for important variables of the MAP model are shown in Table 1 and can be put in perspective by comparing them to other representative regional econometric models.

The difficulty with a complex model, because of equation interactions, is that the variables are not independent of one another. Thus, the attempt to improve the MAPE statistic for one variable through a model change will normally change the MAPE statistics for several other variables. One must be resigned to the fact that it is not possible to simultaneously improve (reduce) all MAPE statistics, so the final form of the model chosen should be the one that "tracks" for the most important variables.

If the MAPE statistics are generally bad, it means that the model is not simulating well; and in order to improve on its simulating capabilities, it will probably be necessary to sacrifice some of the equations with good statistics ("fit" well according to R^2, etc.) in favor of equations that have less desirable R^2 but which nonetheless improve the ability of the model to simulate. It is the rare model builder who has not been forced into this tradeoff and, other things being equal, it is the more

simple-minded model in terms of structural interrelationships which will have the better MAPE statistics.

III.c. Theoretical reasonableness

A model may consist of equations which all have desirable statistical properties and yield low MAPE values for all variables when run over the historic period. In spite of this, it may yield "unreasonable" results when employed to do a future projection. The test of reasonableness is not quantifiable but rests upon the economic theory which was the starting point for model construction.

For example, if a regional econometric model is constructed on the basis of a neoclassical theory of factor movements, it is to be expected that over time the factor returns in the region would move toward national averages. Thus, if the model simulated wage rates growing away from parity with national averages, this would be a signal to the researcher that the model was not operating consistently with the theory, and adjustments should be made.

Alternatively, simulation results may not be what one expects, or "counterintuitive," in spite of seeming consistency with the theory. Such a result, of course, requires close investigation of the equations determining the result. If intuition is to be the final arbiter, then, of course, there is no reason to build a model at all. It is a strength of a complex model that it is able to keep track of relationships which an individual, relying on intuition and a limited memory bank, could easily overlook or lose track of.

Several types of tests of model theoretical reasonableness are common. The model should be able to pick up turning points in the time path of an important variable or significant changes in the growth rate. For the Alaskan economy, the Alyeska years would be such a case. The model should give dynamic responses to large changes in exogenous

variables and policy stimuli that are consistent with theory and recent experience. Ratios between important model variables will be (theoretically) constrained to remain within particular ranges. Monitoring these ratios is an additional check on reasonableness. For example, the ratio of employment to population could not be reasonably expected to approach zero or one.

III.d. Sensitivity tests

A well-designed model should be insensitive to a variety of changes. These include the time period during which a simulation is initiated, small changes in the values of individual coefficients, and small changes in the time paths of exogenous variables. As with theoretical reasonableness, there are no established standards of sensitivity by which the researcher can judge his results.

III.e. Stability

In a simple linear model, one can test for stability by solving the characteristic equations for the roots. Stability means simply that over time the variables in the model will come to rest at an equilibrium position if they are moved off an equilibrium position by an exogenous shock. In an unstable model, the variables will forever move away from an equilibrium if once disturbed.

Large complex models are more likely to be unstable because of the interaction of the equations in the determination of values for the variables. Unfortunately, for large models which are usually nonlinear, one cannot simply solve the characteristic equations. Stability can only be determined by "putting the model through its paces" in a series of simulations covering as long a period of time as feasible and covering as much variation in the exogenous variable values as plausible. In this way, one develops a "sense" of the model's stability properties.

A little bit of instability is not necessarily a bad property for a model to have. The real world, after all, is not always stable and does not always conform to the comparative static framework of the neoclassical economist. Exogenous changes to the system do not occur sequentially nor are factors, technology, tastes, etc., constant over time.

IV. Model Updates and Changes

Model updating is carried out any time that new data points or new variables become available or when economic theory and model results suggest that the present formulation of the relationship between the variables is unreasonable. As with model development, there are several criteria for judging the value of a potential model change. One weighs the criteria on the basis of what the model will be used for. The choice will probably result in a tradeoff among the criteria. This is the sense in which econometric modeling is an art.

In a model that is being used primarily for policy analysis rather than prediction, the t statistics are more important than R^2 and theoretical reasonableness is more important than low MAPE values. In predictive models, the opposite would probably hold true.

* * * * *

Several important observations derive from this discussion:

1. The more complex a model is in terms of variable interrelationships, the more likely it is that low R^2 will be encountered with some equations, MAPE values may be poor, and instability becomes a potential problem. Generally, the richness of model detail outweighs these concerns.

2. In a complex model, an individual equation must be analyzed in the context of the whole model rather than "out of context."

3. Because of multiple criteria for determining model reasonableness, each modeler assigns his own weights to the individual criteria in model construction. Thus, each model bears the imprint of the designer.

4. Choosing a structural form for an equation or deciding whether to include or exclude a specific variable in a particular equation is never a straightforward matter.

5. There is no perfect model which absolutely satisfies all criteria. All can be criticized and improved upon. But because no model completely satisfies all criteria does not imply the models are not useful.

Scott Goldsmith
University of Alaska
October 20, 1978

Comments on
Relation of Nonpetroleum Revenues to Personal Income
In the MAP Model Simulation of Alpetco Impact

1. I am tickled that someone has actually taken the time to get past the first page of the Alpetco study and to look at the analysis.

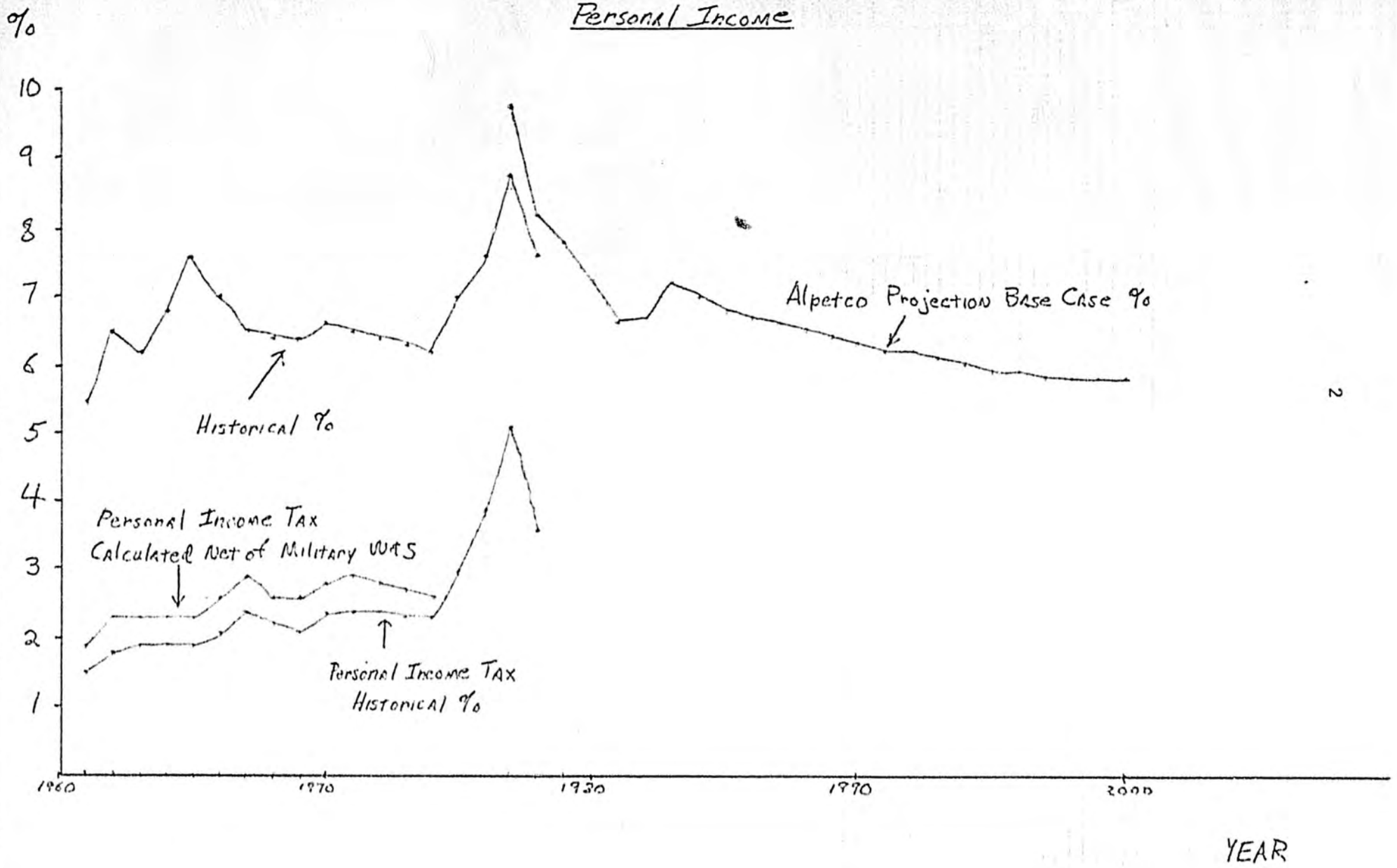
2. I agree that more responsive models of personal and corporate income taxes would be preferable. The basic problem is data. At present, the only data available on the state personal income tax is total collections, gross and net. Data on such basics as number of taxpayers and amount of tax paid from out-of-state addresses is not available. Brad Tuck and others will attest to the fact that economists have been asking Department of Revenue to pull information off the personal and corporate income tax returns for at least ten years, and no progress has been made. (This data would have much broader application than better estimation of tax models and would be extremely valuable.) In the absence of this data, one must try to construct Alaskan series from the information collected off federal returns. The basic difficulties with the approach are that the historical series have unexplainable large variation over time and provide information only on returns filed from Alaska and not for all income earned in Alaska.

3. In spite of these problems, I do not agree that one should revert to the analysis of aggregate past trends in the determination of endogenous revenues. A more systematic approach such as is developed in the MAP model is appropriate.

4. Looking at the past pattern of endogenous revenues in relation to personal income in Alaska in Table 2 of Barker, I do not observe a definitive, long-term trend emerging from the data. The points, if plotted on a graph, would be as shown in Figure 1.

Figure 1.

Endogenous Revenues
As Percentage of
Personal Income



5. Turning next to the base case projections in the Alpetco analysis, several points should be mentioned.

a. The major portion of the percentage decline in endogenous revenues compared to personal income occurs in the years immediately following Alyeska when the percentage declines from 9.8 (1977) to 6.6 (1981). This series is also included in Figure 1 for comparison purposes.

b. The differences between the historical figures and projection figures in the overlapping years indicate that the projection series contains some revenue items not in the historic series. In fact, the model value for endogenous revenues of $385 million in 1977 is quite close to the $362 million indicated by Barker. The personal income projection of the model for that year was somewhat low, and this tends to inflate the difference in the series.

c. The income elasticity of endogenous revenues is the weighted average of the elasticities of all taxes and revenues. Some such as the school tax and alcohol tax have clearly been income inelastic historically, thus requiring an elastic response in the larger taxes if an overall elasticity of one is to be observed.

d. Some upward movement in the ratio of personal income tax to personal income can be observed from the historic data. (See Figure 1.) Some of this would be the result of the declining importance over time of military wages which are not taxable. (See Figure 1.) Long-run projections of the national economy do not project a continuing increase in the percentage of personal income going into the federal income tax primarily

because of periodic changes in the tax laws to reduce the impact on the average effective rate of inflation and real income increases interacting with the progressive schedule. (It is important to avoid a fallacy of composition here. The effective rate for an individual may increase over time, and yet the effective rate for the population remains unchanged.) In addition, there may be a reason to expect the effective rate in Alaska to fall slightly in the projection period as the structure of employment shifts relatively away from high wage occupations in the petroleum and construction industries.

6. There is obviously an element of arbitrariness involved in presuming to project revenues over a 25-year period. The approach in the MAP model is to model the existing structure as much as possible and where possible make structural shifts in the future consistent with such shifts in the past. For example, historically the standard deduction has increased over time. This increasing trend is included in the projections. This appears to me to be a neutral approach and furthermore justified on the basis of the experience of the last legislature (federal and state) during which both the personal income tax and the business license tax were reduced. Since the state personal income tax essentially "piggybacks" the federal tax, this year Alaskans have been able to take advantage of not only a federal cut which affects state tax rates but also direct state-initiated cuts.

7. With respect to the impact on endogenous state revenues of the Alpetco project, several points should be noted.

a. The ratio of personal income tax to personal income would not be expected to increase in the Alpetco years to the same extent as in the Alyeska years, because the average wage of impact employment in the Alpetco case would be considerably below the Alyeska case.

b. The income tax model should be more responsive to short-run changes in per capita income. To this end, a different version of the state personal income tax model is being incorporated into the model which will better be able to distinguish between an increase in personal income resulting from an employment increase and one resulting from a wage increase. In general, the latter would have a more strongly positive impact on tax revenues. (See Scott Goldsmith, "A State Personal Income Tax Simulation Model," MAP working paper.)

c. In this context, it is useful to distinguish a marginal change measured as the impact within a year from the marginal change measured as the year-to-year change. I have a difficult time interpreting the latter when it is the change in personal income tax as a percentage of the change in personal income and a value in excess of 14.5 percent, the maximum marginal tax rate, is calculated.

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TYPES OF MODELS AND ANALYSIS OF IMPACT

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Much of the work performed by regional economists involves tracing the economic impacts of specific exogenous actions through the regional economy. The impacts of tax structure changes, of the location of new industry, or of increases in export markets are common examples of this type of study.

Three types of models are available to assist the researcher in this work--economic base models, input-output models, and econometric models. Each is best suited for particular problems and situations. The economic base model is the easiest of the three to construct and use, requiring in its simplest formulation only that the basic and nonbasic sectors of the economy be identified by one of several established techniques. The ratio of nonbasic to basic activity becomes the estimate of activity which would be generated by an increase in basic activity. The simplicity of the model means that it can be widely used but also presents problems which severely limit its usefulness as the change being analyzed increases in size and/or occurs within a time dimension. The use of a single unit of measure of economic activity such as employment is misleading, since different industries can have very different levels of average wages with very different effects. The identification of basic and nonbasic sectors is a problem. Finally, the model assumes a constant basic/nonbasic ratio which is clearly not realistic over time.

The input-output model provides much more detail on the interrelationships within a regional economy and can trace the impact of a change in much greater detail than an economic base model. Differential impacts from changes in different sectors of the economy can be traced.

Data requirements are the largest problem in model implementation, although techniques have been developed to make input-output models transferable from region to region. The basic conceptual problem with these models is the assumption of constant coefficients which rules out economies of scale, other types of agglomeration economies such as urbanization, and technological change. This is not a problem in the short run but does introduce bias in any long-run analysis.

Econometric models of regions are not confined to the theories of regional growth implicit in either the economic base or input-output type models but are more flexible in terms of being able to apply other components of regional economic theory to the analysis of impact. Many adopt concepts from the economic base models, but a variety of factors can be handled within the econometric framework which are important in regional economic analysis, but which are not capable of being handled in the other model types.

Some of these capabilities include the ability to handle a changing ratio of basic to nonbasic employment, to incorporate a fiscal sector into the model of the economy, to include relative regional prices in the model, to differentiate the impacts of employment and wages, and to handle the determination of personal income and population based on activity within the region.

Econometric models have data requirements falling somewhere between those of economic base studies and input-output analyses. A basic problem from which they suffer is the availability of sufficiently long, stable, and accurate time series data to enable the researcher to adequately specify his relationships.

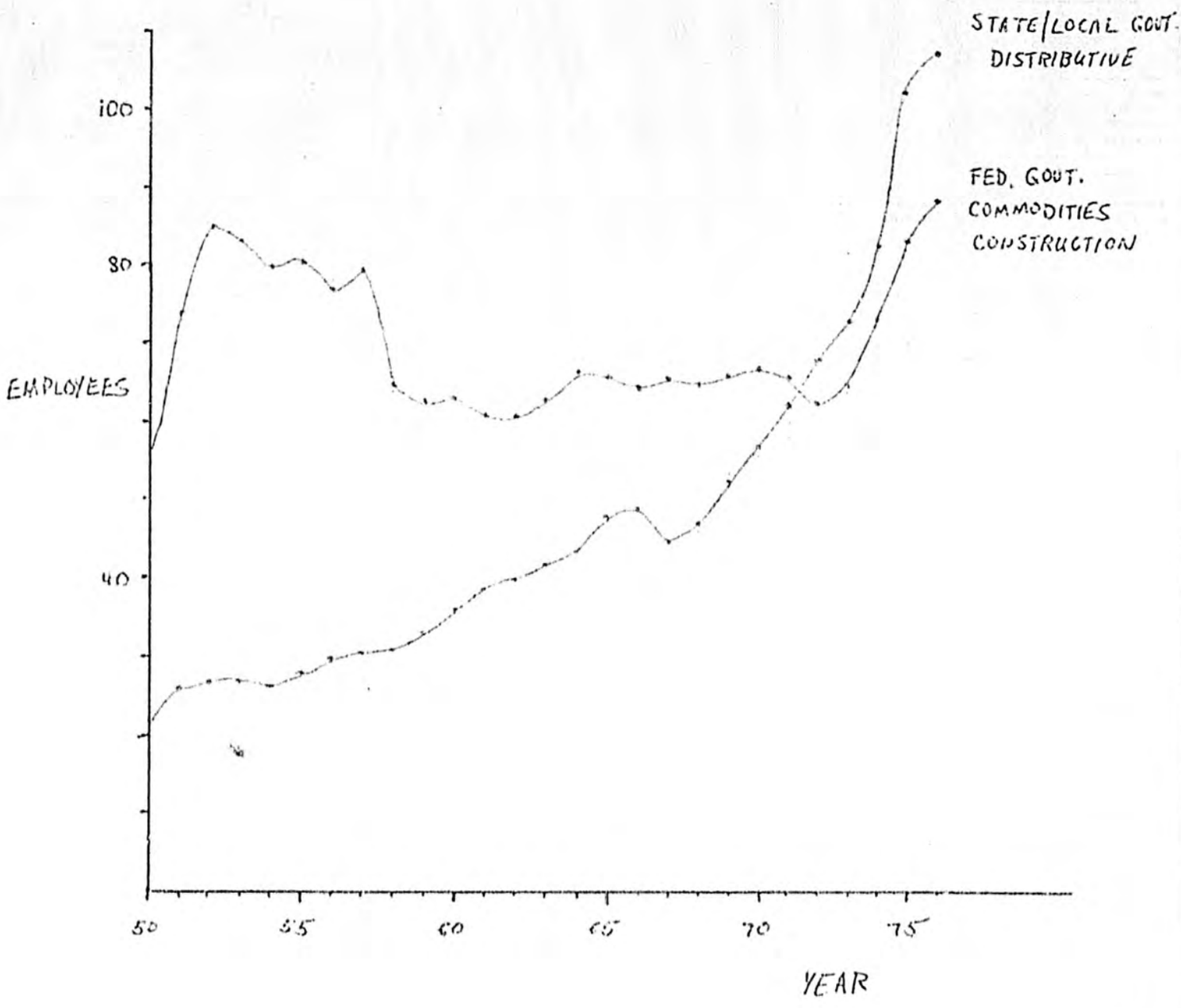
What sort of a model is best suited for identifying economic impacts in the Alaskan economy? For several of the reasons just mentioned, econometric models seem to have the most flexibility and the ability to

incorporate the widest range of factors when large multi-year impacts are being measured. In addition, one of the most important aspects of the Alaskan economy, the fact that it is underdeveloped but rapidly growing, cannot be reflected properly by the other model types. Inability to handle this basic feature greatly distorts long-run impact analyses done by these models.

To indicate the Alaskan dimension of this characteristic of an underdeveloped but growing economy, Figure 1 shows the growth since 1950 of the basic and support sectors in Alaska measured by employment. One may disagree over the proper classification of an industry as basic or nonbasic, but the overall pattern is unmistakable. The relationship between the basic and support sector employment has clearly changed dramatically over the years. Whereas in 1950 there were 39 employees in the distributive industries and state and local government for every 100 in the basic sector, in 1976 there were 121. The change over the period amounted to 267 distributive and state and local employees for every 100 in the basic sectors. This marginal ratio of 2.67 is quite different from the average ratio in 1950 of .39. Thus, any long-run analysis in 1950 applying the average nonbasic/basic ratio of that year to the economy and projecting into the future would vastly underestimate actual growth. In the same manner, it would underestimate the level of impacts in a growing economy.

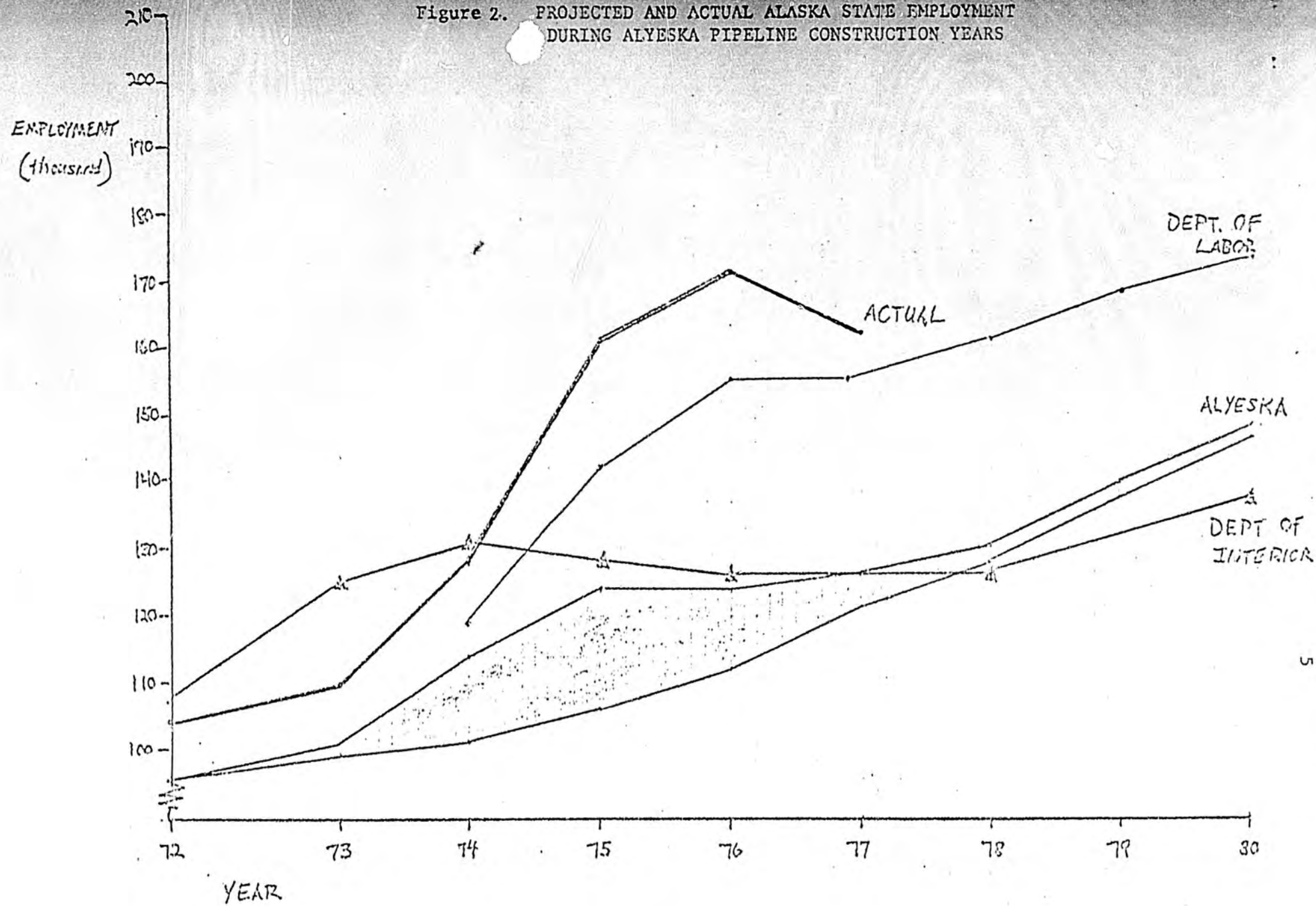
This mistake was definitely a factor in the underestimation of impacts for all a priori analyses of the Alyeska pipeline. As shown in Figure 2, all analyses done before the project completion underestimated the short- and long-run impact of the project substantially, partially because economic base models were employed which did not properly take account of the fact that growth changed the economy qualitatively as well as just increased its size. The actual impact could be called "blip-ratchet," whereas the economic base model describes the "blip" impact as shown stylistically in Figure 3.

Figure 1



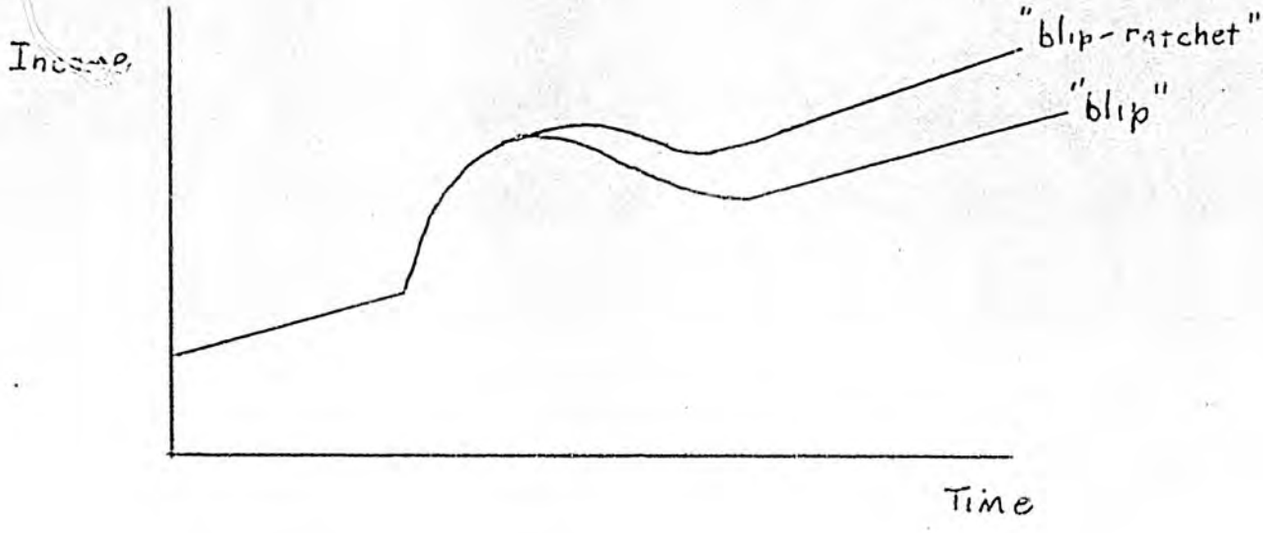
Adopted from Scott Goldsmith and Lee Huskey, "Structural Change in the Alaskan Economy: The Alyeska Experience," paper presented at the 29th Alaska Science Conference, August 15, 1978, Table 1.

Figure 2. PROJECTED AND ACTUAL ALASKA STATE EMPLOYMENT DURING ALYESKA PIPELINE CONSTRUCTION YEARS



Source: Scott Goldsmith and Lee Huskey, "Structural Change in the Alaskan Economy: The Alyeska Experience," paper presented at the 29th Alaska Science Conference, August 15, 1978.

Figure 3.



The difference in the level of economic activity after A between the "blip" and "blip-ratchet" cases is the impact attributable to structural change in the economy. This is essentially a change in the ratio of support to basic industry. Because of a variety of factors including economies of scale from increased market size, other agglomeration economies, reduced transport costs, changed expectations of growth, availability of capital, etc., there has been a "deepening" of the support sector--import substitution--rather than just an increase in its level, indicated by the shaded area.

This import substitution can be interpreted in two ways with respect to the analysis of impact of specific exogenous changes. On the one hand, the import substitution would presumably have occurred anyway at some future time, assuming continued growth of the economy, and the exogenous change merely altered the timing of the import substitution. This reasoning would argue that the import substitution that results after the exogenous change should not be counted as part of the impact

of the exogenous change but rather independently as part of the normal growth process. The alternative interpretation is that the import substitution was in fact the result of the exogenous change and should be counted among the project impacts.

The distinction is critical when one is doing a benefit-cost analysis of a project from a public perspective. The benefits and costs associated with the import substitution component of impact will generally not cancel one another out. Thus, their treatment could be critical in determining the outcome of the analysis. It seems clear that the import substitution effects of exogenous changes are correctly classified as impacts, and as such, it seems reasonable to weigh these impacts like all others as part of any benefit-cost analysis.

Alpetco Petrochemical Proposal: Impact Analysis

Supplement

The results of the Alpetco impact analysis depend significantly on the assumptions made in the base case and Alpetco scenarios. In both the base case and the Alpetco scenario, important assumptions concerning the relationships between variables and the direct effect of Alpetco were made. One benefit of using the MAP model in analyzing the Alpetco impact is that it allows relatively easy testing of the sensitivity of the results to changes in these assumptions. Since the publication of the Alpetco Impact report, suggestions of further sensitivity tests have been made. This supplement will present comparative results of four of these tests. The results will be compared in terms of the impacts on population, employment, real per capita state expenditures, and the general fund current account. These results are presented in Tables S.1 through S.4.

The importance of the effect of induced state expenditures on the impact generated by Alpetco suggests that the rule used to determine the level of state expenditures be examined. The first three sensitivity tests in this supplement examine the effect of changing the state spending rule. In the original Alpetco and base case scenarios, state spending was assumed to increase with prices, population, and personal income. Increases in response to changes in personal income expand the level of state services (measured by real per capita expenditures), while changes in response to increases in prices and population maintain the same level

of services. To test the sensitivity of the Alpetco impact to changes in the level of state expenditures induced by it, we examined the case (ALS9) when expenditures increased over the base case levels only because of changes in prices and population. The second sensitivity test (ALS10) examined the effect of a differential response of state expenditures during the construction period and the operations period of the Alpetco project. State expenditures were assumed to remain at their base case levels until after the end of construction in 1984, when they increased with population and prices. In the third sensitivity analysis (ALS13), the increase in total state expenditures was assumed to be constrained to equal the increase in general fund revenues (lagged one year) which result from the growth of the economy because of the Alpetco project. The comparison of these results should provide an idea of the effect of state government expenditures on the Alpetco impact.

The final sensitivity test analyzes the case where a substantially higher level of corporate income taxes is generated by Alpetco than assumed in the basic simulations (ALS20). This test was based upon an Alpetco criticism of the calculation of corporate income tax in the basic analysis.

Constant Real Per Capita Expenditures (ALS9)

When state expenditures are held constant in real per capita terms at the level of the base case, the relative effects differ between the construction and operations periods. The population and employment

impacts are lower than in the regular Alpetco case during construction, but higher by the end of the period. By the end of construction in 1983, the employment impact is 2,700 less when state spending is constrained; this reduces the employment impact by 12 percent. The population impact is also reduced during the construction period; the population impact is 10 percent less in 1983. By 2000, the employment and population impacts are greater than in the regular Alpetco case. The employment impact is 30 percent greater and the population impact is 17 percent greater than in the regular Alpetco case. This results because the real per capita level of expenditures falls below the base case level in the regular Alpetco case after construction (beginning in 1986), which dampens the state expenditure effect of the increased population; this does not happen in this case as total expenditures increase with population. This is reflected in comparing the impacts on the current account of the general fund which is negative but smaller during construction, but is greater by 2000 than in the regular Alpetco case. The current account balance is $149.5 million less than in the regular Alpetco case by 2000.

No Expenditure Response Until After Construction (ALS10)

This case is similar to the previous one, except that state expenditures are unchanged from the base case during construction. State government services only increase in response to changes in long-run or permanent employment and population change induced by the Alpetco project. Eliminating the construction phase response reduces the population

impact by the end of construction in 1983 by 32 percent. The employment impact is reduced by 37 percent by the end of construction. Even though state expenditures do not increase over base case levels during construction, the impact of Alpetco on the current account of the general fund becomes negative in 1984 and every year thereafter. The negative impact is much less than in the base case in early years.

Expenditure Increases Equal Revenue Increases (ALS13)

Introducing this rule for expenditures has the same type of effect on population and employment as the other cases. The population impact is less during construction and most of the years of operation, but greater by 2000. In 1983, the population impact is 22 percent less than in the regular Alpetco case. The employment impact follows the same pattern, being 25 percent lower than the regular Alpetco case in 1983. In 1990, employment slightly exceeds that of the basic Alpetco case.

This counter-intuitive pattern of response of employment and population in the long run is attributable to the fact that state expenditure growth in the base case is slightly depressed in later years because real personal income growth is moderating. The net fiscal impact is nonzero in this case because there is a lagged response of expenditures to changes in revenues. It is positive in those years when revenues from Alpetco are increasing and negative when they are declining.

The impact on real per capita state expenditures in this case is negative. The impact is significant during the construction years and

declines abruptly after completion. In 1990, it represents a reduction of less than 1 percent from the base case.

Higher Corporate Income Tax Revenues (ALS20)

The final sensitivity analysis (ALS20) conducted is based upon a criticism by Alpetco concerning the estimated real state corporate income tax generated by Alpetco. They felt that an adjustment to real corporate income taxes from the project should be made which accounted for the fact that depreciation and interest expense occur at a fixed rate, which does not change with inflation. This affects only state revenues; expenditures, employment, and population are the same as in the regular Alpetco case. Because expenditures have remained constant while revenues have increased, the current account of the general fund can be expected to be affected positively. In fact, the negative impact on general fund current account is less after 1986 when production begins than in the regular Alpetco case, and by 2000 the impact on the general fund current account is positive; it is $23.5 million greater than in the base case.

Table S.1.

Alpetco Population Impact Under Alternative Assumptions

(thousands)

	AL2_ER	ALS9_ER	ALS10_ER	ALS13_ER	ALS20_ER
1979	1.944	2.015	1.944	1.944	1.944
1980	7.015	7.517	6.129	6.295	7.015
1981	20.21	21.461	17.279	18.042	20.21
1982	29.968	28.024	21.794	23.924	29.968
1983	36.749	33.237	25.061	28.633	36.749
1984	31.333	23.726	20.825	21.584	31.333
1985	26.562	22.451	20.278	20.13	26.562
1986	24.896	23.078	21.047	19.571	24.896
1987	24.509	23.888	21.955	20.596	24.509
1988	24.585	24.675	22.827	21.707	24.585
1989	24.889	25.504	23.732	22.625	24.889
1990	25.234	26.319	24.628	23.382	25.234
1995	27.781	30.979	29.572	27.103	27.781
2000	24.966	29.261	28.203	26.055	24.966

AL2_ER = basic Alpetco assumptions
ALS9_ER = base case real per capita expenditures
ALS10_ER = no expenditure response until after construction
ALS13_ER = expenditure increases equal revenue increases
ALS20_ER = higher corporate income tax revenues

Table S.2.

Alpetco Employment Impact Under Alternative Assumptions

(thousands)

	AL2_ER	ALS9_ER	ALS10_ER	ALS13_ER	ALS20_ER
1979	1.494	1.525	1.494	1.494	1.494
1980	5.083	5.442	4.404	4.531	5.083
1981	14.287	15.18	12.119	12.687	14.287
1982	19.514	17.884	13.549	15.102	19.514
1983	22.253	19.584	14.13	16.656	22.253
1984	15.422	9.848	8.918	9.045	15.422
1985	10.587	8.236	7.969	7.305	10.587
1986	8.721	8.315	8.007	6.503	8.721
1987	8.095	8.587	8.292	7.055	8.095
1988	7.946	8.869	8.578	7.665	7.946
1989	8.036	9.206	8.914	8.109	8.036
1990	8.196	9.557	9.269	8.438	8.196
1995	9.694	11.78	11.482	10.095	9.694
2000	7.506	9.785	9.609	8.687	7.506

AL2_ER = basic Alpetco assumptions
ALS9_ER = base case real per capita expenditures
ALS10_ER = no expenditure response until after construction
ALS13_ER = expenditure increases equal revenue increases
ALS20_ER = higher corporate income tax revenues

Table S.3.

Alpetco Impact on State Current Account
Under Alternative Assumptions

(million $)

	AL2_ER	ALS9_ER	ALS10_ER	ALS13_ER	ALS20_ER
1979	1,906	-5,498	1,906	1,905	1,906
1980	-6,576	-16,677	10,888	6,925	-6,576
1981	-27,338	-52,944	30,386	13,261	-27,338
1982	-112,469	-65,626	54,944	6,318	-112,469
1983	-164,99	-93,941	66,169	-12,122	-164,99
1984	-221,881	-57,167	-28,555	-34,377	-221,961
1985	-142,006	-78,553	-42,474	-34,948	-142,012
1986	-89,527	-67,803	-28,419	7,385	-81,913
1987	-64,957	-62,493	-20,161	6,293	-52,7
1988	-58,613	-66,845	-21,416	-1,739	-43,198
1989	-57,366	-73,454	-24,694	-4,917	-38,532
1990	-58,898	-82,898	-30,548	-7,207	-36,265
1995	-76,37	-145,81	-71,138	-11,057	-31,672
2000	-48,13	-197,716	-92,358	-12,44	23,5

AL2_ER = basic Alpetco assumptions
ALS9_ER = base case real per capita expenditures
ALS10_ER = no expenditure response until after construction
ALS13_ER = expenditure increases equal revenue increases
ALS20_ER = higher corporate income tax revenues

Table S.4.

Alpetco Impact on Real Per Capita State Expenditures
Under Alternative Assumptions

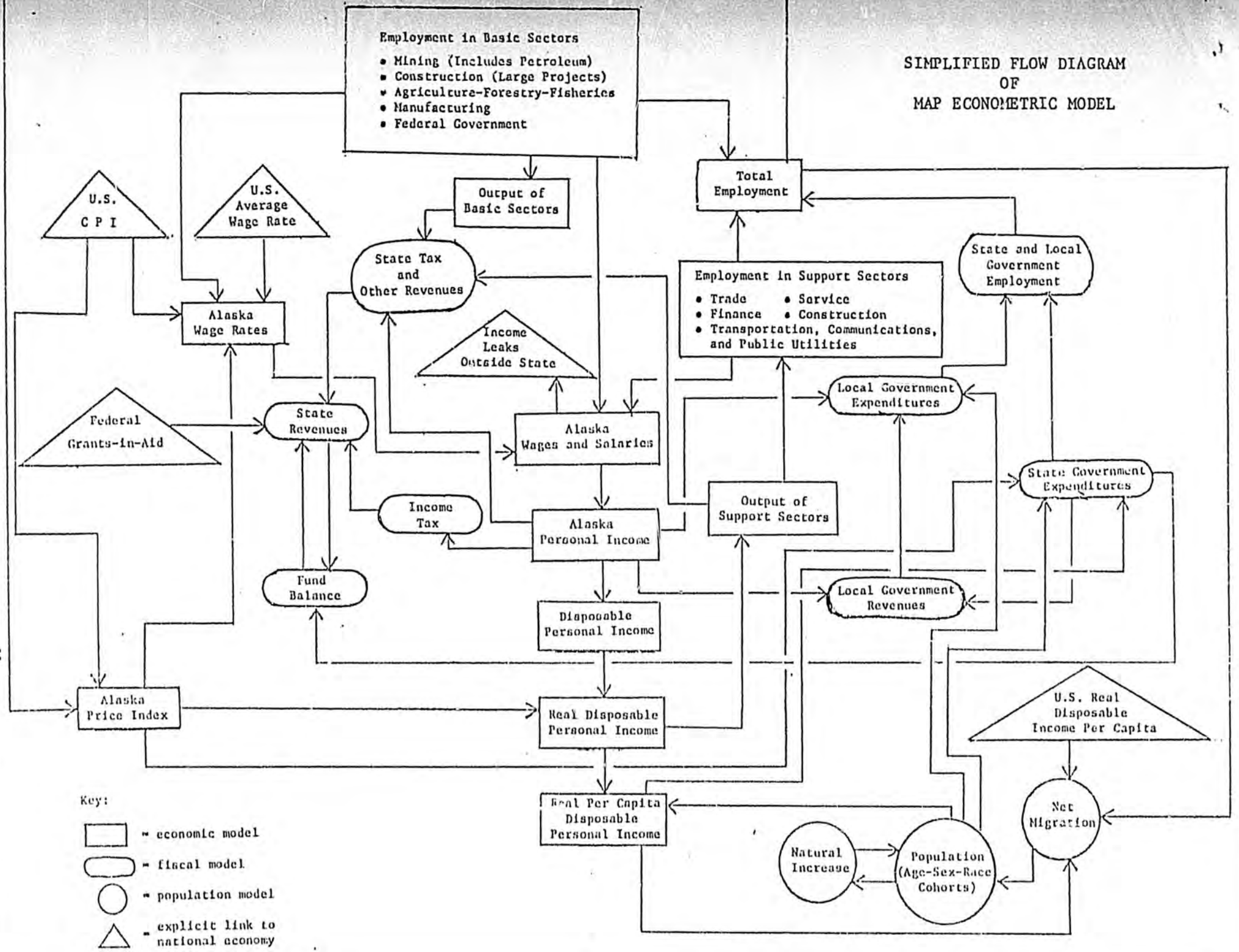
(1967 U.S. $)

	AL2_ER	ALS9_ER[1]	ALS10_ER	ALS13_ER	ALS20_ER
1979	-7.12	-0.108	-7.12	-7.119	-7.12
1980	-8.01	-0.39	-20.793	-16.943	-8.01
1981	-18.109	-1.049	-54.531	-41.41	-18.109
1982	24.777	-1.328	-68.411	-35.007	24.777
1983	35.012	-1.61	-82.235	-35.073	35.012
1984	93.279	-1.031	-0.915	2.543	83.279
1985	24.563	-0.973	-0.885	-10.406	24.563
1986	-1.62	-0.992	-0.91	-23.731	-1.62
1987	-12.433	-1.025	-0.942	-18.203	-12.433
1988	-16.939	-1.058	-0.979	-13.352	-16.939
1989	-18.929	-1.089	-1.018	-11.717	-18.929
1990	-20.27	-1.126	-1.056	-11.643	-20.27
1995	-21.775	-1.291	-1.232	-14.508	-21.775
2000	-25.058	-1.162	-1.116	-10.542	-25.058

[1]Difference from base caused by the definition of current expenditures. This is not a significant difference from the base case.

AL2_ER = basic Alpetco assumptions
ALS9_ER = base case real per capita expenditures
ALS10_ER = no expenditure response until after construction
ALS13_ER = expenditure increases equal revenue increases
ALS20_ER = higher corporate income tax revenues

SIMPLIFIED FLOW DIAGRAM OF MAP ECONOMETRIC MODEL



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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

EL PASO ALASKA COMPANY, ET AL.) Docket No. CP75-96, et al.

ATLANTIC RICHFIELD COMPANY RESPONSES TO INTERROGATORIES

I. POLICY

QUESTION 1. Were you ever a member of a group investigating the feasibility of bringing gas from Prudhoe Bay and/or the Mackenzie Delta to the Lower 48 states?

ANSWER 1. Yes.

QUESTION 1. a. If yes, please describe your participation in the group.

ANSWER 1. a. Atlantic Richfield Company has participated in two such feasibility studies. Atlantic Richfield joined with El Paso Natural Gas Company in a study to determine the economic feasibility of bringing gas from Prudhoe Bay to the West Coast of the United States by means of a trans-Alaska gas pipeline, gas liquefaction and regasification facilities and LNG tankers. Atlantic Richfield contributed its expertise and financial support to this study from April 23, 1973 to October 23, 1974.

Atlantic Richfield has participated in a study to determine the economic feasibility of bringing gas from Prudhoe Bay and the Mackenzie Delta by means of a trans-Canadian pipeline to markets in Canada and the Lower 48 states. Atlantic Richfield contributed its expertise and financial support to this study from July 14, 1970 to November 30, 1975.

QUESTION 1. b. Are you still a member of such a group; and if not, please explain the reasons for departing.

ANSWER 1. b. No. Atlantic Richfield withdrew from these groups since we felt that the purpose for which we had joined, i.e., to determine the feasibility of transporting arctic gas to the Lower 48 states, had been accomplished and that our further participation was unnecessary. We continue to cooperate with both groups.

QUESTION 2. Why haven't firm gas purchase contracts been executed for Prudhoe Bay?

ANSWER 2. As a result of the FPC's Order of December 31, 1975, in Docket R-411, et al., and subsequent action by the California PUC in, sua

sponte, reopening of CPUC decision #84729, Atlantic Richfield's funding agreement with Pacific Lighting Development Company (PLGD), which gave PLGD a call on 60% of its Prudhoe Bay gas, has been terminated. Our advance payment agreements with Texas Eastern Transmission Corporation and Panhandle Eastern Pipeline Company covering the remaining 40% of Atlantic Richfield's Prudhoe Bay gas will be terminated should the FPC Order become final. Under present circumstances we have no basis for negotiation of a definitive gas purchase contract. Neither unit agreements nor a plan of development for the field have been formally submitted to or approved by the State of Alaska.

Additionally, in light of certain language appearing in the Commission's Order of December 31, 1975, in Docket No. R-411, et al., we are uncertain as to whether any gas purchase contract would be certificated or if the Commission would require a full-blown allocation case for North Slope gas.

QUESTION 3. Please explain the relationship of a unitization and operation agreement for Prudhoe Bay to the execution of gas purchase contracts.

ANSWER 3. The Prudhoe Bay Field consists of a gas cap and an oil rim. The field has a diversity of ownerships in the tracts with differing interests in the gas cap and oil rim. Efforts are underway to unitize the entire field so that it might be developed and operated in the most efficient manner. The plan of development agreed to by the producers must then be approved by the State of Alaska. Until such time as these events occur, it is not known what precise amount of gas production and oil production will be owned in the unit by each party nor is it known to what extent and at what time the State will permit gas sales.

QUESTION 4. Do you have any present intention to provide equity for either the El Paso Alaska project or the Arctic-Canadian gas project should either of them be issued a certificate?

ANSWER 4. No.

QUESTION 5. If the natural gas pipeline and distribution companies are unable to commit the amount of equity required by lendors as necessary for either the Arctic Gas or the El Paso project, would your company be willing to help provide some of the needed equity?

ANSWER 5. A decision on the question would be dependent upon conditions at the time such a need becomes apparent; however, it seems highly unlikely that our other capital requirements would permit such an investment.

QUESTION 6. Will your company bear the cost of gathering and treatment facilities on the North Slope? If no decision has been made on this, what factors would influence a decision and by when would such a decision have to be made?

ANSWER 6. The cost of gathering and treatment facilities on the North Slope will be borne in accordance with gas purchase contracts yet to be negotiated. Under our remaining advance payment agreements (which will be terminated in the event the Commission's Order issued December 31, 1975, in Docket No. R-411, et al., becomes final), Atlantic Richfield would bear the initial cost of installing the gas gathering system but would have the option to require the gas purchaser to purchase all gas handling facilities. A decision relative to exercising such option would have been made at the proper time in light of circumstances existing at the time. It was contemplated that the gas conditioning

plant (treatment facilities) would be installed and operated by or for the gas purchasers.

QUESTION 7. Can your company categorically guarantee that the purchase price of Prudhoe Bay gas under future gas purchase contracts would be no higher than the commodity price of gas in the market area to be served adjusted for applicable cost to market?

ANSWER 7. No. So long as the price of natural gas sold for resale in interstate commerce is subject to Federal Power Commission regulation, producers will receive no more than the regulated price permitted at the wellhead. In the event of price decontrol, Atlantic Richfield hopes to receive fair market value at the wellhead for its gas. The commodity price (which is subject to many variables) of gas in any particular market area to be served, adjusted for applicable delivery cost to that market, may or may not have relevance in determining the regulated rate or fair market value at the wellhead.

QUESTION 8. Would your company oppose any attempt by a potential gas purchaser to place a minimum daily delivery volume provision in a gas

purchase contract for the Alaskan North Slope?

ANSWER 8. Yes. We cannot guarantee to deliver any specific volume of gas at any period of time. As mentioned in answer I, 3., the unitization agreement and State action will have a bearing on the volume of gas that can be sold by each company at Prudhoe Bay. As in all oil or gas fields, it is impossible to preduct with certainty what volume of gas will be available from day to day.

QUESTION 9. How did you choose or how will you choose a purchaser or purchasers for your Prudhoe Bay gas? Explain the steps that will be taken or have been taken in this matter.

ANSWER 9. In July, 1974, Atlantic Richfield sent letters to 17 prospective gas purchasers, requesting bids for its share of the natural gas in the Prudhoe Bay Field. With the FPC's Order No. 499 advance payment program in mind, Atlantic Richfield stated that it was interested in offers which include interest-free loans repayable over time as gas is delivered.

Eleven of the 17 companies responded by making offers for Atlantic Richfield's Prudhoe Bay gas. Interstate pipeline companies generally offered to make advance payments

pursuant to Order No. 499 in the form of interest-free loans. Pacific Lighting Gas Development Company (PLGD) offered to make an advance payment for Prudhoe Bay gas, but stated that it was not feasible for PLGD to raise the funds needed to make an interest-free loan. Instead, it offered to make payments to Atlantic Richfield to cover the interest expense and other costs associated with Atlantic Richfield's raising the money through the sale of a production payment.

The offers made by Pacific Lighting Gas Development Company (PLGD), Panhandle Eastern Transmission Corporation and Texas Eastern Pipeline Company, most nearly fulfilled Atlantic Richfield's needs and we proceeded to conclude agreements with them. As noted in the answer to question I (2), the PLGD agreement has been terminated and if the FPC's Order in Docket R-411, et al., becomes final, the remaining advance payment agreements will be terminated. All of these agreements expressly recognize that certification and construction of either of the

proposed Alaskan Gas transmission systems would be satisfactory to both seller and buyer.

In light of the confusion brought about by the Commission's Order in Docket No. R-411, et al., and other uncertainties existing at this time, Atlantic Richfield is in the process of reevaluating all options open to it and has made no decision as to its future action.

II. RESERVES

QUESTION 1. Please describe your exploration and development activities on the North Slope of Alaska through 1975 indicating, among other things, the following:

a. Total amount of acreage held in Prudhoe Bay Field as defined by the Alaska Oil and Gas Conservation Committee;

ANSWER 1. a. Atlantic Richfield Company holds interests in 181,689 gross acres or 94,490 net leasehold acres in the Prudhoe Bay Field as defined by the Alaska Oil and Gas Conservation Committee.

QUESTION 1. b. Number of wells presently drilled in the Prudhoe Bay Field and the success ratio of well completions;

ANSWER 1. b. Fifty-three wells have been drilled on the Atlantic Richfield Company/Exxon Company, U.S.A. acreage in the Prudhoe Bay Oil Pool limits. Six of these wells are not commercial.

QUESTION 1. c. An estimation of the total amount of gas reserves in Prudhoe Bay held by your company and an estimate of its deliverability;

ANSWER 1. c. DeGolyer and MacNaughton, our reserve consultant, has estimated that the proved gas reserves in the Prudhoe Bay Field total 24 Tcf of hydrocarbon gas, with Atlantic Richfield Company's net share calculated to be in excess of 7.08 Tcf. Atlantic Richfield's share of the gas deliverability from Prudhoe Bay Field will depend on the outcome of unitization. Insofar as the total field is concerned, gas production will begin with the start of oil production; but gas sales cannot begin until the gas transportation system is built, gas conditioning facilities constructed and a plan of operation which includes gas

sales is approved by the working interest owners and by the Alaska Oil and Gas Conservation Committee.

QUESTION 1. d. Total amount of acreage held on the North Slope including the offshore area outside of Prudhoe Bay and location of such leases;

ANSWER 1. d. Atlantic Richfield holds interests in 817,734 gross acres or 417,016.41 net leasehold acres on the North Slope of Alaska including the offshore portion and the interest set out in answer II, 1., a., above.

QUESTION 1. e. Number of wells drilled outside of the Prudhoe Bay Field on the North Slope, including offshore areas, their location and an indication whether they were successful; and

ANSWER 1. e. Atlantic Richfield Company has participated in the drilling of 31 wells outside of the Prudhoe Bay Field on the North Slope through 1975. These wells, their location and results are as follows:

ARCO No. 1 Colville, 25-12N-7E, Dry and Abondoned (D and A)

ARCO No. 1 Itkillik, 10-8N-5E, D and A

ARCO No. 2 Kavik, 11-3N-22E, D and A

ARCO No. 3 Kavik, 8-3N-23E, gas

ARCO No. 1 Little Twist, 34-3S-4W, D and A

ARCO No. 1 Nora Federal, 5-2N-14E, D and A

ARCO No. 1 North Franklin Bluffs, 20-8N-14E, D and A

ARCO No. 1 Schrader Unit, 18-3S-5E, D and A

ARCO No. 1 Susie Federal, 22-2N-13E, D and A

ARCO No. 1 Toolik Federal, 4-8N-15E, D and A

ARCO No. 2 Toolik Federal, 5-8N-12E, D and A

ARCO No. 3 Toolik Federal, 4-8N-9E, D and A

ARCO No. 1 Ugnu, 22-12N-9E, oil

ARCO No. 1 West Sak River, 2-11N-10E, oil

ARCO No. 2 West Sak River, 22-11N-10E, oil

ARCO No. 3 West Sak River, 26-11N-9E, oil

ARCO No. 5 West Sak River, 11-10N-10E (confidential)

ARCO No. 6 West Sak River, 29-11N-11E (confidential)

Pan Am Kavik No. 1, 7-3N-23E, gas

BP East Ugnu No. 1, 17-2N-10E, oil

BP East Umiat No. 1, 19-1S-2E, gas

BP Kemik Unit No. 2, 6-1S-21E, D and A

BP Itkillik Unit No. 1, 11-1N-6E, D and A

BP Shale Wall Unit No. 1, 2-5S-5E, D and A

Exxon East Mikkelsen No. 1, 17-9N-21E, D and A

Forest Kemik Unit No. 1, 17-1N-20E, gas

Mobil Beli Unit No. 1, 8-4N-23E, D and A

Mobil Echooka Unit No. 1, 32-1N-16E, D and A

Mobil West Kadleroshilik No. 1, 14-5N-14E, D and A

Texaco East Kuparuk Unit No. 1, 10-2S-8E, D and A

Texaco West Kavik Unit No. 1, 20-5N-20E, D and A

QUESTION 1. f. Total amount of gas reserves estimated to be held on non-Prudhoe Bay field lease and their deliverability.

ANSWER 1. f. DeGolyer and MacNaughton, our reserve consultant, has not assigned any proved reserves on the North Slope outside the Prudhoe Bay Field.

QUESTION (cont'd.) 1. Explain the method and data used in determining any reserve estimates.

ANSWER 1. DeGolyer and MacNaughton has said that "since Prudhoe oil pool is essentially a shut-in field with no reservoir performance data, we have based our reserve estimates on the volumetric method. By volumetric method we mean that we have used individual well data -

logs, cores, fluid samples, and flow tests - to determine the sand thickness in each well and to determine certain average reservoir properties. We then used standard mapping techniques to determine the oil and gas in place throughout the field, including the Atlantic Richfield acreage. Then we have estimated an overall recovery factor based on our experience with other fields of similar reservoir characteristics."

QUESTION 2. Has your company made an independent estimate of the amount of potential reserves on the North Slope of Alaska? If yes, please describe your findings.

ANSWER 2. Yes. Atlantic Richfield has estimated the potential reserves yet to be discovered on the North Slope of Alaska using a method based on recovery factors times the cubic miles of sediment capable of containing hydrocarbons. The area included extends northward from the Brooks Range to the 300 foot water depth at the edge of the Continental platform in the Chukchi and Beaufort Seas. A large part of this area lies under the Polar ice cap. We estimate that recoverable reserves

could range up to 45 billion barrels of oil and 135 Tcf of gas. Estimates of potential reserves derived by this method for untested frontier areas are generally regarded as being optimistic.

QUESTION 3. Based upon your company's drilling experience to date, does it appear that the areal extent of the Prudhoe Bay Field as defined by the Alaska Oil and Gas Conservation Committee is larger than anticipated?

ANSWER 3. No. However, additional wells drilled on either Atlantic Richfield or other companies' acreage may allow the boundary to be moved.

QUESTION 4. Has your company studied the possibility of drilling in the Yukon-Kandik Basin, Middle Tanana Basin and Copper River Basin areas of Alaska? If yes, what do your studies indicate, what has been your past experience in such areas, if any, and what are your company's current and future plans with respect to such areas?

ANSWER 4. Yes, Atlantic Richfield has made evaluations of the Yukon-Kandik, Middle Tanana and Copper River Basins. Atlantic Richfield's experience in these basins has been as follows:

a. Yukon-Kandik Basin

Atlantic Richfield conducted a field program in the basin in 1962. Several areas of interest were found, however, the

structural fabric was complex and was accompanied with a very limited sedimentary section with good reservoir characteristics.

b. Middle Tanana Basin

No meaningful rocks are exposed in the basin for examination. A well drilled in the basin in 1962 revealed a thin, non-marine tertiary cover.

c. Copper River Basin

Atlantic Richfield drilled two of the eight wells in the Copper River Basin. We did not find significant shows of hydrocarbons in these wells, nor adequate amounts of reservoir quality rock. In addition, the presence of perma-frost and surficial volcanic rocks make it difficult to obtain the quality geophysical data necessary for pinpointing new drill site possibilities.

We have no current plans for additional evaluation of these areas.

QUESTION 5. With respect to oil production from the Prudhoe Bay Field, what are the anticipated deliverability rates for the first 12 years? Will this affect the deliverability of your gas? What effect would a 2.25 Bcf deliverability capacity pipeline have on oil production during this period?

ANSWER 5. The production rate for the early years in the Prudhoe Bay oil field will be limited by the completion, expansion and operation of the Trans-Alaska Oil Pipeline. In later years the oil production rate (as well as gas deliverability) will be determined by field performance. It is not possible to predict with certainty either of these events. Thus, the oil production rates which can be forecast today must be viewed only as reasonable estimates.

The Trans-Alaska Oil Pipeline is expected to begin operation in mid-1977 at 600 thousand barrels per day and reach a sustained throughput of 1.2 million barrels per day before the year's end. As yet, no agreement has been reached on pipeline expansion; however, this expansion could take place by the first of 1979. We have assumed that this expansion will take place as early as possible and have

projected a 1.5 million barrels per day production rate from the Prudhoe Bay Field commencing on January 1, 1979, and continuing until field performance can no longer sustain that rate. The field performance predictions used in this production forecast are based on numerical simulation studies conducted during the past five years. These studies have been conducted for several alternative methods of reservoir management. The studies have also considered the sensitivity to many of the reservoir unknowns. Based on these studies, Atlantic Richfield believes that the following is a reasonable projection for the oil production rate from the Jurassic-Triassic formation and is consistent with 2.0 to 2.5 BCF/D gas sales:

Prudhoe Oil Pool Production[1/] 1977-1988

Year	Rate, MB/D
1977	900[2/]
1978	1,200

(cont'd.)

1/ Production forecast for the Jurassic-Triassic crude oil only, does not include condensate or crude oil from other zones, such as Lisburne or Cretaceous formations.

2/ Average for the last six months of 1977.

(cont'd.)

Year	Rate, MB/D
1979	1,500
1980	1,500
1981	1,500
1982	1,500
1983	1,500
1984	1,500
1985	1,485
1986	1,280
1987	1,020
1988	900

QUESTION 6. Please describe your proposed exploration and development activities for the North Slope, if any, for 1976.

ANSWER 6. A. Exploration

Atlantic Richfield will continue its geological studies on the North Slope during 1976. The Company plans to drill four exploratory wells in search of oil. We have no plans for geophysical work on the North Slope this year.

B. Development

Atlantic Richfield will be drilling development wells with two rigs through-

out 1976. This activity should result in the completion of 20 to 22 wells. In addition, eight to 10 gas injection wells will be drilled and existing wells will be completed and perforated for production.

III. FACILITIES AND COSTS

QUESTION 1. What is the type of gas that will be produced from your Prudhoe Bay leases?

ANSWER 1. Solution gas and gas cap gas will be produced.

QUESTION 2. What type of facilities would be needed to process and/or treat each type of gas?

ANSWER 2. Gas handling and conditioning facilities will be required. The gas handling facilities include the gas compression and treating facilities at the flow stations as well as the gas gathering pipelines, compression facilities, gas injection pipelines and injection wells. The gas conditioning facilities will include equipment to achieve dehydration and removal of excess liquids and carbon dioxide from the gas.

QUESTION 3. Which facilities mentioned in interrogatory 2 will be constructed and operated by the producer and which will be required to be purchased entirely or partly by pipeline purchaser? Who will operate those owned by the pipeline?

ANSWER 3. Our advance payment agreements contemplated that the producer would construct and the gas purchaser would acquire, at Atlantic Richfield's option, those gas handling facilities from the outlet of the oil and gas separators and flash tanks at each flow station or separation center to the gas conditioning plant. No decision was made and no discussions were held as to who would operate these facilities. The gas conditioning plant (at the entrance of the gas pipeline system) would have been constructed and operated at the expense of the gas purchaser or the gas pipeline system.

These agreements have been or will be terminated if the FPC Order becomes final.[3/]

QUESTION 4. What is the quality of the gas at the wellhead and what will be the acceptable quality for pipeline delivery?

ANSWER 4. The gas at the wellhead, in addition to containing the basic hydrocarbon constituents, also contains approximately 12% CO_2 and will

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3/ See Answer I, 2.

be saturated with water. Although this gas could be delivered to a pipeline specifically designed to handle this quality of gas, gas purchasers (or transporters) will probably condition the gas to meet such requirements as the gas transportation system may determine.

QUESTION 5. It is noted that certain agreements between various producers on the North Slope and pipeline purchasers reserve the right of the producer to process Prudhoe Bay gas in the Lower 48 states. What type of processing is contemplated by your company, where, when and how much? What type of transportation arrangements would be necessary to implement this provision?

ANSWER 5. At the present time, Atlantic Richfield does not have in mind any specific plans for processing in the Lower 48 states. Any transportation arrangement would have to be made with the gas purchaser and gas transporter and presumably approved by the FPC.

QUESTION 6. What would be the cost of each separate facility mentioned in interrogatory 2 ?

ANSWER 6. The current estimates of costs of the gas handling and conditioning facilities are $1.333 billion and $877 million respectively. It should be noted that it is extremely difficult to estimate these costs at this

time due to the uncertainties of the timing of these facilities and the cost inflation which will occur prior to installation of the facilities.

QUESTION 7. How would you allocate the cost between oil and gas production with the facilities which would be either owned by the pipeline or jointly with your company? Please explain your rationale for such allocation.

ANSWER 7. We do not anticipate the joint ownership by a pipeline company and Atlantic Richfield of any facility handling oil and gas production.[4/] If we were to utilize any facilities owned by the pipeline for such purpose, we would expect to negotiate a charge for such use.

QUESTION 8. If the Prudhoe Bay gas is to be processed through facilities owned by the pipeline or jointly by the producer, who will have benefit of the liquid products and how will the operation and maintenance costs be allocated and on what basis?

ANSWER 8. If your word "processed" is intended to mean conditioned or treated, then under the present argreements[5/] on our Prudhoe Bay gas, Atlantic

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4/ See Answer I, 6.

5/ See Answer I, 2.

Richfield would have the option to take in kind any liquid hydrocarbons incidentally recovered therein. Details were never negotiated but, since it was contemplated that the gas would be sold on a BTU basis the purchaser would have been compensated for the heating value of any liquids extracted and redelivered to the producer.

QUESTION 9. Provide the (a) length and size of the gathering facilities for your operation, (b) estimated cost of such line, (c) ownership of such lines, and for those lines to be owned by the pipeline purchaser or jointly with the producer how will costs be allocated for that portion of the facilities attributable to the transportation of gas?

ANSWER 9. (a) Assuming that your question pertains to natural gas gathering facilities, the natural gas gathering facilities consist of lines connecting the six separation centers to a conditioning facility. These lines are expected to be as follows: 30" diameter, 7 miles; 34" diameter, 5-1/2 miles; 38" diameter, 5-3/4 miles; 42" diameter, 5-1/2 miles. These data are for the entire field.

(b) The cost for these lines is currently estimated to be slightly in excess of

$60 million.

(c) See Answer to I, 6.

QUESTION 10. What type of design would be required for the gas gathering system, i.e., buried, above group pipe, chilling facilities, etc.?

ANSWER 10. The gathering system will be installed on supports above ground and insulated.

QUESTION 11. Would your cost estimates vary depending upon whether the Arctic Gas or El Paso project were certificated?

ANSWER 11. No. We assume that the pipeline delivery specifications, both as to gas quality and pressure, would be identical for either project.

QUESTION 12. What percentage of gas available at the wellhead will be lost in treatment and/or processing?

ANSWER 12. We anticipate that approximately 6% of the hydrocarbon gas could be consumed in conditioning the gas to pipeline requirements. This estimate does not include fuel for operation of the Prudhoe Bay Field.

QUESTION 13. What state approvals will have to be obtained in relation to Alaskan North Slope gas production and when will your company make the necessary filings to obtain such approvals?

ANSWER 13. The lease owners of the Prudhoe Bay Field are actively engaged in discussions to

unitize the field. The Prudhoe Bay Field should be unitized prior to commencement of oil production and the agreement must be approved by the Alaska Oil and Gas Conservation Committee. The unitization agreement should contain a plan for the development and operation of the Prudhoe Bay Field, including gas sales timing and volumes, as well as facilities, wells and liquid production rates. The Prudhoe Bay Field owners expect to request approval of these documents during the last half of 1976.

Respectfully submitted,

ATLANTIC RICHFIELD COMPANY

By P. T. Davis ERL

P. T. Davis

AFFIDAVIT

DISTRICT OF COLUMBIA)

EDWARD R. LEAHY, being duly sworn, deposes and says that he is an attorney for Atlantic Richfield Company; that he is authorized to verify and file this document; that he has examined the statements contained in the submittal and that all such statements are true and correct to the best of his knowledge, information and belief.

Edward R. Leahy
EDWARD R. LEAHY

Subscribed and sworn to before me this 13th day of February, 1976.

Sandra M Pagac
NOTARY PUBLIC

(SEAL) My Commission Expires: August 15, 1977

AGO 545378