

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

1036 SCOMM 28: JOINT GAS PIPELINE COMMITTEE, 1981-82

opinion, there is a greater likelihood that any unforeseen change in future prices will be in an upward rather than a downward direction, and a percentage premium would thus be advantageous to the state.

(6) Paragraph 9: Security

This provision, which establishes a fixed security bond per lot, would, as paragraph 2 does, act to discriminate against possible small bidders. Although foregoing a large security may increase somewhat the risks to the state, it would have the effect of serving other goals of the state, such as encouraging small business. The ability of a small buyer to fulfill its obligations of the contract could better be judged under the detailed specific provisions of paragraph 11, "Qualifications of Bidders".

A more equitable arrangement would be to tie the amount of bond to the quantity of oil bid on. A small buyer, bidding on several hundred barrels would pay a much smaller bond than a buyer bidding for 10,000 or 20,000 barrels.

7. Conclusions

In conclusion, we would recommend the following changes in the invitation to bid:

Paragraph 2, Lots: Allowing buyers to bid on exactly the amount of crude they need rather than on the proposed 17 lots of about 5,000 b/d each.

Paragraph 3, Term: Keeping the term of the auction contract for one year, but eliminating the provision allowing bidders to cancel their contract.

Paragraph 6, Price: The state should closely examine the possibility of the auction displacing North Slope producers' oil from the West to Gulf Coast and lowering the average wellhead price. It should consider establishing the minimum bid price as the in value reported price of the oil at the time of delivery plus a dollar amount which would offset any estimated possible state loss from a lowered wellhead value.

Paragraph 7, Premium: A percentage premium, equal to a percentage of the in value price at the time of delivery, should be used, rather than a flat dollar and cents premium.

Paragraph 9, Security: The amount of security should not be a flat amount, but should be tied to the quantity of oil for which a bid is made.

FOOTNOTES

1. Business Week, October 6, 1980, p. 36.
2. Oil and Gas Journal, April 21, 1980, p. 28.
3. Transport cost differential between the West and Eastern Coasts from, Department of Energy, Economic Regulatory Administration, "Alaska North Slope Entitlements Adjustment" (Washington, D.C., U.S. Department of Energy, September 12, 1980) p. 8.
4. Calculation of transport differential's effect on average weighted price of oil is based on formula in "Exhibit B, Alaska Petrochemical Company: Alaska Royalty Crude Oil Contract" February 22, 1978, pps. B-1, B-2.
5. Bids for Elk Hills from Oil and Gas Journal December 31, 1979, p. 54.
6. Teapot Dome data from Oil and Gas Journal January 21, 1980, p. 53.
7. Tanzer Economic Associates, Inc., "The Beaufort Sea Oil Lease Sale: A Comparative Analysis of Different Bidding Systems." (A Report to the Alaska State Legislature) January 4, 1980, pps. 12-13.

Footnotes, continued

8. Oil and Gas Journal, December 31, 1979, p. 54.
9. Platt's Oilgram News, March 28, 1980, p. 2.
10. U.S. Department of Energy, Naval Petroleum Reserves in California, "Invitation for Bids for the Competitive Sale of Crude Oil from Naval Petroleum Reserves No. 1 and 2. Kern County, California" (IFB No. DE - FBO1 - 80RA 32119) (Washington, D.C., U.S. D.O.E., October 21, 1980) p. 34.

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Withow

A CURRENT PERSPECTIVE ON
USE OF NATURAL GAS LIQUIDS
FOR
PETROCHEMICAL PRODUCTION IN ALASKA

10 January 1979

Prepared for
Royalty Oil and Gas Development Advisory Board
State of Alaska

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SUMMARY

Bonner & Moore has prepared an overview of the current situation as regards the prospective development of a petrochemical industry in Alaska based on the use of natural gas liquids produced at Prudhoe Bay.

At the present time, the prospects of selling Prudhoe Bay gas at regulated ceiling prices appear to be dimming. While this is an unwelcome development for Alaska, in that it reduces the royalty value of North Slope gas production, it enhances the prospect that the alternate value of these materials as petrochemical feedstocks will become their most economic disposition and therefore provide the greatest benefit to the state.

Regulatory delays, high transportation costs, and a generally negative perception of the business climate in Alaska have resulted in an impasse over the matter of gas production and sale. The prospects of catalyzing industrial leadership in the use of gas liquids in-state are poor for these reasons. A thoughtful consideration of alternatives has led Bonner & Moore to a reluctant but firm conclusion that only a commitment by the state to lead these activities can significantly enhance the prospects of in-state petrochemical development.

We recommend that a legislative proposal be prepared to authorize the following activities:

- 1) The design and firm cost estimation of a gas liquids line from Prudhoe Bay through Fairbanks to Kenai.

- 2) The development of plans for state financing.
- 3) Preparation of a recommendation for state or private financing.
- 4) Development of plans for state financial participation in an operating company (should that option be recommended) and solicitation of business from producers and prospective purchasers of gas liquids.

Evaluating the use of gas liquids for in-state petrochemical manufacture requires that realistic alternate values of gas liquids be clearly understood so that their net value to the state can be maximized. The value of gas liquids for petrochemical feedstocks is at least 30 percent lower at a tidewater Alaskan plant site than if the same material were available to a comparable plant on the U.S. Gulf Coast. The wellhead value is further reduced in Alaska by the high cost of transportation.

If Prudhoe Bay gas can realize the regulated gas ceiling price (currently \$1.63/MMBTU) at the wellhead, its greatest direct revenue benefit to the state will be for interstate pipeline sales. If the wellhead value is reduced from the ceiling price by deduction of conditioning and compression costs the greatest net benefit to the state from the gas liquids may well be as petrochemical feed and LPG sales although the precision of current data are not adequate to make this distinction. If the wellhead value is determined by free market forces in the lower 48 states, the greatest net benefit derivable from the gas liquids will be from in-state recovery and use.

It is Bonner & Moore's opinion that the various uncertainties surrounding the Alaska gas pipeline will be resolved unfavorably and that in-state use of gas liquids will provide the greatest net benefit to the state.

This opinion plus the anticipated prolongation of regulatory proceedings relative to the whole matter of the gas pipeline leads us to the recommended course of action. This is the only approach we can see that will enable the state to influence events favorably toward petrochemical industry development.

Furthermore, recent OPEC increases in crude oil prices, coupled with continuing control of U.S. gas prices is a favorable development with regard to making in-state petrochemical use of gas liquids more economically attractive relative to their pipeline sale or use as fuel at Prudhoe Bay.

FURTHER DISCUSSION OF BONNER & MOORE'S
PRIOR ROYALTY GAS STUDY

The earlier Bonner & Moore study of royalty gas utilization developed some values of ethane for petrochemical use. The values were a function of presumed petrochemical product prices, the costs of manufacture, and the cost of transportation. That study considered many options of geography and quantities of recovered ethane plus associated gas liquids.

The most favorable case examined, namely the case that produced the highest ethane value, determined a value of \$1.24/million BTUs at Prudhoe Bay. Since completion of that study other considerations have directed interest primarily toward the case where gas liquids are recovered at Prudhoe Bay and pipelined to a tidewater location.

Using data from the earlier report, gas liquids recovered and used as petrochemical feedstocks would incur the following costs:

Recovery of C ₂ + liquids at Prudhoe Bay	\$1.08/Bbl
Pipeline Transportations to Kenai area	<u>\$2.23/Bbl</u>
Total Recovery and Transportation Cost	\$3.31/Bbl
or @ 3.053 MMBTU/Bbl	\$1.08/MMBTU

The feedstock value calculated from petrochemical prices and manufacturing costs is \$2.10/MMBTU. Subtracting the costs of \$1.08/MMBTU from this value yields a value at Prudhoe Bay of \$1.02/MMBTU. This petrochemical value must be

compared to the fuel value to determine which use value is the higher. If the gas liquids are to be used for petrochemical feedstock, then they must command the higher value in that use.

This petrochemical value of roughly \$1/MMBTU at Prudhoe Bay must be compared to the BTU value of hydrocarbons transported to the lower 48 states through the proposed Alaska Gas Pipeline.

Under provisions of the Natural Gas Policy Act of 1978, Prudhoe Bay gas would have a current regulated ceiling price of \$1.63/MMBTU. It is unknown, at present, whether this price will be allowed for any gas at the wellhead or only for gas meeting the following standards:

Total Sulfur (gr./100 cf.)	20 maximum
Hydrogen Sulfide (gr./100 cf.)	1 maximum
Water (lb/MMCF)	7 maximum
Carbon Dioxide (volume percent)	3 maximum
Other impurities requiring the buyer to incur costs to meet pipeline requirements	

It would appear that proposed regulations for gas pricing, as they might affect Prudhoe Bay production, will be determined by special review of FERC (Federal Energy Regulatory Commission). The specific issue is whether the ceiling gas price would be *increased* by the cost of "gas conditioning" at Prudhoe Bay or whether those costs would be *included* in the ceiling gas price.

To illustrate how this determination could affect the alternate fuel value of Alaskan gas liquids, consider the following scenarios.

Scenario 1

Prudhoe Bay gas is allowed a regulated price of \$1.63/MMBTU plus the cost of gas conditioning and the gas is successfully sold at this price.

Scenario 2

Prudhoe Bay gas is allowed a regulated price of \$1.63/MMBTU but no added allowance is made for gas conditioning cost.

Scenario 3

Prudhoe Bay gas can be sold only at a market clearing price in competition with other gas supplies available to purchasers in the lower 48 states.

The cost of gas conditioning has not been developed to the same degree as the costs associated with pipeline operation. However, based on a preliminary study of gas conditioning made by Ralph M. Parsons Inc., it could be expected that conditioning costs in the range of \$0.50 to \$1.00 per MMBTU would be incurred. For subsequent use in our analysis a figure of \$0.75/MMBTU will be used for the cost of gas conditioning including compression to pipeline pressure. With such a figure, the three scenarios can be examined to see what circumstances will lead to the use of gas liquids for in-state petrochemical development.

<u>Scenario</u>	<u>Pipeline Value of Gas Liquids at Current Price Levels (\$/MMBTU)</u>	<u>Prospects for In-State Petrochem- ical Use of Gas Liquids</u>
1	1.63	None
2	0.88 (est.)	Feasible
3	Nominal	Good
Petrochemical Value	1.00 (est.)	

In scenario 3 it is unlikely that the Alaska gas line would be built, at least in the foreseeable future. In such a case, the producers could well make a concerted effort to recover and sell gas liquids from Prudhoe Bay, reinjecting only a lean gas stream back into the reservoirs.

In scenario 2 the alternative of selling gas liquids would probably be given serious consideration and improved cost estimates prepared. State assistance could make an important difference, in this case, as to whether or not in-state use or sale would be pursued by the producers.

The determination of which scenario will prevail must first await the final regulations on gas pricing to be adopted by FERC. Even these regulations will not completely define the gas pipeline's future because the entire gas project has not met the test of market acceptance. In the view of Bonner & Moore, the gas pipeline project, or at least the Alaskan portion, is not economically sound. Only substantial government subsidization or favorable regulatory bias toward the project will enable its realization. Probably another 12 months will elapse before the alternate values of Prudhoe Bay gas can be forecast with accuracy.

STATE PARTICIPATION IN DEVELOPMENT OF
GAS LIQUIDS BASED INDUSTRY

The three most important obstacles to positive action by private industry to develop an Alaska-based petrochemical industry are:

- 1) continuing uncertainty in Federal regulatory policies,
- 2) high cost of bringing feedstocks to the south coast of Alaska, and
- 3) a suspicion that Alaska will not provide a hospitable regulatory or economic climate for large industrial concerns.

The state can alleviate (although not eliminate) all these obstacles by a forthright recognition of the special problems facing Alaskan development and committing to a program that materially improves the economic climate.

In the specific case of gas liquids utilization, this probably means that the state should seriously evaluate the financing and encourage development of a pipeline system to bring gas liquids from Prudhoe Bay to tidewater. If such a project were developed and approved for implementation by the state, subject to appropriate utilization contracts, serious competition for the use of gas liquids should follow.

The state can offer two advantages in this role. One is positive leadership. The second is more favorable financing terms that could reduce the calculated transportation and processing cost of \$1.10/MMBTU for gas liquids by, perhaps, 15-20 percent.

The state can take other steps that would be complimentary to a program for building the necessary pipeline system. These would include the development of streamlined permitting procedures and the compilation of data pertinent to the costs of operating a petrochemical enterprise in Alaska.

Bonner & Moore's recommendation is that the state immediately embark on a two-pronged program aimed at determining the feasibility of a state-financed pipeline project for transporting natural gas liquids from Prudhoe Bay through Fairbanks on to the Kenai Peninsula.

One activity would be the design and cost estimation for the line. The second activity would be to investigate financing alternatives and prepare cost projections for operation of the system.

This program might result in either a state-financed operating enterprise or in private interests becoming involved as the project grew more clearly defined.

The principal expense would be the design and cost estimate for the line. This would be a major item and would require a special appropriation. An estimate of this cost is being prepared and will be supplied within a few days.

The program for promoting petrochemical industry development that has been proposed by the Royalty Board seems completely appropriate to a situation where a course of action is to be influenced. At the present time, however, the state is confronted by inaction.

In our opinion the state faces two choices in pursuit of petrochemical industry development. It can lead or it can follow. This presumes that a third choice of opposition is null. Since there is clearly a leadership vacuum, and may well continue to be, the Royalty Board should prepare a legislative proposal for state leadership in building the key pipeline component of a system to use gas liquids in-state.

Such action goes beyond studies and positively furthers the prospect of actual development. The risk can be confined to the cost of engineering design and cost estimation plus perhaps 30 percent additional cost for ancillary activities.

More accurate investment figures and financing studies may disclose that the construction and operation of a gas liquids pipeline is a proper private investment. It may also show that transportation costs can be kept to adequately low levels only if the enterprise benefits from low cost financing and tax exemption through state participation.

The Royalty Board should sponsor development of these alternatives and recommend the form of enterprise to build and operate a pipeline. At that time offers for the use of the pipeline and for use of the states' Royalty Gas liquids (possibly augmented by BTU equivalent swaps of liquids for lean gas) can be solicited with good prospects for constructive responses.

BACKGROUND: Forecasts of Petrochemical Feedstock Values and Comparisons Between LPG, Naphtha, and Gas Oil for the Production of Ethylene

Ethylene is the world's major petrochemical product. Ethylene is used in the production of other materials and is purely an intermediate material. Plastics and anti-freeze are the two largest volume derivatives of ethylene.

Ethylene, and a similar material propylene, were first produced in large quantities from ethane and LPG (propane and butane). The historically low price of natural gas relative to crude oil and the simpler technology required to "crack" ethane and LPG to ethylene made these materials the preferred feedstocks for U.S. ethylene plants.

In Europe and Japan there has been no natural gas industry or gas liquids imports until recent years, and so ethane and LPG were not available as large volume feedstocks for ethylene manufacture. Consequently, technology was developed to produce ethylene and other olefins in those areas from hydrocarbons heavier than LPG, primarily naphtha.

Rising natural gas prices and prospective shortages of ethane have caused the construction of new ethylene producing capacity in the U.S. that utilizes naphtha and even heavier materials such as gas oil for feedstocks. Since technology exists to use these heavier feedstocks that derive from crude oil, their cost serves as a stable reference point against which other feedstocks can be compared.

If we examine the trends in prices for crude oil and natural gas, including the price-related ethane and LPG materials, we can see how the petrochemical value of natural gas liquids will compare with their price fuel or BTU value. In this analysis, the general case for the lower 48 states is considered. The special circumstances pertaining to Alaska can then be considered and some fairly specific conclusions drawn.

Crude Oil Pricing

Crude oil production for the U.S. should peak near 1990. The rise from today's production through that period will result from the inclusion of Alaskan crude oil and new offshore production which will offset the current and continuing decline of production in the contiguous 48 states.

Crude oil demand will continue to rise steadily through 1990 and then begin to slow its rate of ascent. Crude demand, however, will increase faster than production rate increases and the U.S. will be importing an ever-increasing percentage of its crude oil requirement.

Bonner & Moore's projection of domestic production, foreign imports and total demand for crude oil is illustrated in Figure 1.

We do not expect that crude oil price increases will be uniform or capable of being "programmed". Rather, they will most likely come as a result of supply and demand forces interacting with steep increases in years of strong economic recovery followed by declining real-dollar pricing for several years thereafter.

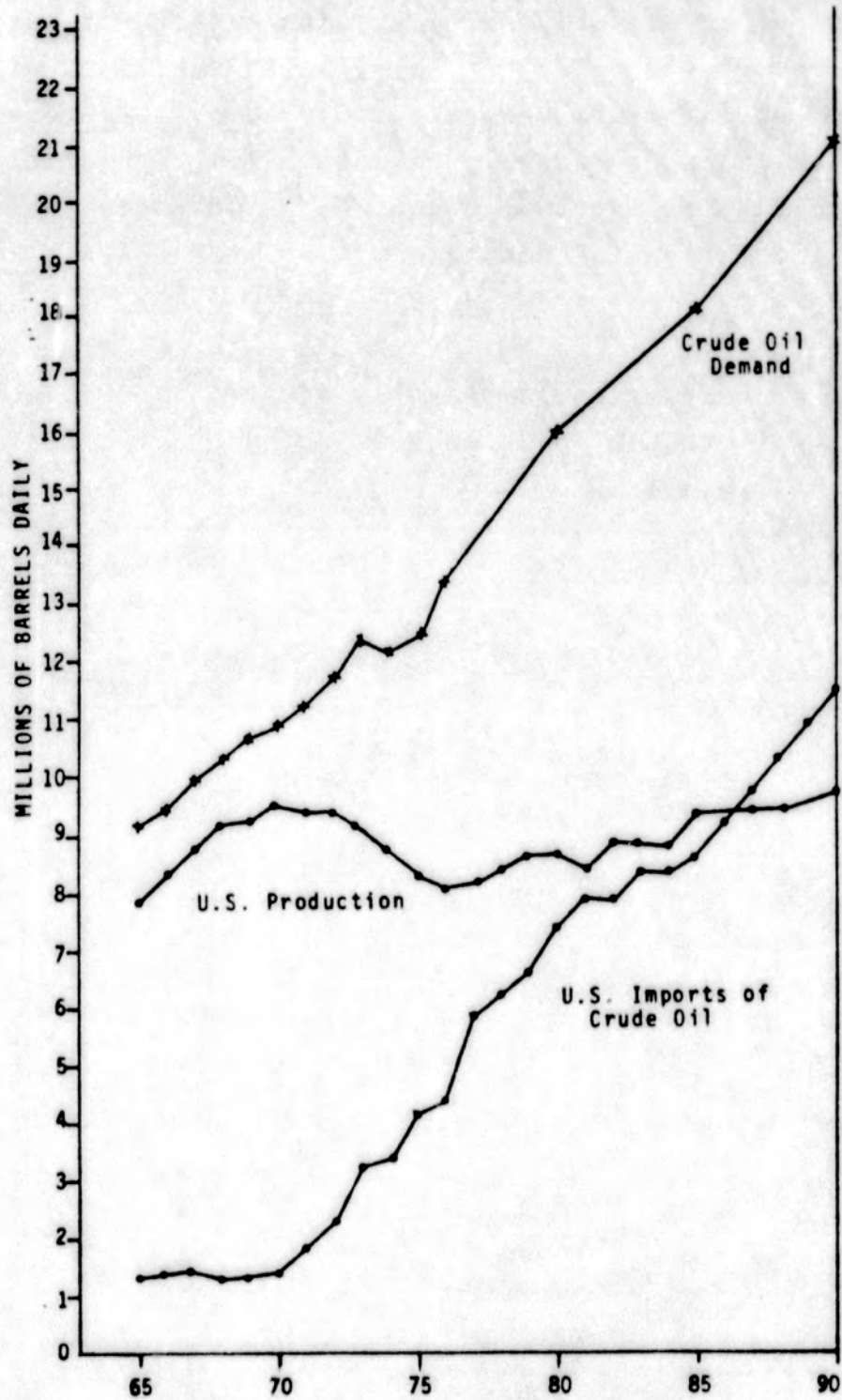


Figure 1. Crude Oil Supply & Demand
(MMB/D)

Major energy legislation which succeeds in the development of a rational energy pricing pattern is not likely to occur before 1980. Any plan so developed will follow the regulatory framework envisioned by the present energy legislation on natural gas with multi-tier pricing levels resulting in eventual decontrol. Such decontrol is expected to occur in the vicinity of 1990 rather than in the 1980 area.

The demand projection--plus identified pricing influences will result in average U.S. crude oil costs as reflected in Table 1.

TABLE 1
U.S. GULF COAST CRUDE OIL PRICE FORECAST
1970-1990
(Current Dollars)

YEARS	\$/BARREL	\$/MMBTU
1970	3.25	0.59
1975	10.28	1.85
1980	13.42	2.42
1985	20.50	3.65
1990	31.50	5.68

Light Gas Oil (No. 2 Fuel Oil)

The pricing of No. 2 fuel oil is primarily a function of crude oil acquisition costs. Although No. 2 fuel oil prices will vary as a function of capital costs, operating expenses and the condition of the fuels market, prices can be expected to vary between 11 and 14 percent above crude oil prices over the foreseeable future. Using factors developed in a 1975 Bonner & Moore study for the Department of Transportation, the price for No. 2 fuel oil (at the refinery gate) is projected as shown in Table 2.

TABLE 2

U.S. GULF COAST PRICE PROJECTION FOR NO. 2 FUEL OIL
(Current Dollars)

YEARS	\$/BARREL	\$/MMBTU
1970	4.27	0.73
1975	11.59	1.98
1980	15.37	2.63
1985	22.88	3.91
1990	35.60	6.08

Natural Gas Pricing

Natural gas pricing bears little resemblance to rational supply/demand relationships. The events of the past 18 months have shown natural gas pricing to be both volatile and politically sensitive. From past analyses, we could expect natural gas to maintain a 20 percent or higher price premium in an unregulated market due to its environmentally superior nature. However, many industrial markets will likely be closed to the use of natural gas by federal and state restrictions.

Further, the Natural Gas Act of 1978 appears to have set the pattern for gas pricing during the next 5 to 10 years. This pattern suggests that natural gas price at the wellhead will:

- 1) Continue to be controlled,
- 2) Have a maximum price equal to replacement cost with No. 2 fuel oil, and
- 3) Have a price based on "vintage" categories which will impact each region, company and consuming group differently.

To understand the magnitude of the price variations authorized by the Natural Gas Act of 1978, the wellhead ceiling prices for several categories of natural gas are presented in Figure 2. These prices are shown as they would be computed if gas deregulation does not occur and controls are extended to 1990. Additionally, our projection of No. 2 fuel oil price at the refinery gate (U.S. Gulf Coast) is shown for comparative purposes. It is seen that natural gas priced equivalent to No. 2 fuel oil would violate the ceiling price by 12 percent.

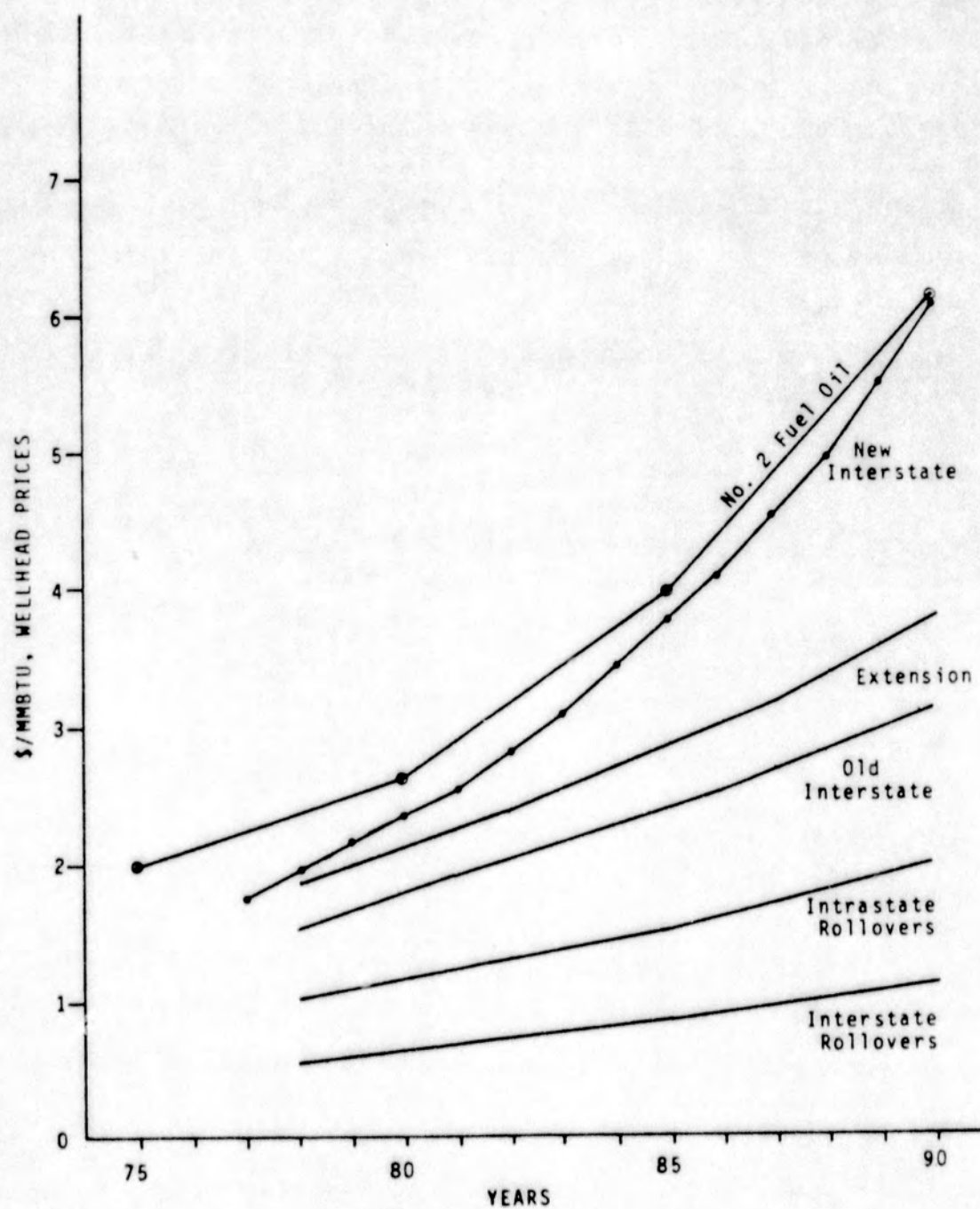


Figure 2. Possible Ceiling Prices For Natural Gas Under Senate-House Compromise Provisions (Excludes Severance Tax)

If natural gas were priced at 120 percent of the price for No. 2 fuel oil, the violation would be by 32 percent. We must, then, conclude that natural gas will be priced at or below No. 2 fuel oil for the years 1978 to 1990--even though many industrial consumers could afford to pay 20 percent or more above the price for No. 2 fuel oil for natural gas because of environmental, current logistical and structural considerations.

Pricing of Ethane and LPG

The forecasting of Ethane and LPG pricing requires a complex mechanism which includes the selection of the pricing basis by which the value of each component (ethane, propane, butane and C5-and-heavier) will be determined. It is expected that the pricing bases for some or all of these components will change over time.

For example, consider two situations under which pricing is computed.

First, assume that natural gas at the wellhead is priced so that, on balance, it is below the cost of No. 2 fuel oil when it reaches its ultimate consumer. This was the situation existing prior to the 1973 oil embargo. The extraction of LPGs from the gas stream, if the extracted products were valued at competitive fuel prices equivalent to No. 2 fuel oil, represents an upgrading of the value of the natural gas stream. In 1970, for instance, fuel oil sold for 73 cents/MMBTU, natural gas sold for 22 cents/MMBTU and propane sold for 69 cents/MMBTU. By extracting propane, the seller of natural gas could leverage his natural gas value by obtaining a product in a more easily transportable form which could

bear a much higher final sales price. Further, propane was not regulated and the profit from its sale was not included in the rate base. The cost base at the extraction plant was its fuel value as natural gas--not its value in the regulated market place. The important point is this: *The liquids from a natural gas stream sold for a market value far in excess of the regulated natural gas price, and this "upgrading" process was profitable even considering the operating and capital costs connected with extraction of liquids from the natural gas stream.*

Now, as a second situation, assume that natural gas is priced as a "fuel" in its own right--having a value nearly equal or above that of a competing fuel, No. 2 fuel oil. At this juncture, what was "upgrading" in the first situation reverses to a "downgrading". *The extraction of liquids incurs costs which raises the cost base for the liquids while creating a product which sells for approximately the same price as the initial feed--natural gas.* In our analysis, the point at which the "upgrading" turns to "downgrading" is when natural gas reaches approximately 64 percent of the price for No.2 fuel oil.

Earlier it was stated that natural gas is fairly priced in the market place when natural gas at the wellhead in the present gas producing areas reaches 80 to 120 percent of the price for No. 2 fuel oil on the Texas Gulf Coast. In the foregoing paragraph, we stated that natural gas liquids extraction is attractive only when natural gas is priced at less than 64 percent of the price for No. 2 fuel oil and that extraction is affected negatively when the price for natural gas exceeds that level. Clearly, our projections imply that liquids extraction will be negatively affected and thus, that the price of some or all of the component LPGs will have to sell above their BTU value if new extraction plants are to earn a fair return on invested capital.

Extraction Costs

The cost of extracting LPGs is dependent on the cost of the feed to a natural gas extraction plant, the fixed expenses (manpower, maintenance, etc.), the variable expenses and the revenues to recoup the investment and provide a return on that investment. These components of extraction cost should be spread over the sum of products recovered and the total dollars of revenue received should equal or exceed the costs. The bases we used to allocate the total cost is the weight basis fraction which each component recovered has in the final product mix.

Figures 3 and 4 show the results of our calculation of costs, on a weight basis, for ethane and propane. Further, the value of each stream is shown at its heating value if ethane and propane sold at the then existing No. 2 fuel oil price on the Texas Gulf Coast. Note that costs are shown with and without capital recovery, demonstrating the range within which prices may fall, based on recovery of fixed plus variable charges (w/o CR) and with full recovery of profit plus depreciation (w/CR). The difference between the two represents the leeway which the extraction plant has to lower prices during periods of slack demand.

If we assume that the general market for propane is for heating and that no substantial price differential will exist for environmental reasons (which is consistent with the 80 percent value of natural gas relative to No. 2 fuel oil) then it is clear that the value of propane, over time, will be below the cost of its extraction. We can forecast this in light of our comments regarding the breakpoint of 64 percent for natural gas pricing relative to No. 2 fuel oil.

To clarify the likely price decisions which will be made, it is necessary to define the alternate values which exist--that is, values based on something other than fuel-based value or value based on extraction cost.

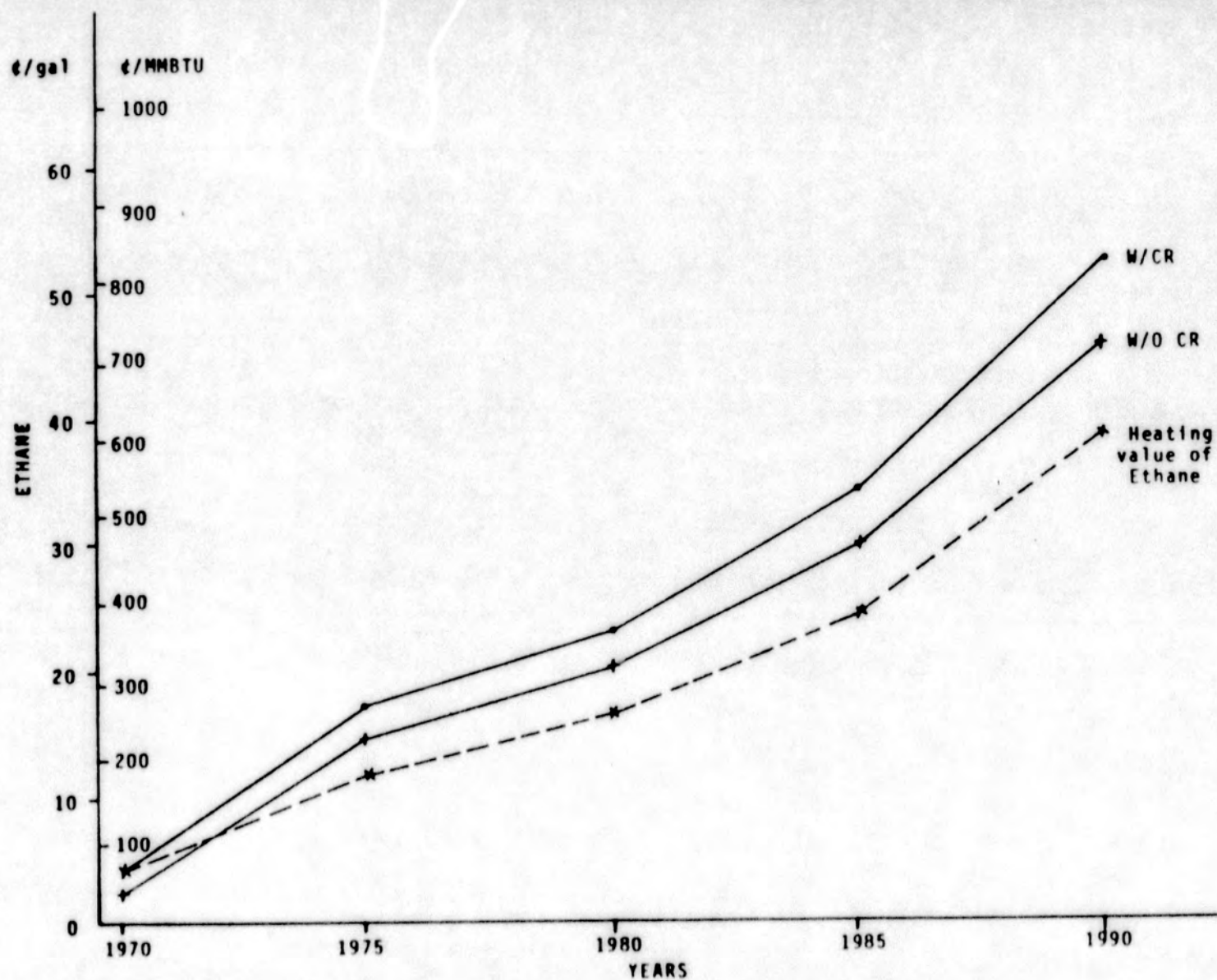


Figure 3. Cost of Extraction Basis--Ethane

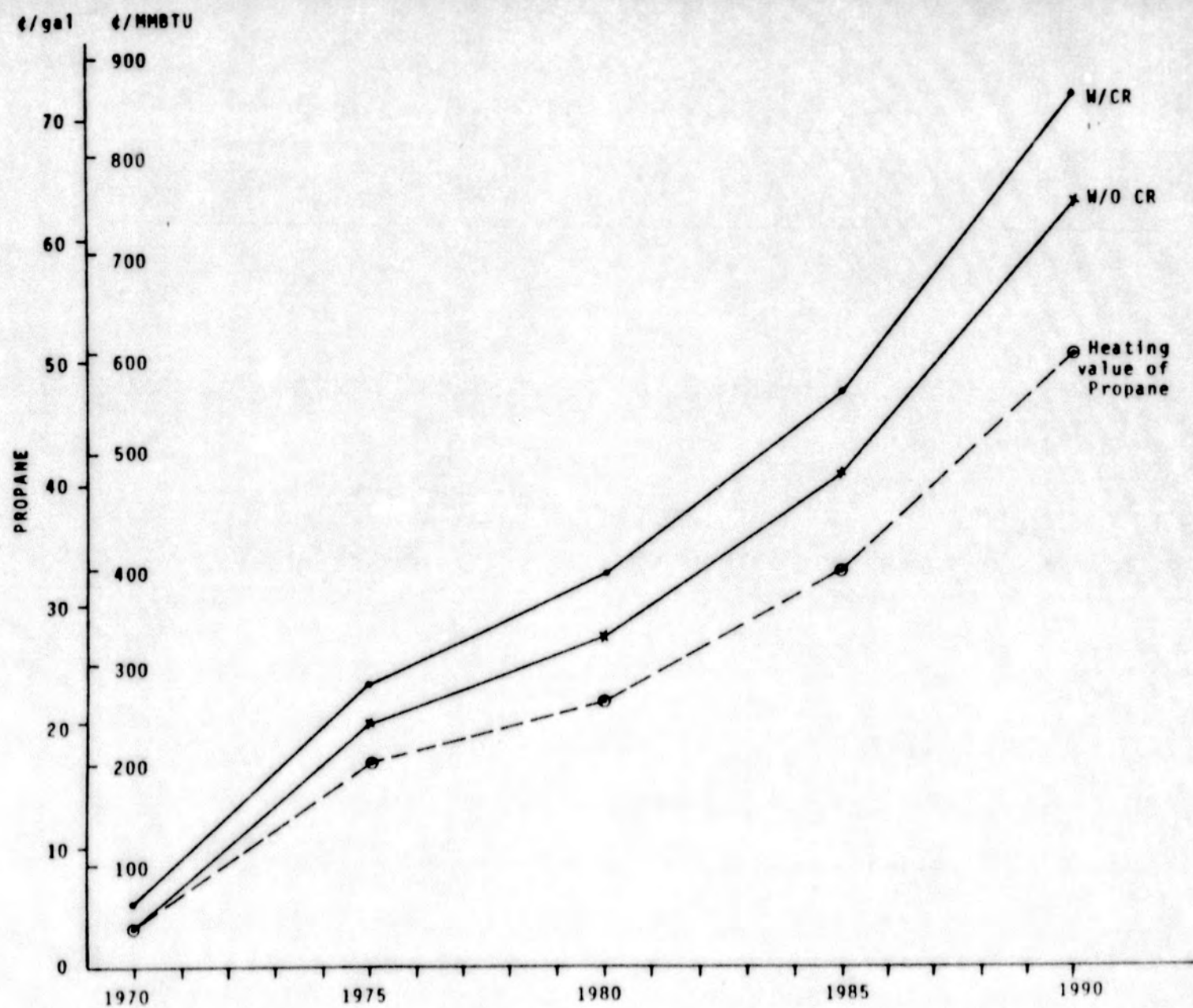


Figure 4. Cost of Extraction Basis--Propane

Alternate Values

The paragraphs in this subsection explore the alternate values for each component natural gas liquid.

Alternate Value for Butanes and C5 and Heavier

The highest alternate value for Butanes and C5 and heavier components are as refinery feedstocks. Based on a study performed for the Department of Transportation in 1975, we forecast the following values:

YEARS	ALTERNATE VALUES (Cents/Gallon)	
	<u>Butanes</u>	<u>C5 and Heavier</u>
1975	18.98	22.74
1980	26.17	29.93
1985	45.17	47.79
1990	61.60	71.31

Although the ratio of product price to crude oil price might vary under the specific assumptions used in this study, the 1975 study which we utilized is sufficient for these projections. The above prices are for the U.S. Gulf Coast.

Butanes and C5 and heavier components have limited use in petrochemicals. However, we expect during the time period under investigation, that the controlling alternate value will be as feedstocks in refineries.

Ethane and Propane Alternate Values

Propane's alternate value, other than as a fuel, will be determined by the price which the market is willing to pay for ethylene, i.e., propane's alternate value in petrochemicals. To calculate this value, we must first look to the petrochemical industry to see what feedstocks are being most frequently used. Ethylene units built since 1970 have been predominately of the "liquid feed" type using naphtha or more frequently light gas oil as feedstock.

In Figure 5 the required sales price for ethylene is shown with parameters of feedstock, and whether from new or existing plants. This figure shows that relative feedstock costs caused gas oil to become the preferred feedstock for new ethylene plants in 1976. Since that time ethane has become progressively less favorable in the general case. Special considerations, such as limited markets for the many by-products of gas oil cracking still cause ethane feed plants to be given serious consideration when adequate ethane supplies are available. One such plant is presently under construction by Phillips Petroleum Company.

Nevertheless it is evident from Figure 5 that new steam crackers using ethane as a feedstock will not be generally economic on the Gulf Coast while, at the same time, steam crackers which already use ethane as a feed will remain competitive. Using the minimum price for ethylene and allowing full capital recovery for new plant capacity (1970 and 1975 are ethane-based while 1980 to 1990 are gas oil-based), we can impute the maximum price which a petrochemical manufacturer would pay for propane in these years.

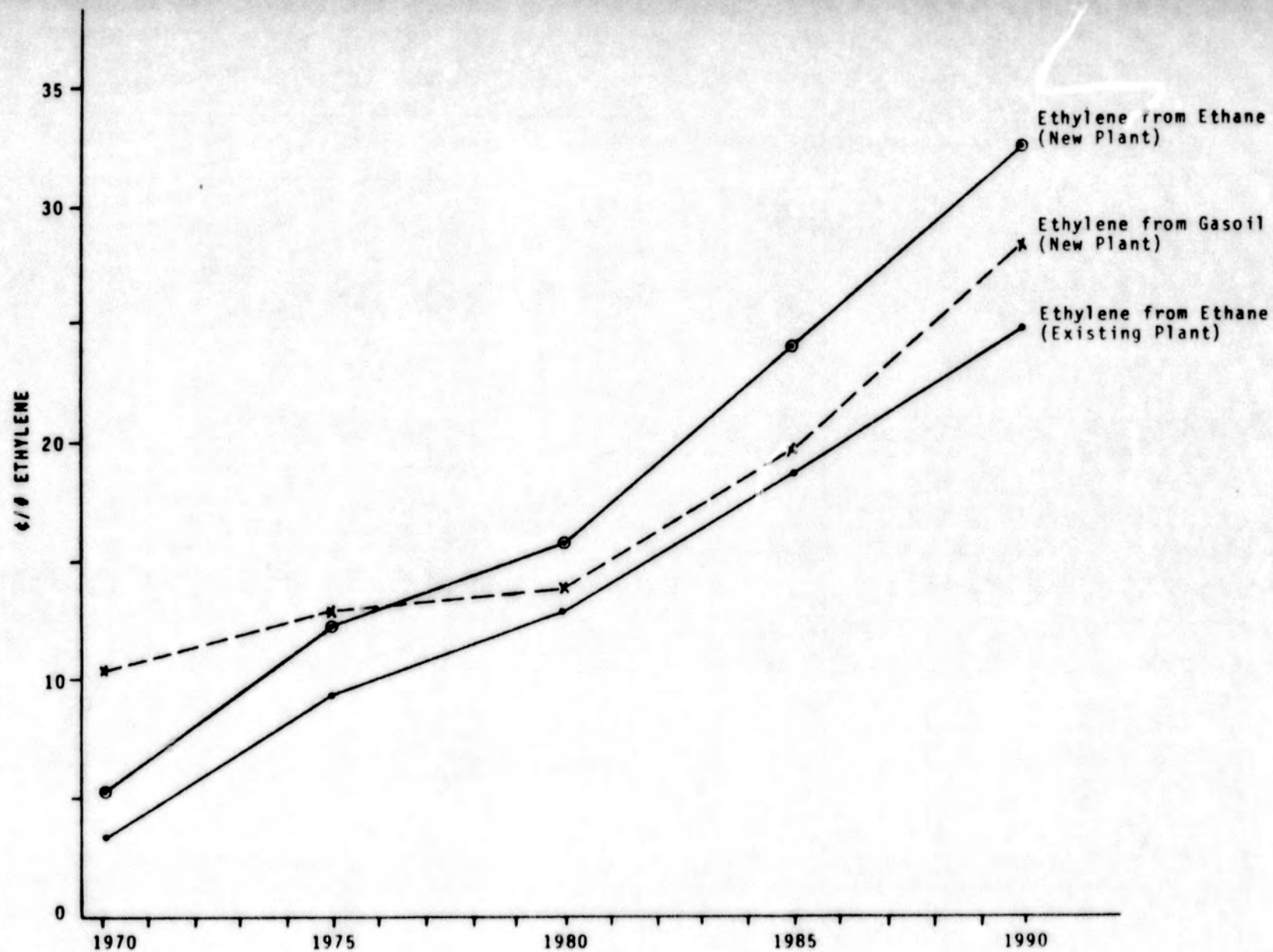


Figure 5. Ethylene from Ethane and Gasoil

Table 3 summarizes the cost of LPG extracted from "new" natural gas and the values of each product is their best alternate use to fuel. Clearly the future value of "new" gas will be too high for the extraction of gas liquids to be generally economical.

TABLE 3
DIFFERENTIAL BETWEEN COST AND ALTERNATE VALUE
AS SEGREGATED MATERIAL
(¢/gal)

	<u>1975</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>
<u>Propane</u>				
Fuel Value plus Extraction Costs	23.70	32.36	47.44	72.14
Alternate Value	<u>22.44</u>	<u>26.98</u>	<u>38.42</u>	<u>55.46</u>
Difference	1.26	5.38	9.03	16.68
<u>Butane</u>				
Fuel Value plus Extraction Costs	27.23	37.18	54.50	82.89
Alternate Value	<u>18.98</u>	<u>26.17</u>	<u>45.17</u>	<u>61.60</u>
Difference	8.25	11.01	9.33	21.29
<u>C5 and Heavier</u>				
Fuel Value plus Extraction Costs	30.95	42.25	61.92	94.20
Alternate Value	<u>22.74</u>	<u>29.93</u>	<u>47.79</u>	<u>71.31</u>
Difference	8.21	12.32	14.13	22.89

BACKGROUND: Factors Affecting NGL Values
in Alaska

We contemplate that Alaska will experience somewhat different economic conditions affecting the value of natural gas and gas liquids. The cost of transporting Alaska's hydrocarbons to market is extraordinarily high. The values of hydrocarbons for in-state use are distorted by this cost in comparison to values in the major U.S. petrochemical producing areas.

The state is familiar with this distortion of values from the experience of having its crude oil royalties substantially reduced when Alaskan crude must be transported to Gulf Coast refineries. In round figures, the wellhead value of Prudhoe Bay crude oil is 60 percent of its average delivered U.S. refinery value. If the gas pipeline were to be built and the regulated wellhead price of \$1.63/MMBTU were realized by the producers, this would represent only about 30 percent of the market price to distributors in the lower 48 states. If marketplace economics were to prevail, rather than economics dictated by governmental regulation, then the wellhead value of Prudhoe Bay gas would be negative since the combined costs of conditioning and transportation are greater than the price of alternate gas supplies such as Mexican or Canadian gas.

The use of natural gas liquids for petrochemical manufacture in Alaska will be economically feasible only if these materials have an in-state value substantially lower than world prices. Some petrochemical cost figures will illustrate this point. Cracking of LPG at the U.S. Gulf Coast incurs a cost structure as shown in the following table.

<u>Cost Item</u>	<u>Percent of Total Cost</u>
LPG Feedstock Costs	46.4
Controllable Costs	23.6
Fixed Costs	5.7
Capital Recovery Costs	<u>24.2</u>
	100.0

If capital costs in Alaska must be escalated 40 percent over U.S. Gulf Coast costs, then the feedstock price must drop 21 percent to offset this escalation. If the proper escalation factor is 100 percent, then feedstock prices must drop 52 percent.

The Alaska location is removed from other U.S. markets for petrochemicals by a product transportation cost disadvantage of about 1-2 cents per pound. This amounts to around 4 percent of the revenue from potential petrochemical products such as plastics. If this adjustment were applied to the situation where Alaskan construction costs were shown to be 40 percent higher than U.S. Gulf Coast, the combined construction and product transportation cost effects would be to reduce LPG feedstock values by 30 percent. If the construction cost escalation factor were 100 percent, the LPG feedstock value would drop 61 percent.

The foregoing calculations apply to feedstock values at the plant site. In Alaska it is contemplated that separation and transportation costs from Prudhoe Bay to tidewater would amount to about \$1.10/MMBTU for natural gas liquids. In the earlier Bonner & Moore study on "Utilization of Royalty Gas" the value of ethane at a tidewater petrochemical plant site was \$2.10/MMBTU. That study used a capital cost escalation factor of 40 percent so we would deduce that the \$2.10

should be 70 percent of the "lower 48 value". This value would then calculate to \$3.00/MMBTU. Referring to the earlier Table 3 (page 21) we see that ethane priced at a "new gas" BTU value plus extraction costs is, indeed, \$3.00/MMBTU in 1978/79.

While these two independent determinations of ethane value should be essentially identical, this discussion may more readily illustrate the factors and their size magnitude that affect gas liquids values as petrochemical feedstocks in Alaska.

The most favorable economic circumstances for utilizing gas liquids in the state involve recovering and transporting the maximum quantity of these materials. This produces the most favorable economies of scale. However, even a very large initial petrochemical project in Alaska can consume only about 15-20 percent of the gas liquids that must be recovered if the logistics costs are to be kept to a feasibly low level. Therefore, 80-85 percent of the gas liquids must be sold in the LPG market. This volume of about 140,000 to 150,000 barrels per day is sufficiently large that no quick judgment can be made about the net market value of these materials in Alaska.

The earlier economic calculations assume that excess gas liquids, over petrochemical requirements, had the same value as ethane, namely \$2.10/MMBTU. Current LPG market prices suggest that this value is appropriate. However, the prospects for higher values in later years is reasonably good. The main question regarding LPG sales is how and whether a market can be found for this quantity of material.

Another occurrence that bears on the feasibility of petrochemical development in Alaska is the increase in world prices for petrochemical feeds. The recent OPEC crude price increase of 14.5 percent, by the end of 1979, plus continuing increases in domestic crude prices should add about \$0.40/MMBTU to ethane (and LPG) values as petrochemical feeds in 1980. Thus, the calculated Alaska tidewater value of \$2.10/MMBTU should increase to around \$2.50/MMBTU in that year.

MEMORANDUM

TO: [

DATE:

Charles R. Webber
Commissioner

FILE NO:

Thru: Richard H. Eakins, ^{TTE}Director TELEPHONE NO:
Division of Economic Enterprise

FROM: David M. Reaume, Principal Economist SUBJECT:
Division of Economic Enterprise *DMR*

Bonner and Moore Report
of January 10, 1979

On January 10, 1979 Bonner and Moore Associates, Incorporated, presented to the Alaska Royalty Oil and Gas Development Advisory Board a study of the economic feasibility of in-state processing of Prudhoe Bay gas liquids. The study's principal conclusion was that in-state processing might be economically feasible if the Alcan natural gas pipeline is not built, and if the State of Alaska takes steps to lower the costs of production to the processor. Bonner and Moore has recommended that a \$225,000 engineering cost study be done for one piece of the petrochemical project -- a proposed Prudhoe Bay to tidewater, eighteen inch, gas liquids pipeline. The Royalty Oil and Gas Advisory Board has concurred in this proposal.

I believe that Bonner and Moore's recommended study is premature and inadequately justified. My two primary reasons for believing this are:

- (1) Bonner and Moore's analysis is largely confined to one year, 1978. This may allow them to reach an overly optimistic conclusion as to the economic potential for in-state processing. In particular, in concentrating on present market conditions they appear to have completely ignored the Mexicans. Recently, the Mexican government has announced that it will offer a 30 percent discount on raw materials to encourage large scale petrochemical plant construction on both the Mexican Gulf Coast and the Mexican West Coast (Business Week, January 15, 1979). If they proceed, the market for basic petrochemicals such as ethylene and propylene may weaken further throughout the next decade.

- (2) Bonner and Moore's formal profitability calculations depend upon a capital cost for gas conditioning of \$310 million. While I have not attempted an independent estimate, I simply note that Bonner and Moore arrive at this figure as the pro rata share of a \$1.5 to \$2.0 billion conditioning plant designed for Alcan. Nowhere in their report do they show the effect on the project's economics of the higher conditioning costs which would be incurred if the Alcan pipeline was not built. Indeed, the \$1.02/MMBTU price they estimate an in-state petrochemical operation could afford to pay for LPG at the wellhead, assumes that Alcan is built. If Alcan is not built, conditioning costs of \$1 billion have been suggested verbally by Mr. Moore. At these costs, I estimate that the project could afford to pay only \$0.60/MMBTU for LPG at the wellhead (if I grant Bonner and Moore the remainder of their assumptions). While the producers might sell at this price if they have no alternative, they will not move quickly to do so.

My remaining reasons are:

- (3) Bonner and Moore's use of a single year to judge the profitability of in-state processing causes them to ignore the difference between (i) the return on equity per year (part of which should be thought of as a principal payment on equity invested), and (ii) the real yield on equity over the life of the investment. At the twelve percent per year return on equity suggested by Bonner and Moore (the industry average for 1977 and 1978), it would take approximately eighteen years of capacity operation just to earn back the initial investment (assuming a 6.5 percent annual rate of inflation). If the Prudhoe field can support a twenty-five year flow of LPG at the project's proposed capacity daily rate of flow, Bonner and Moore's annual return of twelve percent of equity translates into an expected real annual average yield over the life of the project of only two percent. In my opinion, given the market risk, this is too low an expected return to justify State participation. The availability of additional feedstocks from, say, the Beaufort, would improve prospects.
- (4) Bonner and Moore's \$711 million cost estimate for construction of the proposed 18 inch LPG pipeline from Prudhoe Bay to Kenai (via Fairbanks) may be optimistic. Dependent upon a variety of assumptions, such as the extent of worker overtime and the degree of "learning" since TAPS, likely estimates, in 1978 dollars, fall in the range of \$700 million to \$1.2 billion. (Based on construction cost data published in the August 14, 1978 Oil and Gas Journal.) A more detailed discussion of my own pipeline cost estimates is attached.

- (5) A near classic irrelevancy is the statement that "in-state use of gas liquids (may) provide the greatest net benefit to the State." (Bonner and Moore Report, p.3) If the State must invest to realize this net benefit, the proper criteria is net benefit relative to that achievable from the best alternative investment (tourism, fishing, hardrock mining, etc.). I am concerned that Bonner and Moore has missed this point, because they state (p. 3 of their report) that their recommendation is based, in part, on the belief that in-state processing will provide the greatest net benefit from the gas liquids.
- (6) It is not clear to me that the results of an engineering cost study would change matters much. According to Bonner and Moore's calculations, the \$711 million pipeline cost estimate translates into about 35.4¢ per MMBTU over the life of the project. If they were low by a factor of two, the effect would be to raise the 35.4¢ to about 71¢ per MMBTU. Since they have said that the gas liquids project cannot go unless Alcan fails, the effect of their being too low is to reduce the wellhead price payable by the project by 35.4¢ per MMBTU, say, from Bonner and Moore's \$1.02/MMBTU to \$0.66/MMBTU. If the gas liquids producers' only alternative use of LPG is field fuel, we may simply end up negotiating wellhead price in a lower range.

Furthermore, given our experience with the TAPS cost estimates, how much confidence would we have in the results of the engineering cost study? Would it really reduce our uncertainty that much?

It is difficult to understand the need to rush ahead with a \$225,000 cost study that may be partially or totally obsolete before any further steps can be taken. Suppose the study takes six months to complete and confirms Mr. Moore's \$711 million estimate? What have we gained? A possible six months? The fact, noted above, that at twelve percent per year it would take eighteen years just to recover the initial investment, strongly suggests that, even if an optimistic pipeline cost estimate is justified, the State should first determine the availability of feedstocks in addition to those from Prudhoe Bay, before making any large financial commitments. I believe \$225,000 is a large commitment.

While I agree with Bonner and Moore's conclusion that in-state processing may be feasible if Alcan is not built, I disagree with their recommendation to immediately fund a pipeline cost study. Admittedly, one has feelings of helplessness and frustration when one contemplates the possibility that Prudhoe Bay gas may go unused (no Alcan, no processing). However, it is precisely at such times that one must be most careful to guard against doing "something," just to be doing something.

Assuming Alcan is not built and that the State does not wish to extend large subsidies to a new petrochemical venture (would not Alpetco demand equal treatment?), the fate of a gas liquids venture is in the hands of the North Slope producers. Until they decide to sell their share of Prudhoe Bay gas liquids at a price that makes in-state processing feasible, we have no project. If we must do something, I suggest we begin to explore this question with the producers.

PIPELINE COST ESTIMATE

The method used here makes use of historical construction cost information published in the August 14, 1978 Oil and Gas Journal to develop an historical Alaska markup factor. This factor is then applied to the average per mile cost of constructing an 18 inch onshore pipeline in the "Lower 48" in 1978 to obtain an estimate in 1978 dollars of the per mile cost of constructing an 18 inch onshore pipeline in Alaska. Multiplication by 800 (800 miles) yields my best estimate of the total cost of the Prudhoe Bay to Kenai gas liquids line -- \$1.053 billion. Alternative estimates are also developed.

Alaska Markup Factor

The largest diameter pipelines for which cost figures are given in the August Oil and Gas Journal survey are two 42 inch crude oil pipelines laid in Michigan in 1974. Their respective per mile costs were \$487,782 and \$558,569 for an average of \$523,160. To account for cost increases for larger diameter pipe the average per mile cost of a 48 inch pipeline constructed in the "Lower 48" in 1974 is taken to be \$600,000.

The Oil and Gas Journal's pipeline construction cost index rose sixteen percent between 1974 and the middle of the TAPS construction period. Therefore, I take $\$600,000 \times 1.16$, or \$696,000 to be the average per mile cost of a 48 inch pipeline in the "Lower 48" during the TAPS construction period.

The Journal estimates that TAPS cost \$8.7 billion, excluding interest on borrowed capital. Subtracting (1) the capital cost of delivery facilities (\$1.444 billion primarily for Valdez), (2) pumping station equipment (\$617.7 million), (3) the haul road (\$200 million), (4) all other buildings (\$243.6 million), and (5) thirty percent of the cost of laying the pipe to account for excessive overtime (\$1.749 billion) leaves an adjusted TAPS cost of \$4.446 billion. It should be noted that this figure includes the \$165.3 million cost of line pipe, an item priced considerably below the average 1975-1977 cost because of prepurchase.

Given the \$4.446 billion total adjusted TAPS cost, the per mile cost in millions is then $\$4446/800$, or \$5.558 million.

The Alaska markup factor is then AMU where

$$\begin{aligned}\text{AMU} &= \text{TAPS cost per mile/Lower 48 cost per mile} \\ &= 5.558/.696 \\ &= 7.986\end{aligned}$$

Cost of 18 inch Pipeline

The average per mile cost of an 18 inch pipeline in the Lower 48 is calculated as the average of the Journal's reported 1978 costs for 16 inch and 20 inch pipelines, since there were no numbers reported for 18 inch pipelines, per se.

This procedure yields \$164,777 as the average 1978 per mile cost of an 18 inch pipeline laid onshore in the "Lower 48." Multiplying this by the Alaska markup factor of 7.986 yields \$1,315,909 as the per mile cost of an 18 inch pipeline laid onshore in Alaska in 1978. The estimated total cost of the Prudhoe to Kenai LPG line in 1978 dollars is then $\$1,315,909 \times 800$, or \$1.053 billion.

If one assumes a thirty-three percent reduction from this figure for "learning," or further reductions in overtime than those assumed above, one obtains Bonner and Moore's \$711 million estimate.

Point of note

The higher the estimated cost of building a 48 inch pipeline in the "Lower 48," the lower AMU and, thus, the lower my estimated cost of the LPG pipeline. I have taken \$696,000 to be the "Lower 48" per mile cost of a 48 inch pipeline constructed during the TAPS period. If we multiply the original (1970-1971) cost estimates given for TAPS (approximately \$1.2 million per mile) by the ratio of our adjusted TAPS cost, \$4.446 billion, to the total cost, \$8.700 billion, we get \$612,000, as the original (adjusted) per mile estimate for TAPS.

The original cost estimates for TAPS were too low for a number of reasons. One reason was unexpected inflation. In 1971 inflation was widely expected to proceed at about a two to three percent long-term average rate. Between 1971 and 1976 the actual annual average increase in the GNP deflator was about seven percent. A five percentage point per year excess of actual inflation over 1971

expectations yields a five year cumulative compounded excess of 27.6 percent. If the \$612,000 original (adjusted) per mile TAPS cost is increased by 27.6 percent, we get a figure of \$780,912. Adjusting for the full annual seven percent inflation from 1971 to 1976 yields an estimate of \$858,326 per mile.

Since \$780,912 is only 12.2 percent greater than my \$696,000 "Lower 48" cost per mile, and \$858,362 only 23.3 percent greater, my \$696,000 estimate may not be too small. The suggestion is that \$1.053 billion may not be an unreasonable estimate of the cost of the Prudhoe-Kenai LPG pipeline.

Construction costs in Alaska are often said to be about forty percent higher than in the "Lower 48." Replacing the \$696,000 estimate of "Lower 48" costs for a 48 inch pipeline by \$613,116 ($1.4 \times 613,116 = 858,362$) and recalculating AMU, yields an estimate for the Prudhoe-Kenai pipeline of \$1.2 billion.

Based on the analysis presented here it appears that the proposed Prudhoe-Kenai pipeline can be reasonably estimated to cost anywhere from \$700 million to \$1.2 billion in 1978 dollars dependent upon one's assumptions. The Bonner and Moore estimate of \$710.6 million is at the low end of this range.

DMR/va13/11



Bonner & Moore Associates, Inc.

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March 12, 1979

Mr. Don Wold
Executive Director
Alaska Royalty Oil & Gas
Development Advisory Board
Department of Natural Resources
323 East Fourth Avenue
Anchorage, Alaska 99501

Dear Don:

Mr. David M. Reaume of the Department of Commerce has issued an analysis of the report and recommendations presented by Bonner & Moore to the Royalty Board on February 1, 1979. Many of his comments are thoughtful and properly germane to the issue of in-state petrochemical development. Certain other of his comments appear to be inconsistent with supplemental information that was verbally presented to the Board along with the report contents. Since Mr. Reaume was not at that presentation this inconsistency is certainly understandable.

In this letter I will address each of the points raised by Dave and attempt to provide satisfactory answers to the difficulties he cites.

1) Impact of Future Petrochemical Developments
In Mexico

I don't consider that major petrochemical developments in Mexico will be a factor in world petrochemical supply for many years. Mexico will not find it desirable to finance such plants at the expense of the costly oil production programs they envisage. Furthermore, Mexico maintains strong foreign investment curbs that major petrochemical producers will continue to find too restrictive. Finally, the overall security of foreign investment in nations having the potential for socialist or Marxist revolutions is of serious concern. Mexico certainly must be regarded as having the potential for such developments even though the government has been a model of stability in Latin America.

Bonner & Moore Associates, Inc.

Mr. Don Wold
Alaska Royalty Oil & Gas
Development Advisory Board

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March 12, 1979

Dave criticizes the use of single year economics to project future market developments. Actually the Bonner & Moore report makes no pretense of including any petrochemical market analysis. Use of 1978 cost and price figures is only intended to quantify the various elements that determine the overall economics of petrochemical production. However, the fallout from Iran's revolutionary explosion has included the effect of dramatically increasing petrochemical prices and exports from the U. S. . I have stated repeatedly that petrochemical economics are cyclical. The high prices that will prevail over the next several months will probably be no more representative of a long term average than the very low prices of the past 1-2 years.

2) Impact of Gas Conditioning Costs on Gas Liquids Values

The points raised here are valid. Recovery of the gas liquids at Prudhoe Bay, in the absence of an Alcan gas line, will undoubtedly cost more than was indicated in our earlier study for the Department of Revenue. Furthermore, the actual cost can be determined only after a fairly complete design and engineering study. If these liquids are to be kept in-state the producers must be induced to undertake such a study promptly.

3) Impact of Future Cost Inflation on Petrochemical Investment Return

Dave's concern here probably stems from an unfamiliarity with petrochemical contracts. While he properly noted that inflation will reduce the real return on investment because the plant replacement cost rises, this is true only if product market prices don't inflate in amounts that cover the inflation of new plant construction costs. Petrochemical suppliers do not contract for long term fixed prices. The typical sales contract calls for "price re-openers" on a quarterly basis. If the market demand grows for petrochemicals then market prices must rise to support the cost of new plant investment. Old plants, therefore, become progressively more profitable, although, as Dave points out, some of that profitability is illusory because depreciation reserves are too low to reflect inflationary effects.

Bonner & Moore Associates, Inc.

Mr. Don Wold
Alaska Royalty Oil & Gas
Development Advisory Board

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March 12, 1979

4) Adequacy of Bonner & Moore's Earlier Pipeline
Cost Estimate

The earlier cost estimates were prepared by individuals experienced in the Alaskan construction environment. However, they were the roughest of approximations since so little time was devoted to their preparation. Better estimates must await more detailed site study and engineering.

5) Definition of "Greatest Net Benefit"

These comments are well taken since Bonner & Moore clearly has not considered any alternate uses for state capital spending. However, the term "greatest net benefit" seems to be used with regard to in-kind oil and gas royalty in a similarly inexact manner. We simply adopted the same terminology but it is certainly too sweeping in its implication. If we have indeed authored an irrelevancy, I suppose it is consoling to have achieved near classic proportions.

6) Value of a More Accurate Pipeline Cost Estimate

Dave's comments on this point show that Bonner & Moore's whole strategy for stimulating petrochemical development from gas liquids is not clear. Our recommendation to the Board was two-fold. One recommendation was to put together an engineering design, cost estimate, and financing package of sufficient substance to support the development of pipeline transportation costs for presentation to prospective shippers. The second recommendation was to determine how a pipeline operating company should be organized, at least in an interim promotional status. This company would begin to promote the use of a gas liquids pipeline to producers and prospective purchasers of gas liquids as soon as the investment and cost study were complete. The premise is that if the state makes a credible enough representation about sponsoring the future construction of a pipeline, serious consideration will be given to in-state petrochemical investments. If the second recommendation is not followed then Dave's reservations about the value of an engineering design and cost estimate are well taken.

Bonner & Moore Associates, Inc.

Mr. Don Wold
Alaska Royalty Oil & Gas
Development Advisory Board

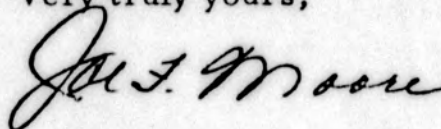
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March 12, 1979

I think it is most timely to proceed on this matter. The situation in Iran has made petrochemical producers all over the world re-evaluate their raw material, marketing, and investment strategies. The elements favoring Alaska as a location for petrochemical plants are currently reinforced in their importance by world events.

I hope these comments will alleviate most of David Reaume's concerns. The time and attention that has been devoted to his analysis is most appreciated.

Very truly yours,

A handwritten signature in cursive script, appearing to read "Joe F. Moore".

Joe F. Moore
President

JFM:me

STATE
of ALASKA

MEMORANDUM

TO: ☐ Richard Eakins
Director

DATE: March 29, 1979

FILE NO:

TELEPHONE NO:

FROM: David Reaume *DR*
Principal EconomistSUBJECT: Bonner & Moore
Letter of
March 12, 1979

Joe Moore's response to my comments pretty much leaves them where they stand. We obviously disagree on the Mexican potential. (For my part, I am not sure why a socialist revolution in Mexico would prevent Mexico from becoming a world leader in petrochemicals, as suggested by Mr. Moore, unless the revolution lasted very many years. They obviously do not need private capital and can purchase the technology.)

If I may paraphrase his response, it appears to be "Dr. Reaume is largely correct, but you should proceed with my suggestion anyway." I am content to leave it at that (having agreed to disagree on Mexico) and let State decision-makers decide whose advice they wish to follow, except for one point.

Mr. Moore suggests that allowance for rising petrochemical prices invalidates my statement that, at an annual rate of return of 12.0 percent, it would take over eighteen years just to get back the equity investment. I am afraid I must disagree. A constant 12 percent rate of return could only be achieved, in the face of rising costs, if product prices also rise. In order to shorten the payback period to less than eighteen years, Mr. Moore must show that the rate of return on equity rises over time. I welcome such an attempt on his part. My whole point is that Mr. Moore needs to back up his assertions, not just re-echo them.

In my opinion, it takes more in the way of concrete analysis to justify his proposed strategy.

DR/mh4/12

**PLEASE NOTE: THE PRECEDING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT.**

PRUDHOE BAY NATURAL GAS LIQUIDS,
THE ALASKA HIGHWAY GAS PIPELINE,
AND PETROCHEMICAL DEVELOPMENT IN ALASKA

A Review of the November 1, 1979 Report,
PROMOTION AND DEVELOPMENT
OF THE
PETROCHEMICAL INDUSTRY IN ALASKA

by Bonner & Moore Associates, Inc.

to the

Alaska Department of Natural Resources
Royalty Oil and Gas Development Advisory Board

By CONNIE C. BARLOW
ARLON R. TUSSING AND ASSOCIATES, INC.

20 January, 1980

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FOREWORD BY ARLON R. TUSSING

This review began as a private memorandum Connie Barlow wrote at my request for members of our organization and a few professional colleagues. In it she summarized the November 1979 report of Bonner & Moore Associates, Inc. (B&M) to the State of Alaska on the outlook for establishing a new in-state petrochemicals industry based upon natural gas liquids from Prudhoe Bay. She also related B&M's findings to the most controversial current policy issues regarding the disposition of the various North Slope hydrocarbons.

Ms. Barlow's reading of B&M was in startling contrast to the things we had heard about their report. Instead of setting out a strategy for assuring the feasibility of a gas liquids-based petrochemical facility, their analyses seemed to add up to a powerful case against the very development strategy they describe.

The issues involved are of great importance to Alaska, but they are also exceedingly complicated. The B&M report, moreover, is often obscurely written and many --- if not most --- of its key assumptions and sources are unstated. All these considerations argued for a wider distribution of Ms. Barlow's review; but they also demanded an especially careful verification of her interpretation of B&M, and careful editing of any public version.

We sent drafts of this paper to B&M for comment, and also to their subcontractor Birch, Horton, Bittner, and Monroe; to the major Prudhoe Bay gas producers; to Northwest Alaskan Pipeline Company; and to a number of state and federal officials concerned with North Slope oil and gas production, the gas pipeline, and petrochemicals development.

The time my cover letter allowed for response to the review draft did not allow all of these parties to scrutinize it with the thoroughness the review's author gave the B&M report. We did, nevertheless, receive expert and helpful comments from several industry and governmental sources. A group of executives and engineers from one of the producing companies deserves special thanks for spending a day with Ms. Barlow and me, helping to clarify our understanding of the relationships among a number of physical and engineering principles, Prudhoe Bay hydrocarbon balances, and the Parsons design for a North Slope gas conditioning facility.

The basic understandings in Ms. Barlow's first memorandum stood up very well under this intensive review process. We have changed a few numbers and made some editorial improvements, but the thrust of the original review remains intact: B&M do not state a case in favor of gas liquids-based petrochemical manufacturing in Alaska, but rather a case against it.

Neither the B&M report nor the Barlow review is the last word on this issue. Another strategy and another analysis may well demonstrate the feasibility of some kind of petrochemicals venture in the state --- but B&M have not yet presented such a strategy or analysis.

This review is offered to Alaskans as a public service of Arlon R. Tussing and Associates, Inc. It was not produced under contract to, or with funding from, the state of Alaska or any other interested party.

I. INTRODUCTION AND SUMMARY

Bonner & Moore Associates, Inc. (B&M) in November 1979 submitted a report titled Promotion and Development of the Petrochemical Industry in Alaska to the Alaska Department of Natural Resources, Royalty Oil and Gas Development Advisory Board. In the coming year, state officials, legislators, and individual Alaskans will surely cite this study in support of or opposition to proposals for state action to create a local petrochemicals industry using natural gas liquids from Prudhoe Bay.

Unfortunately, the B&M report does not set out its major findings clearly and systematically in any one place, nor does it relate these findings explicitly to the policy issues that have caused the greatest concern or controversy among various Alaskan groups, the North Slope gas producers, the gas pipeline sponsors, and federal agencies. Even more unfortunately, B&M's executive summary will badly mislead any reader who does not read the entire report carefully and critically.

For these reasons, this review is designed, in part, to point out the policy significance of B&M's analyses. We have generally chosen to overlook any disagreements we may have with the report's assumptions and analytical methods --- because even if B&M's calculations are accepted at face value, their logical implications dramatically contradict the executive summary's "affirmative conclusion that a project can be developed in Alaska that would produce ethylene-based petrochemicals for the Pacific market with acceptable profitability".[emphasis added]

Our review also examines the effects of the B&M scenario on various parties with an interest in the Alaska Highway gas pipeline. While an analysis of these impacts was not clearly part of B&M's study mandate, the costs imposed on other interests by removing natural gas liquids from the sales gas may well be tossed back into the lap of the party that receives the liquids. Some of these effects are substantial, and therefore demand close attention from policy-makers who would look to B&M for practical guidance.

Some of the most important implications that this review draws from B&M's analysis are the following:

- *** The B&M scenario requires a change in the gas conditioning process and field fuel design at Prudhoe Bay. Not only would this change negate the Parsons' design and require a whole new conditioning study, but the end result may substantially raise the cost of gas conditioning.
- *** Removing 107,000 barrels of natural gas liquids per day from the hydrocarbon stream destined for the Alaska Highway gas pipeline would increase the unit transportation costs of the remaining gas by about 16 percent. The heating value of the gas stream would fall from 1106 to 1050 (gross) BTU per cubic foot.
- *** As much as one-fifth of the total energy available to the nation from Prudhoe Bay natural gas could well be lost if a project like that suggested by B&M is put into effect.
- *** In order to secure the volume of gas liquids required by the B&M strategy, Alaska could earmark all of its royalty gas liquids, and swap all of its royalty gas (methane) for gas liquids owned by the producers; but the project would still be substantially short of its required volumes.

*** Unless something happens to cause a radical improvement in the economics of the petrochemicals venture described by B&M, their own analysis indicates that it can not operate profitably and pay the state of Alaska anything at all for the ethane it requires as feedstock. In B&M's base case the state would be required to subsidize the project by the equivalent of at least 36 percent (63 cents per MMBTU in 1979 dollars) of its entire Prudhoe Bay royalty gas income.

II. DESCRIPTION OF THE PROPOSED PROJECT

The Bonner and Moore Associates, Inc. (B&M) report, Promotion and Development of the Petrochemical Industry in Alaska, considers the logistics and economics of using North Slope natural gas liquids as feedstocks for a new petrochemicals manufacturing plant to be built in Alaska. In order to perform a detailed analysis the report "creates a 'for instance' project embodying generally conservative premises . . ."¹ The B&M strategy entails:

- *** construction of a natural-gas-liquids pipeline from Prudhoe Bay to Cook Inlet,
- *** to carry roughly 25 percent (25 thousand barrels per day) of the ethane (C_2) produced from the Prudhoe Bay reservoir,
- *** for use as feedstock in a world-scale petrochemicals manufacturing plant near Kenai that would produce about 1 billion pounds of ethylene per year,
- *** which the plant would process further into four basic liquid petrochemicals --- low- and high-density polyethylene, ethylene dichloride, and vinyl chloride,
- *** for export to Japan, where final processing would take place.

Incidental to the transportation of ethane and manufacture of petrochemicals, B & M propose that:

- *** the natural gas liquids pipeline carry almost all of the propane (C_3) and butanes (C_4) separated from the methane (C_1) during natural gas conditioning,
-

1) Joe Moore, letter to Tussing [January 4, 1980].

*** for export as LPG (liquefied petroleum gas) into world markets

The functions of these latter activities, which are not part of the petrochemical operation in itself, are:

*** to provide a greater throughput volume for the natural-gas-liquids pipeline, thus reducing transport costs for ethane, and possibly

*** to cushion petrochemical marketing risks with profits from LPG sales.

III. IMPACT OF THE PROJECT ON NORTH SLOPE OPERATIONS

The B & M report states that its petrochemical development strategy would require two modifications in the present plans for gas processing and conditioning on the North Slope: (1) addition of an ethane extraction facility, and (2) a change in the fuel mix for field operations.

The first modification adds a facility on the North Slope to extract 25 thousand barrels of ethane per day from the roughly 60 thousand barrels that would remain in the "sales gas" stream after conditioning.² Quite rightly, the B & M report assumes that the costs of ethane extraction would be borne entirely by the liquids purchaser(s), and thus should impose no direct cost burdens either on the gas producers or on the purchasers of sales gas shipped through the Alaska Highway gas pipeline.

The report, however, does not acknowledge the full impacts of its petrochemical strategy on North Slope fuel availability and overall conditioning design. The conditioning plan now under consideration (the Ralph M. Parsons study) anticipates that the ethane-CO₂ "waste-gas" mixture generated during the conditioning process can be used for fuel if it is further enriched by adding more than half of the propane that the fractionation plant will make available.

- 2) While shipping all 60 thousand barrels per day of available ethane through the gas liquids line could further reduce unit costs of transportation, the report indicates that the cost of high pressure facilities for storage of ethane in liquid form would offset any transportation cost savings. [p. 7-1]

The B & M strategy, however, calls for shipping all of the separated propane through the gas-liquids pipeline. (See Table I.) Accordingly, the report assumes that "field gas" will be used as fuel instead. [p. 3-9] (We assume that field gas is the methane-rich raw gas, less the heavier NGLs and water.)

This change in fuel composition inevitably demands a change in design for the entire conditioning process: Unless propane is available, there is no practical way to enrich the ethane-CO₂ waste gas mixture; hence, a conditioning process that fully removes all hydrocarbons from the CO₂ stream would have to be used.

Such a modification would require a completely new engineering study and might well result in higher overall gas conditioning costs. The B & M report does not acknowledge any such additional costs, and consequently, makes no provision for allocating them to the responsible party --- that is, the petrochemical operation.

IV. EFFECTS OF THE PROJECT ON NORTH SLOPE GAS PURCHASERS AND ON UNITED STATES NET ENERGY SUPPLY

If almost half the ethane and all of the propane and butanes were removed from the sales gas stream shipped through the Alaska Highway gas pipeline, the total caloric value of the gas would be reduced substantially. Gas purchasers would suffer both the effects of (1) a leaner gas stream (fewer BTU per MCF), and (2) higher transportation costs per unit of gas. Export of the petrochemicals from the United States, and possibly of the LPGs as well, would result in (3) a net reduction in domestic U.S. energy supply, which would have to be offset by an increase in crude oil imports.

Table I shows the approximate volumes and BTU content of the hydrocarbons (1) fed into the conditioning plant, (2) consumed as fuel for gas production and conditioning, and (3) available for shipment from the North Slope through the IAPS oil pipeline, the Alaska Highway gas pipeline, or some other transportation facility like the gas liquids pipeline proposed by B&M.

Table II shows how the B & M strategy for petrochemical development would affect the composition and volume of the sales gas, and thereby its market quality and unit costs of transportation through the gas pipeline.

B & M's scenario would reduce the gross heating value of the sales gas from 1106 to 1050 BTU per cubic foot. While 1050 may approach the minimum BTU richness specifications for Lower 48 pipelines, this heating value reduction in itself poses no real threat to gas marketability.

However, the B & M scenario would reduce the total energy content of the sales gas by about 386 billion BTU per day, or 17 percent. The fixed costs and total costs per BTU for pipeline transportation would thus increase by about 20 percent and 16 percent respectively.³ This is a significant increase, and federal regulators may well be moved to consider allocating those cost increases to the responsible party -- the liquids purchaser(s).

Of the total energy removed from the gas pipeline, 68.5 billion BTU per day in the form of ethane would be converted into non-fuel petrochemicals for export to Japan. B & M are vague about LPG markets, but if these liquids too were exported, the entire 386 billion BTU per day would be a net loss of domestic energy to the U.S. economy. To this total must be added fuel for the ethane extractor and the petrochemicals complex. At least part of this demand would be met by hydrocarbons that otherwise would have reached the Lower 48 as natural gas or crude oil. Unfortunately, B & M do not give us figures on the amount of energy these facilities would require.

If chlorine --- a necessary ingredient in two of the four petrochemicals the plant is to produce --- were manufactured in Alaska, both steam and electricity would be needed. Here, we can at least impute energy demand from the B & M report: 60 billion BTU per day.⁴ Altogether, it is conceivable that this project might reduce the total volume of Alaska energy available to the United States as natural gas or crude oil more than 500 billion BTU per day --- over one fifth of the energy the gas pipeline would otherwise contribute.

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- 3) These figures are for the entire pipeline system, excluding Northern Border. An 17 percent reduction in BTU shipments corresponds to a 13 percent reduction in MCF. The result would reduce total compressor fuel use by 23 percent in Alaska and 13 percent in Canada.
- 4) \$143,200/day @ \$195/ton = 735 tons/day;
755 tons/day @ \$186/t @ \$2.25/MMbtu = 60 billion BTU/day.

V. EXCHANGING STATE ROYALTY METHANE FOR NATURAL GAS LIQUIDS

Under the Prudhoe Bay lease contracts, the state owns a one-eighth royalty interest in each of the two streams of hydrocarbons (oil and gas) produced from the lease, and may elect to take its royalty either in money or in kind. If the state takes its natural gas royalty in kind, it has to take one-eighth of each of the produced hydrocarbons --- methane, ethane, propane, butanes, and pentanes-plus --- in such combinations as they come from the processing and conditioning facilities.

The state's share of NGLs available falls short of the B&M NGL requirements by 328 billion BIU per day. For this reason, state officials are negotiating with the gas producers, and with federal agencies that might have some regulatory jurisdiction over the disposition or pricing of Prudhoe Bay natural gas liquids, for an option to exchange the state's royalty share of the methane for sufficient natural gas liquids to provide feedstocks for an Alaska petrochemicals plant.

Is such an exchange feasible? Specifically, will the state have enough royalty methane to obtain the additional barrels of NGLs in a BIU-for-BIU swap? Table III shows that the state could take its entire royalty share of Prudhoe Bay ethane, propane, butanes, and pentanes in kind, and swap its entire royalty share of methane to the gas producers for additional natural gas liquids, and still be 109 MMCF per day short.

In other words, the state would need to control 50 percent more methane than it owns at Prudhoe Bay in order to implement the B & M proposal, even if it disavowed any interest in retaining some pipeline gas for residential and commercial consumption in Alaska communities. Unless the petrochemical company were able to buy sufficient gas liquids directly from the producers to make up the deficit, the state would have to do so in its behalf.

VI. FINANCING THE PROPOSED FACILITIES

The B&M proposal requires construction of three separate facilities:

- *** A petrochemicals complex on Cook Inlet with a (1979) capital cost of \$931 million,
- *** A 16-inch natural gas liquids pipeline from Prudhoe Bay to Kenai with a capital cost of about \$687.3 million,⁵ and
- *** An ethane-extraction facility at Prudhoe Bay with a capital cost of about \$58 million.⁶

Under both state and federal law, the gas liquids pipeline would have to operate as a common carrier, providing service to all shippers without discrimination, to the limit of its capacity. As a result, the gas liquids pipeline would actually have to be built with a capacity considerably greater than the 107 thousand barrels per day proposed by B&M, in order to assure the petrochemicals plant it would receive 25 thousand daily barrels of ethane every day over the economic life of the facility.⁷

- 5) The B&M report does not mention the cost or even the diameter of the proposed gas liquids pipeline. We have therefore used a subcontractor's estimate from B&M's earlier report to the state [State of Alaska --- Utilization of Royalty Gas (January 23, 1978)]: Pipe Line Technology, Inc., State of Alaska Feasibility Study of Pipeline Transportation, Royalty Gas and NGL (January, 1978), p. 49. We inflated the 1977 capital cost figure (\$574.5 million) from that report to mid-1979 dollars at the rate of increase in the Oil and Gas Journal's pipeline cost index between 1977 and the first quarter of 1979. [O&GJ, November 19, 1979]
- 6) Nowhere in B&M's report is there a statement of the ethane facility's capital cost. The cost of extracting 25,000 barrels per day, however, is given as \$1.03 per barrel of recovered ethane [p. 6-5]. Our figure of \$58 million assumes that the \$1.03 is composed entirely of fixed costs (return of and to investment), leveled in equal annual installments over 20 years at a 15 percent rate of return on total capital.

B&M conclude that even if Alaska succeeded in attracting a firm to build, own, and operate a petrochemicals plant in the state --- and engage in LPG marketing on the side --- it is unlikely that this firm would also be willing to bear the financing and ownership burdens of the other two facilities.⁸ Hence, the state must either (1) make an additional effort to recruit a firm (or firms) to finance and operate the ethane extraction plant and the liquids line, or (2) take on the burdens of financing these two facilities.

- 7) Whenever the total volume of natural gas liquids, LPGs, light refined products such as naphtha and gasoline, and possibly even jet fuel, distillate fuel oil and diesel oil, tendered for shipment exceeded the pipeline's shipping capacity, it would have to accept shipments by all parties ratably, that is, proportionally to their respective tenders.

If tariffs on the gas liquids pipeline were to be as low as projected by B&M (less than half the average IAPS tariff), and if a profitable market did exist for North Slope LPGs at Cook Inlet, it is likely that at least some of the producers would seek to ship any of their Prudhoe Bay LPGs (the pentanes-plus, for example) not committed to the petrochemicals firm via the liquids line. If new supplies of LPGs became available from other reservoirs on the North Slope, they might also seek space in the line, while the North Slope topping plant and the North Pole refinery are potential shippers of naphtha or light distillates to the Anchorage area. If the line were designed to carry only 107 MB/d, any of these shipments would displace part of the ethane intended for the petrochemicals plant.

Neither B&M nor (surprisingly) Birch, Horton, Bittner & Monroe, in their subcontractor report to B&M, Government Controls Affecting Development of an Alaskan Petrochemical Complex using North Slope Natural Gas Liquids Feedstock [August 23, 1979] mentions the common carrier issue.

- 8) "The total investment costs for a liquids pipeline, extraction equipment, and a petrochemical complex are considered to be too great for a single petrochemical producer to bear, since all these investments are subject to identical market risks and are perhaps two to three times as high as for a petrochemical facility built at an established center." [p. 2-4]

VII. SITING CONSIDERATIONS

Bypassing Fairbanks. While B&M have consistently stated that petrochemical development need not by-pass Fairbanks, it is clear that none of the related facilities absolutely depends upon a Fairbanks location. The scenario chosen by B&M for demonstration purposes, for example, places the exthane extractor in the same location as the Prudhoe Bay gas conditioning and processing facilities, and the petrochemicals complex on Cook Inlet. Hence, Fairbanks would get neither of the facilities that its business and government leaders have so avidly sought.

The report does state, however, that "locating the gas-processing plant at Prudhoe Bay will probably result in higher investment and operating costs than the same facility at Fairbanks." [p. 2-2] B&M do not substantiate this judgment, but they pragmatically suggest that the state gauge the economic feasibility of the liquids project on the basis of the most likely even which, given recent FERC decisions, certainly point to a Prudhoe Bay location for gas conditioning. The report does not address the economics or the practical prospects of locating the petrochemical complex itself in Interior Alaska.

Air quality. The report notes that a petrochemical complex in either Anchorage or the Fairbanks-North Pole area might have difficulties in meeting air-quality standards --- even if natural gas rather than coal were used for plant fuel. While Kenai can probably bear the additional air pollution, federal regulatory standards are not likely to allow both the petrochemical complex and the proposed PAC-Alaska LNG plant to be located there. [p. 4-11]⁹

- 9) Joseph M. Chomski of Birch, Horton, Bittner & Monroe (subcontractors to B&M) has criticized this interpretation of page 4-11, citing language in the Birch et al appendix to B&M's report: "The Kēni area has not used up its air pollutant increment yet, despite several industrial facilities already located in the area. However, there is a proposed LNG facility that could use up the increment and foreclose the petrochemical plant siting option due to air pollutant loading. [letter to Barlow, January 7, 1979 (sic)]" Failing to see any substantive difference between the words of our review draft and the subcontractor's own language quoted above, we have maintained our original wording.

VIII. ECONOMICS OF PETROCHEMICALS MANUFACTURING IN ALASKA

Qualitative outlook. B & M cite two main qualitative factors that might attract a chemical company to Alaska:

1. Relatively stable feedstock prices; more properly, feedstock prices that will rise at a predictable rate, [pp. 2-5 and 8-4], and
2. A large and relatively secure supply of natural gas liquids. [pp. 2-5 and 8-4]

The report cautions, however, that three other factors create special burdens for any prospective Alaska petrochemicals producer:

1. Alaska construction will cost about 1.6 times that of comparable facilities on the U.S. Gulf Coast. [p. 2-4]
2. In order to bring ethane to a Cook Inlet facility, someone must build an ethane extractor at Prudhoe Bay and a gas liquids pipeline the length of Alaska: no prudent company would take on the risks of all three of these investments. [p. 2-4]
3. The total risks of such a project in Alaska are two to three times as high as they would be in an established petrochemicals center. [p. 2-4]

Nevertheless, the B & M report judges that the attractions can be expected to outweigh the special burdens of an Alaska location. Joe Moore, in his January 4 letter, refers to ". . . the obvious and overwhelming economic concern of industry, namely that security of feedstock supply and future feedstock cost escalation are the project planning parameters of greatest importance." The following section examines this contention in further detail.

Quantitative outlook. The B&M report [p. 6-5] calculates the volumes of hydrocarbons required by the Cook Inlet petrochemical complex, and their 1979 dollar prices at the plant entrance, as follows:

	Volume (bbl/day)	Price (¢/gal) (¢/lb)		Total Cost (per day)
Ethane (C ₂)	24,713	23.3	7.5	\$289,586
Propane (C ₃)	57,556	27.9	6.6	674,441
Butanes (C ₄)	20,354	31.0	6.5	265,009
Pentanes-plus (C ₅ +) 3	4,194	33.6	6.4	59,185

These delivered prices reflect [page 2-3]:

- *** \$1.75/MMBTU for the Prudhoe Bay gas purchase price.
- *** \$0.50/MMBTU for CO₂ removal at Prudhoe Bay.
- *** \$1.03 per barrel for ethane extraction at Prudhoe Bay.
- *** \$2.94 per barrel for the gas liquids pipeline tariff.

B&M do not reveal how they calculated the costs of ethane extraction or of pipeline transportation for the natural gas liquids, nor the basis for their estimates of petrochemical market values in Japan and on the U.S. West Coast. We, therefore, have no basis for evaluating whether these costs are truly realistic. Nevertheless, even if the values in the report are assumed to be correct, they mean that the cost of ethane delivered to the petrochemicals complex will be too high to permit production of marketable ethane derivatives. For, while B&M calculate the cost of ethane delivered to Cook Inlet at 7.5 cents per pound, the petrochemicals complex could afford to pay only 4.3 cents per pound in order to compete in Japanese markets, and only 4.0 cents to compete on the U.S. West Coast [pp. 8-4 and 8-7].¹⁰

- 10) B&M's projections of maximum affordable ethane prices are those that would meet current 1979 market prices for ethylene derivatives. [Joe Moore, letter to Tussing, January 4, 1980]

The report offers several possibilities for improving this dismal outlook:

First, if the petrochemicals complex owner were willing to accept a rate of return on total investment of only 7.3 percent in place of the 15 percent assumed in the report, Alaska petrochemicals might be competitive in Japan. With a 6.3 percent rate of return, they might be competitive in the United States. [p 8-7] This hope hardly deserves a second look. If the petrochemicals complex were financed with 75 percent debt at 11.5 percent --- the current rate for high-grade industrial bonds --- any return to total investment less than 8.6 percent would yield a negative rate of return to equity.

Second, if the LPGs delivered to Cook Inlet could be sold at a sufficient profit, the cost of ethane delivered to the petrochemicals plant would be reduced from 7.5 to 6.0 cents per pound. [p. C-3] This is still 40 percent higher than B&M's calculation of the maximum ethane price for penetration of the Japanese market, and 50 percent higher than the maximum price for sales within the U.S.

Hope of offsetting losses on the petrochemical operation with profits from LPG sales seems tenuous at best, in view of B&M's earlier observation about the world market outlook for LPGs: "Although the crude oil situation is tight, ample supplies of natural gas liquids exist . . . With this surplus, the Oil and Gas Journal indicates that the world-wide liquefied petroleum gas (LPG) market may offer unsatisfactory prices for exporters." [p. 3-3]. Nevertheless, B&M maintain that the Alaskan LPG sales can operate profitably: "...our projected price for LPG fully takes into account a future surplus of these materials which deprive them of their premium value experienced in recent years." [Joe Moore, letter to Tussing, January 4, 1980]

B&M touch upon two other possibilities for bridging the gap between maximum economic prices for ethane and its cost to the petrochemicals complex. The report mentions a "significant" prospect for reducing transport costs by backhauling vegetable oils from Japan, but does not elaborate further. [p. 5-2]

Alternatively, if no attempt were made to recover plant investment by means of depreciation, to repay principal and pay interest on borrowed capital, or to capture any return on equity, B&M conclude that the petrochemicals complex could afford to pay 6.5 cents per pound for ethane, rather than 4.3 cents [p. 8-4]. Even this "cash-cost" approach leaves the petrochemical facility with feedstock costs 25 percent higher than B&M indicate it could afford to pay.

Moreover, while the investors in existing facilities (say, in Japan) might have no alternative but to accept a "cash cost" price that covers only feedstock and other operating costs, in order to retain customers in a buyers' market, no prudent management would decide to build a new facility if penetration of the market appeared to require "cash-cost" pricing from the outset.

Finally, if feedstock prices were to rise at an annual rate 3.4 percent higher in Japan than in Alaska, the B&M report concludes that ethylene derivatives produced in Alaska might become competitive in five years [p. 8-7]. Unfortunately, B&M do not explain to their readers how a 3.4 percentage-point differential in annual price escalations would bridge the gap between a value of 4.3 cents and a cost of 7.5 cents in five years.

In addition, the report fails to account for the unusual market penetration barriers likely to exist in Japan, in the form of long-term contracts with joint-venture plants in oil-producing nations, protectionist policies on behalf of Japan's domestic petrochemicals industry, or the discounting of prices below "full costs" --- perhaps as low as "cash costs" --- attendant on a quite plausible world oversupply of ethylene.

Even if the report's conclusions with respect to differential feedstock price escalations are valid, the reader must also consider the economic handicaps noted in this review, which the B&M report did NOT take into consideration.¹¹ All in all, none of the offsetting features that B&M note seems to be substantial, certain, or realistic enough to persuade any prudent management to invest in Alaska petrochemicals development in the manner suggested by the report, or even to consider it seriously.

The need for a subsidy. Using B&M's base case figures, the only certain way to bring the ethane "cost" at Cook Inlet (7.5 cents per pound) down to the ethane "value" (4.3 cents per pound), would be for the state to pay the liquids purchaser(s) \$.90 per MMBTU for the 68.5 billion BTU per day of ethane delivered. If the required subsidy were spread over all of the state's royalty gas and gas liquids from Prudhoe Bay, Alaska would end up with only \$1.12 per MMBTU (\$318,500) for its share of production, rather than the \$1.75 per MMBTU (\$500,500) the state would have received each day in revenue from gas shipments through the Alaska Highway pipeline.¹²

11) Joe Moore replies that the author of this review " . . . devotes several pages to impacts on the gas pipeline project. We did not treat that subject and I will not comment on it here." [letter to Tussing, January 4, 1980]

Granted, Joe Moore [in his January 4 letter] characterizes the report's contrast between an ethane cost of 7.5 cents and a value of 4.3 cents per pound as a "worst case" example on the ground that those numbers do not reflect any of the offsetting factors he mentions elsewhere. But as we have pointed out, some of these factors do not look particularly promising; these "worst-case" cost calculations, and in addition, wholly fail to take into account the collateral costs (new conditioning design, higher gas pipeline tariffs) that are inescapable if most of the liquids are removed from the sales gas stream.

The preceding calculations, moreover, accept at face value one crucial assumption by B&M which is clearly not the worst case but the best --- namely that the price of hydrocarbons at the tailgate of the conditioning plant, and hence their value in the sales gas stream, will be \$1.75 per MMBTU (in 1979 dollars). This figure is in reality an absolutely irreducible and highly improbable minimum.

- 12) Manner of calculation. We imputed the maximum price that the petrochemicals manufacturer can afford to pay for ethane delivered to its plant gate from the ratio between B&M's value and cost figures:

$$\frac{(\$0.043)}{(\$0.075)} \times (\$1.75 + \$0.50 + \$1.03 + \$2.94) = \$3.57 \text{ per MMBTU.}$$

But the irreducible cost of separating the ethane and of transporting the natural gas liquids is:

$$\$0.50 + \$1.03 + \$2.94 = \$4.47 \text{ per MMBTU.}$$

Hence, even if the petrochemicals manufacturer received the gas at Prudhoe Bay totally free of charge, somebody would have to make up the 90 cent deficit on each MMBTU of the 68.5 billion BTU shipped daily --- a total of \$61,600 per day. As the producers are unlikely to sell or exchange their Prudhoe Bay hydrocarbons for any price less than they would have received by shipping them through the gas pipeline (much less pay someone to take them away), the state would have to absorb the entire deficit of \$2.65 per MMBTU, or \$181,400 per day. In relation to the entire state royalty share of 285,600 billion BTU per day, the implied subsidy would be \$0.64 per MMBTU.

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While the \$1.75 conforms to a preliminary FERC ruling that allocates all conditioning costs to the gas producers, the outstanding gas sales contracts add these costs to the \$1.75 wellhead price, and the Department of Energy has asked FERC to withdraw its decision and leave the matter up to negotiations among the parties.¹³

It is not unlikely that the final settlement of this issue will provide for addition of 30 to 50 cents per MMBTU to the sales gas price as a partial allowance for conditioning costs. Using the same methods as above, a 30 cent allowance would increase the cost of the whole 395,800 MMBTU per day --- and also its value as part of the sales gas --- by \$118,700, to a total of \$811,400 per day. The project's revenue deficit would increase by the same amount, and its economics would be further worsened, to the extent of 42 cents for each of the state's 265,600 MMBTU per day of royalty gas and gas liquids. If FERC should agree to a conditioning cost allowance exceeding 30 cents the project's losses would, of course, be increased proportionally.

13) B&M might conceivably be excused for passing over this issue, but it is surprising that the Birch, et al, appendix to the B&M report, which devotes 23 pages to "Government Controls on Natural Gas and Gas Liquids" and "Feedstock Price Controls and Related Issues," makes no mention whatsoever of the current proceedings regarding the allocation of conditioning costs, which can have such a powerful influence on feedstock prices, and thus on the economics of the proposed petrochemicals plant.

TABLE 1. THE AVAILABILITY OF LIQUIDS FOR SHIPMENT THROUGH TAPS, THE GAS PIPELINE, OR A GAS LIQUIDS LINE

HYDRO-CARBON	INLET GAS ² to condition- ing plant	FIELD FUEL ³	PLANT FUEL ⁴	AVAILABLE HYDROCARBONS ⁵	B&M LIQUIDS ACQUISITION ⁶
C ₂	111.4 Mb/d	39.2 Mb/d	14.5 Mb/d	58.1 Mb/d ⁷	24.7 Mb/d
C ₃	61.8 Mb/d	22.5 Mb/d	16.7 Mb/d	23.3 Mb/d ⁸	57.6 Mb/d ⁸
C ₄ (i)	10.3 Mb/d	.8 Mb/d	.3 Mb/d	9.4 Mb/d	none
C ₄ (n)	23.7 Mb/d	.9 Mb/d	.1 Mb/d	23.3 Mb/d	20.3 Mb/d
C ₅ (i)	6.2 Mb/d	.1 Mb/d	none	6.3 Mb/d	4.2 Mb/d
C ₅ (n)	11.4 Mb/d	.1 Mb/d	none	11.7 Mb/d	none
C ₆₊	9.7 Mb/d	none	none	10.2 Mb/d	none
TOTAL	234.5 Mb/d	63.6 Mb/d	31.6 Mb/d	142.3 Mb/d	106.8 Mb/d

1. Unless otherwise noted, these figures reflect the data provided by the Ralph M. Parsons study report, Sales Gas Conditioning Facilities: Prudhoe Bay Alaska, (which assumes 2.0 bcf/day of sales gas with a minimum of 1 percent CO₂). The translation of the Parsons' data into barrels is based on a table prepared by Exxon USA entitled "Material Balance: Prudhoe Bay Conditioning Plant" [undated]. The vertical and horizontal totals are not precisely consistent, and Table 1 reflects those disparities.

2. INLET GAS consists of the total gas production, less volumes removed by the existing Field Fuel Gas Unit (FFGU) for use in the first four TAPS pump stations and for oil-related field activities.

3. FIELD FUEL is a projection of the maximum fuel volume required for waterflood, artificial lift, etc., less the volume of fuel supplied by the existing FFGU, as calculated by Parsons.

4. PLANT FUEL consists of fuel needed for local heaters and local turbines within the conditioning facility.

5. AVAILABLE HYDROCARBONS are the remainder available for shipment through TAPS, a natural gas pipeline, and/or a natural gas liquids line, after field and plant fuel requirements are provided for.

6. B&M LIQUIDS ACQUISITION reflects the data shown on page C-3 of the B&M report. While B&M state that, "All of the propane and heavier liquids are recovered for a total NGL volume of 107,000 B/D," the B&M figures are not consistent with the volumes of avails calculated by Parsons.

7. 53.3 Mb/d of the initial 111.4 Mb/d remains in the CO₂ waste gas stream.

8. Of all hydrocarbons, only propane (C₃) is available in volumes less than B&M propose for acquisition. The deficit is substantial: 23 thousand barrels per day available, in contrast to 58,000 barrels required.

TABLE 2. THE EFFECT OF THE BONNER AND MOORE STRATEGY
ON THE VOLUME AND RICHNESS OF GAS AVAILABLE
FOR TRANSPORT THROUGH THE GAS PIPELINE

COMPO- NENT	TOTAL AVAILABLE HYDROCARBONS ¹	(without petrochemi- cals project)	(with petrochemicals project)			
		HYDROCARBONS AVAILABLE TO GAS PIPELINE	HYDROCARBONS AVAILABLE TO GAS LIQUIDS PIPELINE	HYDROCARBONS AVAILABLE TO NATURAL GAS PIPELINE		
				(liquid volume)	(gas volume)	(gross energy) ⁵
C ₁	1,879 MMCF/d ²	1,879 MMCF/d	none		1,749 MMCF/d ⁴	= 1,766 BBTU/d
C ₂	58.1 MB/d	58.1 MB/d	24.7 MB/d	33.4 MB/d	= 53 MMCF/d	= 93 BBTU/d
C ₃	23.3 MB/d	23.3 MB/d	57.6 MB/d	none	none	none
C ₄ (i)	9.4 MB/d	9.4 MB/d	none	9.4 MB/d	= 12 MMCF/d	= 9 BBTU/d
C ₄ (n)	23.3 MB/d	21.9 MB/d ³	20.3 MB/d	1.6 MB/d	= 2 MMCF/d	= 7 BBTU/d
C ₅ (i)	6.3 MB/d	.8 MB/d ³	4.2 MB/d	none	none	none
C ₅ (n)	11.7 MB/d	.2 MB/d ³	none	none	none	none
C ₆₊	10.2 MB/d	none ³	none	none	none	none
CO ₂ + N ₂		2.3MMCF/d			2 MMCF/d	
TOTAL VOLUME		2,071 MMCF/d			1,815 MMCF/d	
TOTAL ENERGY ⁵		2,291 BBTU/d				1,905 BBTU/d
GAS QUALITY ⁵		~~1,106~~ 1,086 BTU/CF				1,050 BTU/CF

1. AVAILABLE HYDROCARBONS are from Table 1, column 5.

2. 90.71 percent of 2071.

3. Available volumes, less shipments via IAPS.

4. Because 34.3 MB/d of the propane required for field fuel is not available under the B&M scenario, a BTU-equivalent (131 billion BTU per day), presumably methane, must be removed from the hydrocarbons available through the gas pipeline (130 MMCF per day).

5. Heating values are in gross or high heating value (HHV) BTU. All heating value and volumetric conversions are taken from the Gas Processors' Association tables, which we presume are equivalent to those used in the Parsons study.