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BARLOW

WAINWRIGHT SECURITIES INC.

INDUSTRY REVIEW

April 1, 1977

PETROLEUM INDUSTRY

North Slope Oil and Gas

Introduction

Realization of the enormous economic value represented by the multi-billion-barrel petroleum reserves on Alaska's North Slope is an investor paradox: even as the much-anticipated startup of Prudhoe Bay output draws increasingly near, the uncertainties of systematically attempting to assess project economics and attendant company earnings benefits have become magnified. In particular, the pricing and disposition of North Slope oil, 1 2 the determination of pipeline tariffs (and earnings), and the State of Alaska's intentions 3 regarding oil and gas taxation all remain key unknowns even at this late stage. Because important decisions affecting these and other vital issues bearing on Prudhoe Bay economics will probably be made in 1977, this *Industry Review* provides an overall perspective on these issues' status and how they might be expected to unfold in coming months, and also outlines a model for analyzing North Slope integrated earnings — and the sensitivity thereof — under conditions of uncertainty.

Summary and Conclusions

In essence, the results of this analysis can be summarized with seven major observations.

(1) Construction Status. Despite a number of concerns that developed in 1976 regarding the integrity of the pipeline welding and other aspects of this massive construction project, essentially on-time completion of the entire system appears reasonably well assured. While some remedial tasks and final inspections remain, the correction of all of the shortcomings that were the focus of intense investor and public attention last year appears to be proceeding well. Accordingly, actual pipeline fill should begin early in the third quarter with the first tanker shipments from Valdez at a 600,000 b/d rate due in late August. The 1.2 million b/d capacity of the transportation system should be reached by year-end.

(2) West Coast Supply/Demand. Virtually all knowledgable and interested observers agree that, with a buildup of Prudhoe Bay production to 1.2 million b/d, a substantial surplus of domestic crude oil will develop in P.A.D. District V. Projections of the excess generally range from 300,000-600,000 b/d, reflecting differing expectations for refined product demand growth, other West Coast production, and the level of crude oil and refined product imports. At this juncture, U.S.-Flag vessels operating via the Panama Canal will probably be the principal means of alleviating the West Coast surplus, pending the availability of one or more proposed pipeline systems to transport the oil eastward out of P.A.D. District V. Augmentation of the existing U.S.-Flag fleet with vessels currently under construction and with subsidized U.S.-built vessels now operating in foreign service should provide sufficient capacity to handle the anticipated surplus over the short term. For political reasons, it appears that the alternative of exchanging North Slope oil with Japan for Middle East imports to the Gulf Coast and eastern U.S. ports will become an option only if the surplus becomes so large that it forces a shutting in of Prudhoe Bay production.

(3) Crude Oil Pricing Policy. The pricing of North Slope oil will be decided by the FEA (subject to approval by Congress) via a rulemaking proceeding that is now underway. At recent public hearings on the matter, the FEA received comments on a variety of proposals, ranging from allowing Alaskan oil to compete freely with imported oil in the U.S. marketplace to imposing a controlled price related to the upper tier price of a comparable West Coast crude grade. Pending the Carter Administration's North Slope pricing recommendation to Congress (which is due by April 15, 1977), the reasonable possibilities for North Slope pricing probably range from an upper tier landed West Coast price (adjusted for possible benefits from including Prudhoe Bay oil in the U.S. composite calculation) to a price competitive with imported oil. On this basis, our analysis of a number of the subtleties involved in applying the provisions of the *Energy Policy and Conservation Act (EPCA)* to the pricing of North Slope oil suggests a possible range of landed prices in Long Beach in early 1978 of $11.79 to $13.90 per barrel.

Finally, a review of the FEA's recent Notice of Inquiry suggests that the agency fully realizes the need to reconcile its entitlements treatment of North Slope oil with its findings as to the desired price level.

(4) Alaskan Taxation. In what has seemingly become an annual event, the Alaskan legislature is deliberating on yet another set of oil and gas tax proposals, raising anew the question of whether the oil industry and investors can reasonably expect a fair, workable, and, most importantly, stable tax regime to ultimately emerge in Alaska. While little support appears to exist for the radical excess value (windfall) tax of a year ago, a consensus has apparently formed on the necessity for a major overhaul of the state's production tax and corporate income tax. At this juncture, with hearings having just taken place and the possibility that

substantial legislative revision of the tax initiatives will follow, it is somewhat premature to gauge their impact on North Slope earnings. Moreover, with legislative leaders showing every intention of sticking with a mid-April adjournment date for the current session, it is conceivable that little in the way of new petroleum taxes will be enacted this year. This is particularly true given the integral relationship of the pricing of North Slope oil and the level of the TAPS tariff themselves major unknowns to the taxation question.

(5) Pipeline Tariff Determination. Recent regulatory developments in the pipeline industry (i.e., the ICC's decision in the Williams Brothers Pipe Line Company rate case) have (a) provided new insights into the Commission's current regulatory procedures, and (b) raised major questions about the appropriateness of conventional industry and ICC practices regarding the setting of pipeline tariffs. In all likelihood, resolution of the considerable uncertainty surrounding the tariff-setting process for TAPS will be an extended affair, the outcome of which appears to rest on the convergence of a major rate case involving the State of Alaska, and Ex Parte No. 308, the ICC's own rulemaking proceeding. Our review of the complex issues involved here, especially the ICC's ratemaking approach in the WBPL rate case, points towards an eventual tariff structure for TAPS that probably will be lower than has generally been anticipated by (a) the oil companies, (b) the investment community, and (c) the FEA. This conclusion is particularly noteworthy because of the importance of the level of the TAPS tariff in the overall economics of North Slope oil.

(6) Production Economics. The focal point of this *Industry Review* is a computer model the writers have developed for analyzing North Slope integrated earnings. Among other things, the model takes into account the effect of different markets of destination on the profitability of North Slope oil. Table 1 summarizes projections for 1980 unit producing profits by market under two basic price cases.

Table 1

Unit Producing Profits by Market of Destination – 1980
($ Per barrel)

	Crude Oil Price	
Market	Case I	Case II
Japan	$3.32	
Puget Sound	3.59	$3.02
San Francisco	3.51	2.88
L.A./Long Beach	3.53	2.93
Houston	3.10	2.35
Chicago	3.45	2.60

Case I: World price.
Case II: Controlled upper tier price.

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(7) Company Earnings. Finally, Table 2 presents our earnings expectations for each of the major reserve owners in the Prudhoe Bay field for selected years under specified price and pipeline tariff assumptions.

Table 2

North Slope Earnings
Modified ICC Basis Tariff Treatment – 10% Return on Valuation ? (equity or total inv.
(In millions except per share)

	1977		1978		1979		1980	
	Case I	Case II	Case I	Case II	Case I	Case II	Case I	Case II
Arco								
Total	$184.1	$160.8	$301.0	$236.4	$343.2	$291.3	$447.8	$379.0
Per share	$1.59	$1.39	$2.60	$2.04	$2.96	$2.52	$3.87	$3.27
BP								
Total	$ 65.9	$37.0	$522.5	$446.2	$473.7	$394.7	$624.8	$518.9
Per share	$ 0.17	$0.10	$1.35	$1.16	$1.23	$1.02	$1.62	$1.34
Exxon								
Total	$178.4	$154.3	$287.2	$219.0	$331.8	$274.8	$432.0	$359.1
Per share	$0.40	$0.34	$0.64	$0.49	$0.74	$0.61	$0.96	$0.80
Mobil								
Total	$ 31.6	$ 29.3	$ 38.9	$ 32.5	$ 43.4	$ 38.5	$ 54.7	$ 48.5
Per share	$0.30	$0.28	$0.37	$0.31	$0.41	$0.36	$0.52	$0.46
Phillips								
Total	$ 16.4	$ 14.0	$ 30.0	$ 23.2	$ 34.0	$ 28.5	$ 44.3	$ 37.4
Per share	0.21	$0.18	$0.39	$0.30	$0.44	$0.37	$0.58	$0.49
Socal								
Total	$ 3.6	$ 2.6	$ 9.9	$ 7.3	$ 11.3	$ 9.2	$ 14.9	$ 12.3
Per share	$0.02	$0.02	$0.06	$0.04	$0.07	$0.05	$0.09	$0.07
Sohio								
Total	$218.3	$122.6	$895.6	$748.3	$793.6	$641.2	$972.9	$795.3
Per share	$5.34	$3.00	$14.88	$12.43	$13.16	$10.63	$15.90	$13.00

Case I: World price.
Case II: Upper tier controlled price.

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Taps Construction and Field Development Progress

In contrast to so many other aspects of the North Slope project which have been characterized by little or no lessening of uncertainties as the date of scheduled startup approaches, essentially on-time completion of the 1.2 million b/d pipeline system and Prudhoe Bay field complex has become progressively more assured with each passing month.

Pipeline Construction. Notwithstanding the series of press accounts in mid-1976 which strongly suggested the possibility of further delays in completing the project due to welding and management problems, additional support for such a pessimistic view has not materialized. All but 27 of the 3,955 incidents of faulty girth welds or inadequate and/or fraudulent records of same have been corrected and it appears that these few remaining problems can be corrected in the spring. Meanwhile, yet another audit of the X-ray inspection procedures for girth welds is being conducted by a Chicago accounting firm as a follow-up measure to the earlier review by Arthur Anderson and Company. Results of this audit are due by early spring. In a separate but related matter, Congressional accusations that there are also substantial shortcomings in the double jointing welding that was performed under controlled shop conditions appear to be largely without merit.* The final independent check involving all welding is being conducted in conjunction with the "as built" survey, which is a reconciliation by a third party contractor of the system's final physical configuration with the specifications required by state and Federal inspectors. This task is now about 50% complete and at last report has not uncovered any major new discrepancies. Accordingly, the welding aspects of the project seem to be under control, subject to the findings of the ongoing audit and the completed "as built" survey.

As of late February 1977, the pipeline itself was 98.0% complete. Aside from cleaning up and performing the final backfilling, grading, and revegetation along the pipeline route, the other tasks that are still incomplete include (1) insulating some 45 miles of pipe, (2) hydrostatic testing of the remaining 160 miles of the system, and (3) miscellaneous tasks related to completion of the initial group of pump stations (Numbers 1,3,4,8, and 10).** The insulating task is not critical to an on-time completion of the initial system. Also, the final phase of hydrostatic testing, which is a critical path in the completion of the initial system, will begin as soon as permitted by the Interior Department inspectors. Finally, the pump stations were 95% complete as of early February 1977, and are only slightly behind plan. In an effort to simplify its management functions and to consolidate efforts to complete the remaining tasks as much as possible, Alyeska has awarded contracts to only two contractors for the 1977 season to complete the above tasks.

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* *Alyeska has been unable to match X-rays for 10 welds out of a total of some 41,753.*

** *In addition, pump stations Numbers 6,9, and 12 will be brought on later in 1977 to reach throughput of 1.2 million b/d by November 1, 1977.*

Finally, it should be noted that Alyeska has a total of some 1,900 "noncompliance reports" (NCR's) outstanding in this project which also will ultimately need to be resolved. These involve various faults or deviations from the specifications for the system which have been uncovered by either the state or Federal inspectors. The degree of seriousness of these items varies widely, ranging from either waiverable or readily correctable problems with inadequate animal crossings to more serious faults such as insufficient burial depths at some river crossings for the pipeline. At this stage, both the state and Federal inspectors believe that there are no outstanding NCR's involving questions of the integrity of the pipeline. While the diffuse nature of these problems makes it very difficult to draw a meaningful overall conclusion, our recent reviews of the situation with both Federal and state authorities suggests the identified problems are manageable and unlikely to result in a major slippage in the completion date for the initial system.

Valdez Terminal. Again, as of late February, the terminal facilities were 86% complete or about six percentage points behind plan, which strongly suggests that this part of the project remains the critical path for the entire system. The most important single task at Valdez has been construction of the electrical power station. At this point, the power plant is being brought onstream in stages, with the first of three boilers now firing up and the other two due to follow shortly. Regarding the two tanker berths required for initial loading, berth number 4 is now complete and berth number 5 should be completed on or about May 1, only slightly behind target. As to other important elements of the terminal project, hydrostatic testing of all the major fluid piping systems has been completed, and 17 of the 18 tanks required through Phase I have been finished and checked. Basically, all that remains are (1) completion of berth number 3, (2) repair of some relatively minor damage resulting from an accident involving the 18th storage tank, (3) startup and final testing of the terminal control system, and (4) final grading, clean-up, and demobilization. Current plans call for completion of all of tasks (2) and (3) by June and tasks (1) and (4) (which are not critical) by September. Accordingly, the terminal should probably be ready to accept crude oil by late spring.

Expansion to 1.6 Million b/d. Until 1976, Sohio and other TAPS participants had indicated that expansion of the pipeline's capacity from 1.2 to 1.6 million b/d would proceed as rapidly as physically possible. Since that time, however, there has been ample incentive for North Slope reserve holders not to proceed as quickly with plans for full exploitation of the main (Sadlerochit) reservoir's potential. Such incentive has come from the likelihood of a (1) West Coast surplus of crude oil in 1978-1979 together with some uncertainty about exports as an alternative (even on a temporary basis), and the imponderable of U.S. pricing policy for (2) Prudhoe oil. In addition, while it may be only a technicality that could be readily modified, the present TAPS ownership agreement provides that the system must be operated at the 1.2 million b/d capacity level for nine months before any member can propose a further expansion.*

Once a decision to expand is made, one full winter will be required for installation of the refrigerated foundation at pump station number two. Since it now appears that the decision point has already passed for achieving 1.6 million b/d of pipeline capacity in 1979, our best estimate for the onstream date of this new capacity is late 1980.

** From Sohio's standpoint, the apparent benefit of higher production from such a proposal is at least partly offset by the likelihood that its TAPS ownership interest would be increased (with a meaningful negative cash flow effect initially) and by the marketing problems that the additional oil will present prior to the availability of pipeline outlets.*

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Costs. The Prudhoe Bay project has had so many significant boosts in the estimates of its total development costs that there is little or no credibility in Alyeska's most recent indication that construction is now proceeding well within the $7.7 billion budget and that the last of the increases may already have been seen. Nevertheless, Alyeska's experience with labor productivity and other factors over the past two years should probably contribute to a modest increase in the final construction cost number.

Moreover, if there is a final overrun in the net cost of the 1.2 million b/d system, it could be offset by the proceeds obtained from sale of the surplus equipment used in its construction. The equipment's original book value totaled about $800 million. If the resale value of this hardware is 30%-40%, a cost adjustment on the order of $240-$320 million would result.

As to the cost of expanding the pipeline's throughput from 1.2 to 1.6 million b/d, Alyeska is adhering to its estimate revision of $675 million made some 12 months ago. In this case, we are optimistic that this estimate will be only moderately exceeded (i.e., approximately $700 million) due to certain cost savings associated with design changes in the system. Specifically, tankage requirements at Valdez have been reduced from 32 to 22; a fifth loading berth has been eliminated; and plans for a cooling system for the oil at Valdez have been dropped. In regard to a further expansion of TAPS to 2.0 million b/d, the only official guidance is the estimate of $855 million to do so in one step. However, this estimate was formulated in 1975 and has not been updated. Accordingly, it appears that this figure is too low.

Field Development. Development of the main Prudhoe Bay reservoir itself remains on schedule. A total of 119 wells have now been drilled. Of these, enough have been completed to comfortably provide 600,000 b/d of production when the pipeline becomes available. In addition, BP and Arco/Exxon have each nearly completed two gathering centers (flow stations). Accordingly, the availability of 1.2 million b/d of productive capacity by November 1977 appears reasonably well assured. Finally, both BP and Arco/Exxon are proceeding with construction of their third gathering center (flow station) with completion planned for 1978, once again making completion of pipeline activities the critical path in expanding the system's output.

West Coast Supply/Demand – 1978 and Beyond

This section updates a previous analysis of the long-term outlook for West Coast petroleum supply and demand which appeared in out *Industry Review – North Slope Oil and Gas* of May 1975. In addition, it provides a basis for viewing the possible profit implications for various North Slope producers of a likely West Coast crude surplus which is examined later in this report.

In recent months, considerable attention has been focused on the outlook for West Coast supply/demand after the startup of North Slope production. As a starting point for reviewing supply/demand balances, Table 3 summarizes historical District V product demand, refining, and crude production data.

Table 3

P.A.D. District V Supply/Demand
(Thousands of b/d)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	12 Months Ending October 1976
Product demand	1,562	1,666	1,741	1,863	1,945	1,952	2,031	2,159	2,324	2,192	2,211	2,336
Crude runs	1,362	1,392	1,452	1,567	1,658	1,676	1,742	1,858	1,976	1,869	1,937	2,032
Crude production	899	986	1,073	1,217	1,238	1,254	1,203	1,150	1,122	1,081	1,076	1,061
Net crude deficit	463	406	379	350	420	422	539	708	854	788	861	971

Source: Bureau of Mines data.

As the above data shows, P.A.D. District V has long been crude short. From 1965-1970, the deficit remained relatively stable as increases in local production approximately matched both the growth in demand for refined products and the overall rise in crude oil runs. Thereafter, and until late 1973, the shortfall widened substantially; during the period, District V production declined while demand for refined products continued to grow. Following a drastic curtailment in demand due to the economic recession in the aftermath of the Arab oil embargo, the 1975 crude shortfall improved only slightly from the 1973 level. For the most recent 12-month period for which data is available, however, it appears that resumed growth in demand for refined products and essentially flat District V production are translating into a renewed expansion of the West Coast crude deficit.

Virtually all of the deficits in Table 3 have been filled by imported crude oil. Table 4 provides a breakdown of these foreign sources and shows changes that have occurred in the mix since the upheaval of October 1973. In general, it can be seen that Canadian imports have been declining steadily (on both a relative and absolute basis, reflecting that country's policy of increased domestic utilization of its own production). Three other major sources (Indonesia, Saudi Arabia, and the United Arab Emirates) have all grown by significant percentages since 1974. Of these areas, Indonesia has experienced the largest absolute increase in shipments to District V. This trend reflects the particular appropriateness of the low-sulfur characteristics of Indonesian oil for the West Coast market. As discussed later, these factors are likely to dictate a continuing role for Indonesian oil in West Coast refineries, even after major new supplies of Alaskan oil become available.

(See Table 4 on following page)

Table 4

Imports of Foreign Crude and Refined Products
(Thousands of b/d)

	1973	1974	1975	12 Mos. Ending October 1976
Canada	241.7	188.9	163.6	116.0
Equador	44.0	39.0	52.7	40.4
Indonesia	188.7	249.5	295.3	438.2
Iran	37.7	139.2	105.2	116.4
Saudi Arabia	231.6	95.4	95.6	175.6
United Arab Emirates	30.7	23.5	49.9	73.6
Other	35.9	40.4	89.3	114.5+
Total crude	810.3	775.9	851.6	1,074.7
Refined products	59.6	51.4	30.8	25.8
Total crude and refined products	869.9	827.3	882.4	1,100.5

Source: Bureau of Mines data.

Until the Arab oil embargo, it was generally expected that a growth rate in West Coast demand for liquid hydrocarbons somewhat above an estimated 4.5%-5.0% for the overall U.S., combined with projected declines in existing Californian and Alaskan production, would result in sufficient growth of the crude deficit from the level shown in Table 3 so as to enable Prudhoe Bay output to be fully absorbed in the region by simply backing out imports of comparable quality foreign oil. However, as discussed in our May 1975 *Industry Review*, the sharp crude price increases after 1973 necessitated a complete revision of projections to reflect both the supply and demand elasticity effects of rising hydrocarbon prices on West Coast balances over the intermediate and longer term. In essence, our earlier analysis pointed to a P.A.D. District V crude oil surplus in 1980 on the order of 685,000 b/d under assumptions of (1) a modest 2% growth in product demand and (2) North Slope output of 2.0 million b/d. Now with the benefit of the additional information gained during the past 20 months, it is evident that a number of the key assumptions underlying West Coast supply/demand analyses have once again undergone further significant change. On the one hand, it is apparent that something less than 2.0 million b/d of North Slope output is currently assured from existing Sadlerochit, Kuparuk, and Lisburne reserves. Alternatively, a better capability now exists for estimating the effects of higher prices on refined product demand growth and on production prospects for remaining P.A.D. District V output ex Prudhoe Bay.

A number of new and updated West Coast supply/demand analyses completed by various companies and Government agencies concerned with the situation have recently been published by the Senate Interior Committee (now the Energy and Natural Resources Committee).* In general, these projections reflect more optimistic assessments of District V production prospects as a result of (1) the opening of production from the Naval Petroleum Reserve at Elk Hills, (2) improved economics for enhanced recovery projects (principally thermal methods), and (3) renewed offshore development activities. Also, it is important to note that virtually all of these analyses incorporate relatively conservative demand growth expectations, which average 3%-4% annually for all products. Among the various refined products, residual and other fuel oils are expected to grow considerably faster due to expected shortages of natural gas supplies projected for West Coast electric utilities.** Table 5 provides a summary of the net crude oil surpluses projected in each of these analyses.

Cost higher or lower than North Slope oil?

Table 5

Projected P.A.D. District V Surplus Through 1985
(Thousands of b/d)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
FEA		600		900-1,100					700-1,300
Arco		400	400	400	400	550	600	650	700
Exxon	200	600	500	700	600	600	800	900	1,000
Kitimat	(815)	(199)	68	359	523	638	553	518	434
Sohio		300-600				600-800			
Socal	300	350	600					750	
Union Oil	250	550	550						

( ) Denotes deficit.

Source: U.S. Senate Interior Committee.

Summary of responses to joint committee questionnaire on Potential Problems Associated with the Delivery of Crude Oil from Alaska's North Slope, Committee on Interior and Insular Affairs, November 1976.

**Reflecting the growing need of West Coast utilities such as Pacific Lighting, The Pace Company, consultant to Sohio, has projected that 1980 District V residual fuel consumption will increase 26% above the 1977 level versus only a 12% gain in consumption of all petroleum products. In our view, this projection may prove too conservative because of undue optimism about a flattening of the decline of natural gas supplies prior to 1980 in response to higher prices.*

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In view of the numerous variables which affect the West Coast supply/demand balance (i.e., the rate of buildup in Prudhoe Bay production, the rate of growth in product demand, the average decline rate of existing production, and the possible magnitude of new P.A.D District V production ex the North Slope, to name a few), clearly the nature of the problem is anything but deterministic. In fact, the relatively wide range of estimated deficits shown in Table 5 can be attributed to various combinations of fairly small differences in assumptions applied to the large base figures for overall supply and demand. This phenomenon of compounding of small differences is better demonstrated by the data and assumptions underlying individual forecasts which are summarized in Appendix A. Given the nature of the situation, it is not our intention to offer yet another refinement of projections of future West Coast supply/demand balances into the early 1980's. Rather the approach here has been to present the above conclusions by various knowledgeable and interested parties along with some additional observations in order to identify and focus on a "base case" expectation for a likely West Coast crude surplus.

Our review of the assumptions and analyses associated with the forecasts shown in Table 5 indicates that Socal's projections provide a credible and useful set of conclusions upon which to build a "base case" for examining the economics of North Slope crude oil movements. In particular, as a major West Coast crude oil producer, the company presumably has good firsthand knowledge of the factors affecting trends in both existing and new production in the region. Similarly, as a long-established refiner-marketer in District V, Socal probably has the best insight into likely future trends in demand for key refined products. In this connection, Socal's current refinery expansion program assures that it will have the ability to be the largest West Coast processor of North Slope oil and a dominant supplier of fuel oils to a burgeoning market of utilities converting over from natural gas.

As a point of reference then, the assumptions upon which Socal's analysis rests are outlined below.

(1) Overall refined product demand growth will average slightly under 3 1/2% during 1976-1985, with demand for low-sulfur fuel oils growing quite rapidly and demand for gasoline being slow to 1980 and flat from 1980 to 1985.

(2) District V refining capacity will expand at a more moderate rate than is currently suggested by FEA projections* as shown below.

	FEA Estimates	Socal Estimates
	(Thousands of b/d)	
1980	2,938	2,786
1979	2,906	2,756
1978	2,874	2,739
1977	2,835	2,709
1976	2,588	2,305

*See the FEA's *Trends in Refinery Capacity and Utilization*, June 1976.

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(3) P.A.D. District V crude oil production – ex Prudhoe Bay – will remain approximately unchanged at 1,050,000 b/d during 1978-1980. This level includes estimated contributions of 200,000-270,000 b/d from Elk Hills and 50,000-80,000 b/d from new fields and projects offshore California (Carpenteria, Dos Cuadras, Santa Clara, Santa Ynez).

(4) Prudhoe Bay production will begin at 600,000 b/d in mid-1977, build up to 1.2 million b/d within one year, and expand further to 1.5-1.6 million b/d by 1980.

Although the projections above are stated in terms of "crude barrel balances," it is important to note that the post-1977 West Coast supply problem in reality will be much more complicated due to differences in quality considerations between North Slope oils and the various other crudes it will be competing against in the marketplace. To provide additional perspective on the question of differing product yields and specifications, Table 6 compares some of the salient characteristics of Prudhoe Bay oil with representative Saudi, California, and Indonesian crude oils.

Table 6

Distillation Yields
Prudhoe Bay vs. Other Crudes

	Prudhoe Bay	Saudi Arabian	Coastal California	Indonesian (Minas)	Indonesian (Ataka)
Light straight run gasoline	3.1%	8.2%	3.2%	3.2%	7.0%
Reformer feed	15.5	10.4	19.3	6.1	33.0
Jet fuel	9.4	17.1	9.4	9.8	21.0
Diesel cut	12.6	12.0	11.0	12.4	20.0
Gasoil	36.3	32.2	32.6	43.5	16.0
Residuum	21.7	16.0	22.5	24.4	1.0
API gravity	27.4°	34.0°	27.8°	35.3°	43.2°
Sulfur content	0.95%	1.8%	1.5%	0.07%	0.07%

Source: *Oil and Gas Journal.*

Given the higher product cuts at the low end of the barrel for Prudhoe vs. the other oils, it is apparent that the displacement of either Saudi or California oil beyond certain levels now anticipated in the plants of West Coast refineries will tend to skew the product mix from District V refineries toward meaningfully greater quantities of heavy gasoil and residual products – unless additional cracking facilities are installed to expand West Coast capacity for handling Prudhoe Bay crudes.* Conversely, if North Slope oil displaces low-sulfur Indonesian imports (which are predominantly Minas crude), substantial new facilities would

**The following results of an FEA survey provide perhaps the best publicly available indication of the ability of District V refiners to handle North Slope oil, considering only those conversions and expansions now under way:*

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be required to reduce the sulfur content of products, particularly heavy fuel oil, to enable refiners to supply a product that meets current specifications of local air pollution authorities. Because of the major capital investment required in both of these cases, these options for alleviating a surplus of North Slope oil are only long-term alternatives which are very much subject to as yet undecided Federal policies on the pricing and entitlements treatment of North Slope oils vis-à-vis other sources.

Footnote continued from previous page:

1978 Potential Distribution of North Slope
and Foreign Imports in P.A.D. V

Refinery (a)	1975 Capacity MB/D	1978 Alaska North Slope	1978 Foreign Imports	1975 Imports (b)	1975 Sweet Imports
Los Angeles					
Union	108	0- 50	10- 20	45	8
Arco ✓	182	70-100	30- 50	65	32
Socal	230	130-190	50- 90	150	141
Shell	96	20- 35	5- 10	21	3
Mobil	124	25- 30	8- 10	14	8
Gulf	52	10- 25	10- 15	20	5
Douglass	47	5- 25	5- 10	11	6
Texas	75	15- 20	15- 20	15	16
Powerine	44	0- 5	10- 15	20	10
Subtotal	958	275-480	143-240	361	229
San Francisco					
Exxon ✓	88	70- 74	0- 5	45	3
Socal	190	120-176	30- 42	50	24
Shell	100	30- 40	0- 5	21	2
Toscopetro	110	0- 30	15- 20	33	1
Union	111	0- 19	0- 15	N/A	N/A
Subtotal	599	220-339	45- 87	149	30
Puget Sound					
Arco ✓	96	96- 98	--	94	43
Mobil	71	10- 35	70	48	48
Shell	91	0- 15	70	71	63
Texaco	78	0- 2	70	76	59
Subtotal	336	106-150	210	289	213
Grand total	1,893	601-969	398-537	799	472

(a) Includes only those refineries likely to utilize North Slope crude.
(b) Port of Entry only. These are incomplete crude quality reports but very close to total foreign imports reports which are proprietary.
N/A Not available.

Source: Summary of responses to joint committee questionnaire on Potential Problems Associated with the Delivery of Crude Oil from Alaska's North Slope.

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For the shorter term, based on the considerations just outlined, Union Oil, another company with excellent perspective on the situation, has questioned whether projections by some of the other interested parties sufficiently recognize the product yield characteristics of North Slope oil relative to (1) the crudes it will be seeking to displace and (2) the particular needs of the West Coast market. The company points out that the introduction of relatively low gravity (27°) North Slope oil into a market that already is being supplied with substantial quantities of locally produced heavy oil is likely to cause some dislocations. In fact, notwithstanding the previously mentioned expectations of soaring electric utility demand for fuel oils as a result of shrinking natural gas supplies, Union representatives believe the West Coast refining of North Slope crude could exacerbate an already difficult situation by providing even greater quantities of fuel oils with sulfur contents that are unacceptably high for major portions of the West Coast market.* If the present entitlements disincentives and restrictions on exports of residual fuel oil (and on exports of heavy California crudes) are continued, Union believes that a significant surplus of this product will develop by late decade, with additional adverse effects on the demand for Prudhoe Bay and/or comparable quality California heavy crude oils. Chart I summarizes the company's projections of this surplus.

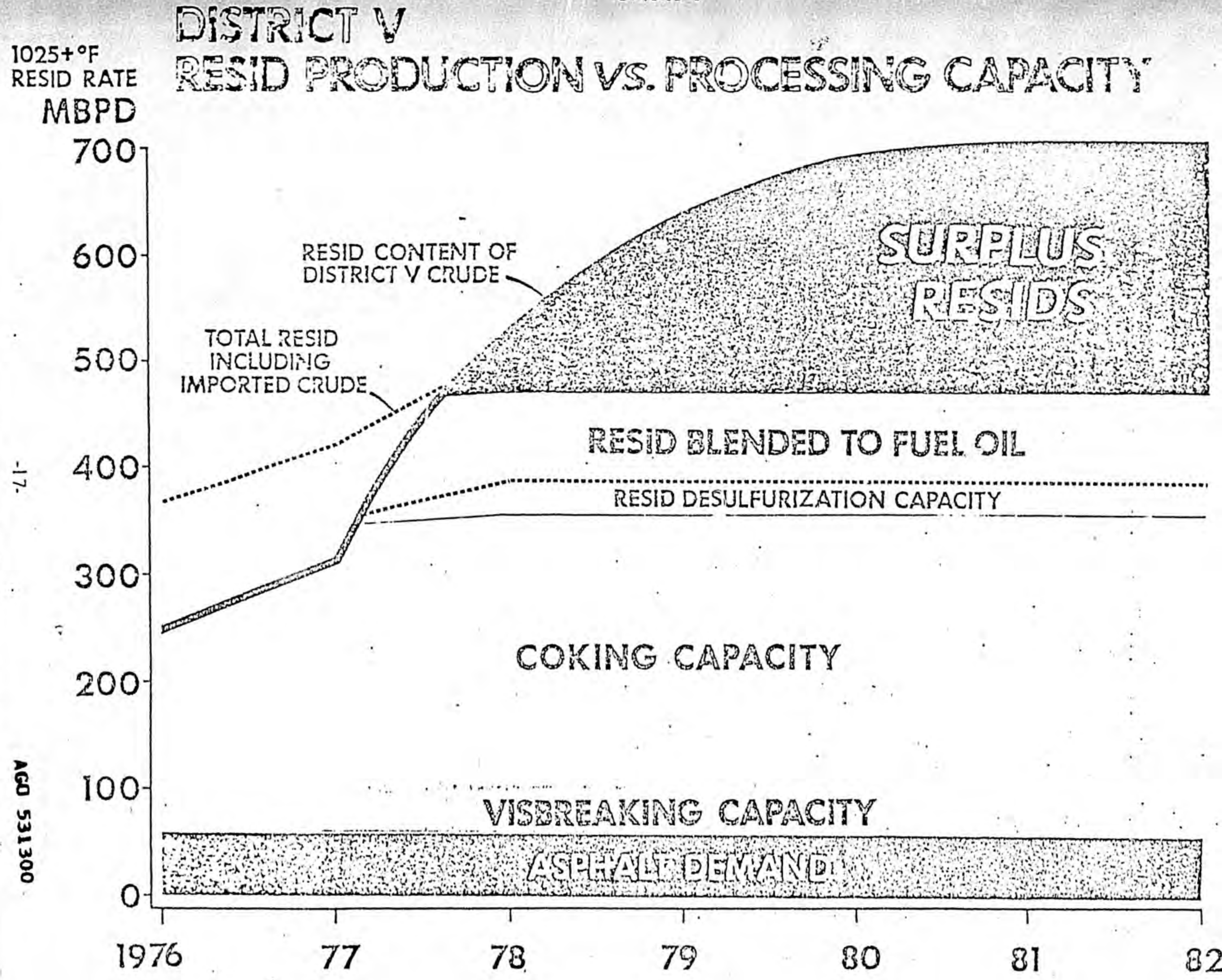
Socal generally agrees with Union's analysis, though its degree of concern seems to be somewhat more muted, perhaps reflecting the company's unusually strong capability of processing and marketing the output from these crudes. In any case, both concur that the above considerations dictate a continuing role for certain minimum levels of imported crude under the present and likely 1978-1980 configuration of West Coast refineries. Socal's 1978-1980 projections assume industry utilization of some 400,000-600,000 b/d of imports, consisting primarily of Indonesian crude with some Saudi oil also being used to meet lube oil requirements.

Having reviewed some of the physical constraints on the consumption of North Slope oil in District V, it is necessary to note that certain economic factors will also have a direct bearing on the plans of refiners to handle this oil, especially the pricing and entitlements treatment of North Slope output, both of which will be discussed in more detail later.

(See Chart I on following page)

**Without desulfurization, North Slope crude, which has a 0.95% sulfur content, yields residual fuel with 1.75% sulfur. The inappropriateness of such a fuel for California needs is well emphasized by the recent agreement between the State Air Resources Board and Socal Edison, whereby the utility will begin immediate conversion of all 40 of its oil-fired electric generating plants in the South Coast Air Basin to burn 0.25% sulfur instead of 0.5% sulfur fuel oil.*

CHART I



Source: Union Oil Company of California

At this juncture, there are still no definitive answers to the questions posed by Union and other West Coast refiners. However, given the situation's obvious uncertainties, *it is clear that, in formulating various scenarios for disposition of Prudhoe Bay crude oil, some allowance should be made for the possibility of even higher levels of required movements of North Slope crude out of District V than might otherwise be suggested by strict calculation of barrel balances.** Having now added this caveat to the "base case" expectation that the West Coast crude surplus will approximate 300,000 b/d for 1978 and 350,000 b/d for 1979, it is helpful to review the various means of moving such excess Alaskan oil to other markets. The major alternatives are outlined on page 19, along with some indication of the potential volumes involved and the time frames within which they could become effective.

For additional perspective, Map I generally outlines the routes of the various proposals listed and provides indications of the expected transportation costs associated with each.

A few other observations about the various alternatives listed below are in order. As to the interim means available for handling excess North Slope oil, the practicalities and politics of the situation are likely to dictate the use of a combination of measures. Initially, the bulk of the excesses likely will be moved by unsubsidized *Jones Act* U.S.-Flag vessels through the Panama Canal, with perhaps some relatively small quantities also moving via a reversed Four Corners pipeline and rail tank cars, economics permitting. Several observers have concluded that there will probably be enough flexibility in the U.S.-Flag fleet to accommodate the expected West Coast surplus with certain adjustments. Sohio's analyses indicate that sufficient unsubsidized U.S.-Flag capacity will exist to move about 250,000 b/d of crude oil through the Panama Canal beginning in late 1977 over and above the tanker requirements for North Slope oil consumed on the West Coast. This estimate is reasonably in line with those of the Overseas Shipholding Group, Inc. (OSG) (an independent U.S.-Flag operator with a meaningful amount of Alaskan-suited tanker capacity) and the Maritime Administration (MARAD), which has recently conducted a detailed analysis of the availability of tanker transportation at the request of the FEA. With the completion of ships still under construction, these observers also generally agree that U.S.-Flag vessels available for Panama Canal movements would rise to approximately 400,000 b/d in 1979.

As the MARAD and OSG analyses point out, it is impossible to be completely definitive as to tanker capacity for Panama Canal movements since there may be significant tradeoffs with various transportation configurations. For example, while generally the Canal can only accommodate fully-loaded vessels of up to 60,000 dwt, certain of OSG's specially designed 90,000 dwt vessels can traverse it partly loaded. Thus, tanker capacity through the Canal

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**In fact, in developing a preliminary marketing model for the distribution of North Slope oil in the early years (see Table 16) we have used the midpoint of the FEA data on refiner's indications of possible North Slope crude runs in each West Coast refinery adjusted for a small expansion of Exxon's capacity at San Francisco. This approach suggests 1978, 1979, and 1980 movements of North Slope crude out of P.A.D. District V might approximate 395,000 b/d, 395,000 b/d, and 613,000 b/d, respectively.*

Interim Solutions	Indicated Volume (b/d)	Available
(1) U.S.-Flag tanker shipments to P.A.D. Districts I-IV via the Panama Canal.	250,000 325,000 400,000	1977 1978 1979
(2) Transshipment eastward out of P.A.D. District V via railroad tank cars.	40,000-50,000	1978
(3) Four Corners pipeline.	30,000-40,000	1977-1978
(4) Exchanges of crude oil with Canada and Mexico.	Uncertain and limited.	1978
(5) Export to Japan via foreign-flag tankers.	Essentially unlimited by physical capacity considerations.	1977
(6) Shutting in excess North Slope production	? N/A	N/A

Longer Term Solutions

(1) Sohio and Exxon's LATEX pipeline from Long Beach to Midland, Texas.	500,000 1,000,000	1980 1982 (Phase II)
(2) Northern Tier Pipeline system from Port Angeles, Washington to Clearbrook Minnesota.	600,000 800,000-1,200,000	Post-1980 (Phase I) Post-1980 (Phases II-III)
(3) Trans-Provincial Pipeline system from Kitimat, B.C., tieing into existing pipelines at Edmonton, Alberta, Canada.	300,000 350,000 430,000 650,000	April 1979 1980 1982 Ultimate
(4) Reversal of Trans Mountain Pipeline.	165,000 350,000	Late 1978 (yo-yo) 1980 (full reversal)
(5) Central American pipeline system across Guatemala.	600,000 1,200,000-1,600,000	?
(6) Retrofitting existing District V and/or Northern Tier refineries to run additional North Slope oil.	–	Post-1980

N/A Not Applicable.

(See Map I on following page)

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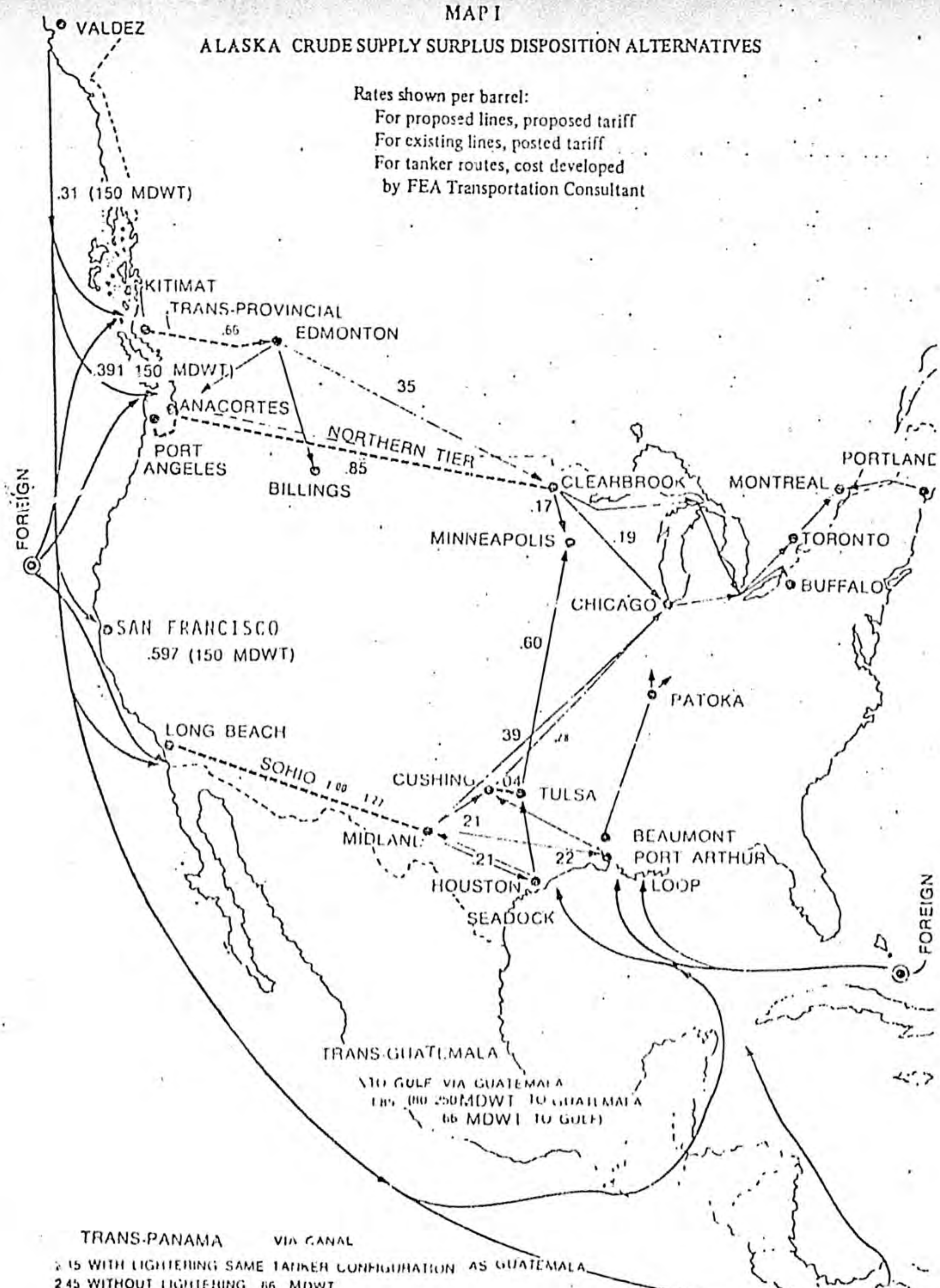
MAP I

ALASKA CRUDE SUPPLY SURPLUS DISPOSITION ALTERNATIVES

Rates shown per barrel:
For proposed lines, proposed tariff
For existing lines, posted tariff
For tanker routes, cost developed
by FEA Transportation Consultant



Source: FEA.

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could depend on whether such vessels are actually used in this mode or are shuttled fully-loaded to the Canal's western terminus where the oil could be lightered to handy-sized tankers (50,000 dwt and smaller). Since there is some uncertainty as to the exact amount of waste or inefficiency associated with each particular mode, final predictions of volumes should not be viewed as deterministic.

Thus, in view of the magnitude of the possible surplus already outlined and allowing for less than optimal utilization of nominal *Jones Act* capacity,* the West Coast excesses could probably build up to the point where there will be a need for either (1) additional Panama Canal shipments using subsidized U.S.-built vessels now operating in foreign service (subject to the obtaining of appropriate *Jones Act* waivers), or (2) exchange of North Slope oil or comparable California oils with Japan or Canada using either U.S.-or foreign-flag vessels in return for oil delivered to other U.S. destinations (P.A.D. Districts I-IV).

As to the first option, studies by both independent shipowners and the Maritime Administration indicate that numerous possibilities exist for returning U.S.-Flag tankers now in subsidized international service to domestic operation. One such study points to the need for 900,000-1,000,000 tons of such vessels to handle a surplus on the order of 500,000 b/d. The use of these vessels would require waivers under the *Jones Act* which most observers believe would be readily obtainable.** Beyond compliance with these legal provisions, the principal factor controlling the return of such vessels to domestic service will be the availability of attractive tanker rates. However, at the $1.75 per barrel charge for movement from Long Beach to Houston contemplated (in the discussion on production economics which follows), the adequacy of the return to the shipowners will probably not be a problem.

Regarding the second option of handling West Coast excesses beyond those that can be transported by *Jones Act* ships, an exchange of oil with another country offers the possibility of certain savings in transportation costs in the case where North Slope oil is priced based on the value of equivalent imported crude. For example, Table 7 shows that the Valdez netbacks associated with North Slope crude movements to Japan and Houston are $12.13 and $11.52 per barrel, respectively. The $0.61 per barrel difference essentially represents transportation costs that could be saved from the shorter transportation routes for moving Alaskan oil to Japan and Saudi oil to the U.S. Gulf Coast.

As a final note, because of the leadtimes involved, none of the pipeline projects (except possibly the Four Corners and Trans Mountain lines) or refinery modifications will likely be

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**The OSG analysis places the wasteage associated with traversing the Panama Canal at 10%-15%.*

***The MARAD Study states: "In the case of these tankers which receive operating-differential subsidies, eligibility for domestic service could be obtained by foregoing subsidy assistance for the period of domestic employment. This would assure compliance with Section 605(a) of the Merchant Marine Act of 1936. The issue of construction-differential subsidy repayment during periods of domestic employment, while more complex, is possible under Section 506 of the Act."*

available before 1979 at the earliest. A detailed discussion of each of these projects is beyond the scope of this report, but the analysis which follows does consider wellhead profitability on North Slope crude movements to the Gulf Coast and Chicago, respectively, utilizing the LATEX and Trans Mountain pipeline systems as the representative southern and northern routes.

Crude Pricing

The pricing of North Slope oil is another key unknown at this time – a situation partly attributable to key pending Government policy decisions. The following excerpt from the Joint Conference Committee report of the 1975 *Energy Policy and Conservation Act (EPCA)* outlines the basic provisions of the crude pricing legislation applicable to Alaskan North Slope oil production.

> On April 15, 1977, the President is required to submit to the Congress a report on the adequacy of the then current weighted average price to provide positive incentives for the development of Alaska oil production without reducing ceiling prices and production incentives in the lower forty-eight states.
>
> If the President finds that the then current maximum weighted average price is not adequate to provide such positive incentive, he may submit to the Congress a proposal, in the form of an amendment to the pricing regulation, to exclude up to 2 million barrels per day of Alaska production flowing through the Trans-Alaskan pipeline referred to in paragraph 2(a) in subsection (g) from the calculation of the actual weighted average price. Such a proposal must include a proposed ceiling price or prices for such excluded Alaska production, the average of which cannot exceed the highest actual weighted average first sale price permitted under the regulation for significant volumes of any other classification of domestic oil. Such proposal must be supported by findings justifying the level of such ceiling price or prices.* Disapproval of the proposal by either House within 15 days under expedited procedures would prevent such an amendment to the regulations from taking effect.
>
> If such an amendment is disapproved, the President can send an additional proposal for exempting Alaska production within 30 days of the initial disapproval. If either proposal becomes effective, beginning on January 1, 1978, and at no sooner than 90 day intervals thereafter, the President may submit to the Congress, proposals to modify the ceiling price or prices established in his initial Alaska exemption proposal. If either House disapproves the proposal within 15 days, the proposed modification may not become effective.

• While the FEA has been conducting certain preliminary staff analyses and public hearings connected with meeting the above requirements, it currently appears that much additional work remains before the new Administration is prepared to forward its findings and recommendations to Congress regarding the pricing policies for North Slope oil. Given the

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**The conference report further suggests that a detailed examination of the actual costs of Prudhoe Bay production as well as an analysis of the project's expected rate of return would be the required basis for justifying a proposal to exclude Alaskan production from the calculation of the U.S. composite price. This could provide fertile ground for debate as to (1) the proper costs to be included in the analysis, (2) the appropriate methodology of calculating investment returns, and (3) the "fair and equitable" return to be allowed.*

significance of crude prices in an assessment of company earnings prospects, this section identifies and discusses the major factors under consideration in formulating a workable policy and also offers some tentative views concerning possible courses of action to be adopted. While these latter judgments will form the basis for our subsequent profitability analysis, our approach to modeling North Slope economics is flexibly structured so that it facilitates the incorporation of any meaningful change from the anticipated pricing policies that may emerge from the Administration's recommendations to Congress in mid-April.

At the time of the *EPCA's* enactment, we discussed its provisions with a member of the Senate Interior Committee. He indicated that the legislative architects deemed the term "first sale" to refer to the oil's wellhead price. Although this intent is not well-specified in the *EPCA* conference committee report, the *Congressional Record* of December 17, 1975 indicates quite clearly that Congress intended the first sale price for purposes of calculating the U.S. composite price to be "the wellhead price or the nearest equivalent prior to the time the oil has entered the common carrier Alaskan pipeline." Notwithstanding this seemingly well-defined legislative intent, regarding the term "first sale" as it applies to North Slope pricing policy matters, it appears that the FEA is analyzing several different approaches to applying the *EPCA's* provisions to North Slope oil. Essentially, the following alternatives will probably receive the greatest consideration:

(1) Allowing North Slope oil to compete freely with the world price of import alternatives in the markets to which it is shipped. If the wellhead value of North Slope oil exceeds the composite U.S. selling price, it should be excluded from calculation of the composite in order to remove any disincentives to lower-48 production.

(2) Placing North Slope oil in the upper tier category under *EPCA* with the West Coast landed price defined as the point of pricing regulation and include this oil in the calculation of the U.S. composite price.*

(3) Providing a ceiling wellhead price for North Slope crude oil which is equal to the maximum composite price under the current price regulations. In December 1976, the composite ceiling price was $8.24 per barrel. In August 1977, it will be $8.79 per barrel and presumably will continue to escalate thereafter at a 10% annual through May 1979.

**In its recent Notice of Inquiry on Alaskan North Slope pricing, the FEA has actually suggested using the refiner's average acquisition cost for upper tier oil ($11.[illegible]4 in December 1976). Due to the quality difference between North Slope oil and the average crude run in West Coast refineries, we believe a case using the upper tier price for oil comparable to Prudhoe Bay crude more appropriately brackets the range of possibilities.*

Alternative 1: The full ramifications of this alternative are potentially complex but they deserve discussion because they provide considerable insight into the potential dynamics of U.S. oil pricing in general, particularly under conditions of high import dependence. In order to understand the issues involved, it is useful to begin with an examination of the laid-in equivalent price of a competing imported oil (i.e., Saudi Arabian Light crude) adjusted for the difference in quality. Table 7 presents the calculation of these various laid-in prices for a variety of end markets and the resulting Valdez netback values associated with each market.

It is evident from Table 7, that if the pricing of Alaskan oil is allowed to be determined solely by the price of imported oil, a variety of imputed Valdez netback values would result due to the differences in transportation costs involved in moving the oil to each market. Accordingly, the question arises whether producers will be allowed, or able, to discriminate in the pricing of Alaskan oil among various end markets. To the extent that pricing is discriminatory, the Valdez netback values calculated in Table 7 would become the appropriate price inputs for any assessment of unit profitability by market of destination. On the other hand, if non-discrimination in pricing at Valdez becomes necessary, either for antitrust or competitive reasons, a considerably more complex, dynamic economic pricing model for North Slope oil would result.

In this connection, it is interesting to note that company respondents to a Senate Interior Committee survey do not fully agree on the question of whether multiple Valdez netbacks are feasible. Sohio's view is that:

> Sales east of the Rockies are expected to be made at or about the same price as on the West Coast (i.e., the landed foreign sour crude price) and the seller will have to absorb the extra transportation costs. . . Thus, for those sales, the wellhead realization will be lower than for sales on the West Coast by the amount of the extra transportation costs involved which can't be recovered in the market.

By contrast, all of the other companies surveyed expect a uniform price at Valdez to prevail.

The implications of a non-discriminatory pricing situation are detailed in our May 1975 *Industry Review – North Slope Oil and Gas* and will not be repeated here. In general, however, our previous discussion indicated that as long as North Slope production is only meeting District V crude deficits, the expected Valdez netback would be that associated with Long Beach, or $12.62 per barrel under the assumptions used in constructing Table 7. However, as shipments to more distant markets commence, and if the pricing of sales at Valdez does not discriminate as to destination, Houston would become the relevant market for pricing and would tend to depress the Valdez price of all Prudhoe oil to (1) $11.52 per barrel by our current calculations (assuming availability of Sohio's LATEX pipeline) or (2) $11.12 per barrel using U.S.-Flag tankers through the Panama Canal. Therefore, under non-discriminatory pricing at Valdez, the producers' selection of more distant markets to move incremental barrels of Alaskan oil will have to take account of the effect of such movements on the overall price of Alaskan oil.

(See Table 7 on following page)

Table 7

Valdez Netbacks by Market of Destination
($ Per barrel)

Market of Destination	Yokohama/Tokyo	Puget Sound	San Francisco	L.A./Long Beach	Houston	N.T./Chicago
34° Arabian Light selling price (FOB Ras Tanura)	$12.09	$12.09	$12.09	$12.09	$12.09	$12.09
Ocean transportation (at current AFRA) (a)	0.62	1.12	1.23	1.17	1.42	1.39
Terminal charge at port of entry	0.10	0.10	0.10	0.10	0.10	0.10
Crude oil import fee	--	0.21	0.21	0.21	0.21	0.21
St. James. La. to Chicago (via Capline)	--	--	--	--	--	0.30
Landed crude oil price	$12.81	$13.52	$13.63	$13.57	$13.82	$14.09
Quality adjustment (b)	(0.25)	(0.25)	(0.25)	(0.25)	(0.25)	(0.25)
Prudhoe Bay equivalent price	$12.56	$13.27	$13.38	$13.32	$13.57	$13.84
Transportation costs to Valdez:						
Pipeline					(1.35)(c)	(1.31)(d)
Tanker	(0.43)	(0.50)	(0.80)	(0.70)	(0.70)	(0.50)
Valdez netback	$12.13	$12.77	$12.58	$12.62	$11.52(f)	$12.03(g)

(a) The movements to the West Coast ports have been computed at Worldscale 56 for LR-2's (80,000-159,999 dwt), except for San Francisco, which because of a size limitation to 50,000 dwt, has been computed at the LR-2 rate of Worldscale 56 to L.A./Long Beach, with an additional five Worldscale points added to reflect a "double-porting" movement to San Francisco with a partial load (i.e., a 100,000 dwt tanker carrying a half load). The cost of ocean transportation to the Gulf Coast ports assumes a movement from Ras Tanura to the Freeport (Bahamas) transshipment terminal in a VLCC at Worldscale 49, and from Freeport to the Gulf Coast in an LR-1 at Worldscale 81. Transshipment costs are estimated at 10¢/bbl. The movement to Yokohama/Tokyo is assumed to be in a VLCC at Worldscale 49.

(b) Reflects net adjustment for higher gravity of Arabian Light and lower sulfur content of Prudhoe Bay crude.

(c) Cost from Long Beach-Houston via Sohio's proposed LATEX pipeline system to Midland and thence via connecting pipeline to Houston.

(d) Cost from Puget Sound-Chicago via proposed yo-yo of the Trans Mountain pipeline system to Edmonton, Alberta and thence via the Interprovincial and Lakehead pipeline systems to Chicago. Under a batch reversal configuration, the total pipeline cost to Chicago would be 98¢/bbl., with a corresponding increase in the Valdez netback to $12.36/bbl.

(f) Assuming a movement by Jones Act tanker between Long Beach and Houston via the Panama Canal, at an incremental cost of $1.75/bbl., the Valdez netback would be reduced to $11.12 per barrel.

(g) For Northern Tier refiners, who will have no other alternative once Canadian exports cease, the cost of crude will be equal to the delivered (controlled) price of Alaskan oil on the West Coast plus the pipeline tariff to move it to the refinery destination.

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Under perfectly competitive conditions, there is little doubt that the non-discriminatory pricing situation would prevail. However, not much oil will actually be sold at Valdez to third parties, but will be moved by the producers to appropriate markets where it can compete with similar imported oils. Toward this end, both Sohio and Exxon, who have the bulk of the anticipated West Coast surplus, have entered into transportation arrangements that have relatively high fixed-cost components, and that therefore should tend to discourage aggressive discounting to gain market share in District V.* Accordingly, we do not find the competitive market arguments favoring a fully non-discriminatory pricing mechanism particularly persuasive.

The antitrust implications of such a pricing mechanism are not altogether clear, but available evidence suggests that discriminatory pricing, albeit with the possibility of moderate discounting, is the more likely situation. Sohio believes that as long as its pricing policy does not discriminate between buyers in the *final markets* and it does not conspire with Exxon or others in setting its prices for third-party sales, it will be in compliance with current antitrust laws. While some observers believe that certain provisions of *The Clayton Act* could be interpreted as prohibiting such a pricing approach, there apparently is no case law to support this view. Moreover, further support for Sohio's expectation of multiple Valdez and wellhead netbacks is provided by the fact that a similar situation has existed in the Cook Inlet for a number of years.

7

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The FEA has indicated that it is fully aware of the need to consider the implications of entitlements treatment for the prices that refiners will actually be willing to pay for North Slope. Under the FEA's interpretation of current regulations, it appears that Prudhoe Bay crude would be classified as upper tier for purposes of the entitlements program. Thus, in order to avoid the disincentive of an entitlements purchase obligation for a refiner of North Slope oil, the FEA recognizes that it will be necessary to afford this crude a stripper or imported oil status if it is determined that its pricing at imported oil levels is desired.

Alternative 2: This possibility envisions applying the upper tier ceiling price to the landed price of Alaskan oil at a prescribed West Coast location. This would approximate the upper tier price of Signal Hill 27° gravity crude, which, after the recent 65¢ per barrel of cumulative rollbacks, is currently frozen at $9.91 per barrel. The regulated wellhead price of Alaskan oil could then be calculated by subtracting estimated transportation costs. *In this case, price regulation under EPCA would result in a meaningful revenue reduction for both producers and the State of Alaska.* As a result, there is the question (which the FEA must address in its rulemaking) whether this price level would provide sufficient positive incentive for developing other northern Alaskan reserves.** For example, initially (i.e., mid-1977) a $9.91 per barrel

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**It has been estimated that of the $1.75 per barrel of incremental transportation costs to move oil from Long Beach to Houston, perhaps 25¢ per barrel is variable (principally bunkers and crew wages). Thus, discounting would probably approximate this figure.*

***As mentioned previously, this approach would appear to contradict the intent of Congress in passing EPCA. Nevertheless, it appears that the currently ongoing FEA analysis is likely exploring such a policy option with the idea of recommending a change if it is shown to be a preferable pricing alternative.*

allowed price at Long Beach less a 70¢ per barrel tanker charge and $4.70 of pipeline tariff results in a wellhead price of $4.51 per barrel versus the $6.42 wellhead value associated with pricing tied to the landed value of Saudi Arabian oil in Houston under the first alternative described.

Actually, however, if this option were adopted and the low wellhead value of North Slope were also included in the U.S. composite calculation, it appears likely that within a fairly short period of time there could be a partial offset in the form of resumed upward revisions in the FEA's upper tier crude oil ceiling prices. In fact, our preliminary analysis would suggest that the FEA price schedule for domestic oil prices published in the spring of 1976 could be resumed by early 1978. On this basis, the appropriate upper tier value would become $11.79 per barrel by January 1, 1978, averaging $10.85 per barrel during the second half of 1977.*

Since Alaskan oil would be sold at a price other than the cost of imports, provisions for partial entitlements treatment would likely be required to equalize the costs for refiners running varying proportions of Alaskan crude. This possibility could further complicate the pricing of Alaskan oil, To understand the situation, it is necessary to consider the value of North Slope oil from the viewpoint of the refiner whose alternative is imported oil for which he receives the right to sell a full entitlement. Thus, if a West Coast refiner is required to purchase a partial entitlement for each barrel of Prudhoe crude used, he would pay a maximum price equal to the refinery gate price of equivalent imported oil *less* the value of the partial entitlement. By one account, the inclusion of North Slope oil in the U.S. composite is likely to reduce the average realized U.S. price sufficiently to increase the value of such a partial entitlement to approximately $3.00 per barrel. Thus, for example, a Long Beach refiner considering North Slope oil might well be only willing to pay $10.32 ($13.32 landed value of equivalent Saudi crude less $3.00) for North Slope oil at the refinery gate.**

**For example, if 1.2 million b/d of North Slope oil is priced at an upper tier level of $11.79 for crude movements as outlined in Table 16, the weighted average wellhead price of North Slope oil would be $6.26 per barrel, well below the then prevailing statutory price ceiling of $9.06 per barrel. These calculations are based on a $4.23 per barrel tariff, the computation of which is discussed in the North Slope Profitability Model section.*

***A graphic illustration of a similar situation in which entitlements treatment has become the determining factor in crude oil pricing is provided by the current West Coast heavy oil situation. Arco testimony submitted last fall shows that because of the entitlements treatment of lower tier heavy oil, the latter is actually more expensive to the refiner than imported Saudi crude as shown below:*

	Wilmington Heavy		*Saudi Light*
Lower tier ceiling price	*$ 4.53*	*Landed price*	*$12.65*
Gravity adjustment	*0.50*		
Reqd. entitlement purch.	*7.85*		
Avg. entitlement credit	*(2.80)*	*Avg. entitlement credit*	*(2.80)*
Refiner's cost	*$10.08*	*Refiner's cost*	*$ 9.85*
Cost disadvantage	*$0.23*		

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upping ¢/barrel

As will be discussed further in our section on *Alaskan Taxation*, because such a pricing alternative is under consideration (with or without the entitlements twist just outlined), the State of Alaska is considering new tax legislation in an attempt to protect its oil revenues at the wellhead by making certain adjustments to its production tax structure.

Alternative 3: The principal purpose of adopting the option of pricing North Slope oil at the composite price level would be to avoid the future possibility of Alaskan oil prices becoming a disincentive for lower-48 production, should the gap between upper tier and imported oil widen to the point where Prudhoe Bay oil would be priced higher at the wellhead than the composite price. In putting forth this alternative, the FEA indicated that the entitlements treatment of the oil would be either the same as imported crude or as a separate tier if that should become necessary. Under this scheme, Alaskan North Slope oil would escalate in line with the rate allowed by *EPCA* (and modified by *ECPA*) for the composite price through May 1979.

As another part of its preliminary staff analysis in preparing to meet the Administration's April 15, 1977 reporting requirement to Congress, the FEA engaged an outside consultant (Mortada International) to review the economics of the entire North Slope project. The purpose of this contract was *not* to present a set of final recommendations on the pricing of North Slope oil, but to develop an objective analytical framework for drawing some price judgements. Some of the consultant's more important observations are summarized below:

- Equitable prices of Prudhoe Bay crude (in 1976 dollars) at Valdez fall between $11.50 and $12.40 per barrel, to be adjusted quarterly for inflation.

- Pricing at Valdez provides a built-in incentive for developing the more speculative Kuparuk and Lisburne Oil Pools.

- Pricing at Valdez circumvents the uncertainty in tariff rates.

- Equitable prices of Prudhoe Bay crude at the wellhead fall in the range of $7.00-$7.90 per barrel (1976 dollars), to be adjusted quarterly for inflation.

- The study did not address itself to the implications on pricing of any surplus of crude on the West Coast.

While these observations would seem to suggest that an analytical basis is being established for North Slope prices essentially in line with, or only slightly below the world price of equivalent imported oil, it is probably risky to place too much weight on the influence of one outside consultant's findings on the outcome of the FEA's final ruling.* In fact, it is increasingly evident that this study is but one step in the rulemaking process; the others include public hearings by the FEA on the matter as well as possible supplementary hearings by the Senate Energy and Natural Resources Committee to inform its members of the issues. Clearly then, pricing expectations must be formulated with caution.

**As pointed out at the recent FEA hearing by a legal consultant to the State of Alaska, the methodology in the Mortada study for establishing the tariff structure does not consider the implications of the recent Williams Brothers Pipe Line rate case and the related matter of the ICC Ex Parte No. 308 proceeding.*

Furthermore, while the State of Alaska and the North Slope producers as expected have argued at these hearings for a price based on the value of the import alternative, some observers believe that the FEA will be under considerable pressure from other sources to adopt an alternative similar to the second one outlined above and, concomitantly, to structure its entitlements program so as to equalize the costs of North Slope oil delivered to the West Coast and the Gulf Coast/Midwest. To this end, one proposal calls for adopting discriminatory entitlement treatment for North Slope oil. For example, West Coast refiners obtaining Prudhoe crude at an upper tier price might be required to purchase a partial entitlement for each barrel processed, whereas the District I-IV refiners using the same oil (which would have a $1.75 per barrel higher delivered cost via the Panama Canal) could be granted either an exemption from an entitlements purchase obligation or a right to sell a partial entitlement. Theoretically, by adjusting the magnitudes of the entitlement awards and purchase obligations of these parties, the actual costs of North Slope oil in the various markets could be evened out.

modified Tussing

The consideration of such an approach is probably partly based on the following section from the *Trans-Alaska Pipeline Authorization Act of 1973:*

Equitable Allocation of North Slope Crude Oil

> Sec. 410. The Congress declares that the crude oil on the North Slope of Alaska is an important part of the Nation's oil resources, and that the benefits of such crude oil should be equitably shared, directly or indirectly, by all regions of the country. The President shall use any authority he may have to insure an equitable allocation of available North Slope and other crude oil resources and petroleum products among all regions and all of the several States.

There are now well-established precedents for the use of the FEA's entitlements program to even out the costs of petroleum products between various regions of the country. These involve the complex regulations applicable to domestic refiners and importers of residual fuel oil that have undergone a number of actual and proposed modifications and, most recently, the adoption of a similar program to provide price relief to northeastern consumers of No. 2 heating oil by spreading the cost to consumers in other parts of the U.S. Given these precedents and the legislative provision cited above, the push for a similar treatment of Alaskan oil may politically be very difficult to dismiss.

In making its final decision on Alaskan oil pricing, the FEA will probably be guided by three basic considerations: (1) a need to provide sufficient incentive to maximize Prudhoe Bay production; (2) a desire to provide equitable distribution of the benefits of that oil among various regions; and (3) a desire to create added pricing flexibility for other U.S. production. Considering all the factors discussed above, it will probably be difficult for the FEA to select an alternative that fully accommodates all three objectives. Thus, in view of the uncertainty that will continue to characterize the pricing of North Slope oil until the FEA completes its rulemaking process in April, our economic analysis which follows presents two scenarios. Case I assumes a world price for Alaskan oil netted back to Valdez on a basis that permits discrimination as to final destinations for the crude. Case II calls for an upper tier realization for Prudhoe Bay oil on the West Coast with a return to the FEA's initial pricing schedule for upper tier oil by January 1, 1978, as a result of inclusion of Alaskan oil in the U.S. composite. The range of reasonable possibilities appears to be well bracketed by these two cases without detailed analysis of numerous other possibilities that we consider to be less probable and certainly more speculative.

not even considering State proposal

No need to wait for tariff if net back to Valdez rather than WA

Alaskan Taxation — "We're Albertans, Too!"

Alaska's Governor Jay Hammond recently introduced his Administration's proposed oil and gas taxation package at a news conference. In doing so, he defined what constitutes Alaska's fair share of the revenues from development of oil and gas resources on state lands, and thus provided yet another perspective on a matter of critical concern to the oil companies operating in Alaska:

> ... we must keep in mind that these nonrenewable resources will be developed only once and that the revenues produced will have to serve us not only for today but as a savings account for future Alaskans.

Hammond's statement can also be interpreted as a political rationalization of a proposed legislative program designed to add some $200 million a year to the state's coffers by 1985. Be that as it may, the latest state action raises anew the question of whether the oil industry and investors can reasonably expect a fair, workable, and, most importantly, stable tax regime to ultimately emerge in Alaska. In other words, will compromise replace confrontation?

Prior to 1976, Alaska had exhibited a disquieting ability to affect radical changes in oil taxation whenever its prospective oil revenues appeared threatened (the 1972 tax package, since modified), or when an imminent general fund budget crisis so dictated (the 1975 ad valorem tax on in-place oil and gas reserves). Today, largely thanks to its OPEC brethren, the state no longer need worry about generating sufficient tax receipts from Prudhoe Bay to fund its current and envisioned budget outlays; instead, the focus of tax policy has shifted to devising means whereby the state can extract its "fair share" of the economic rents created by OPEC's pricing power in order to provide a continuing legacy for the current, as well as future, generation of Alaskans. The shift had begun in 1976, with the so-called Huber tax proposals.* The proposals called for a steep excess value (windfall) tax on the difference between the West Coast landed value of North Slope oil and a state-determined value ($7.00 per barrel, initially).** If the Huber tax package had been enacted, total Government take from the Prudhoe Bay field would have risen to a level not unlike that in some OPEC countries.

Gosh + Ted

**The Huber tax proposals were named after their principal sponsor, State Senator John Huber, Chairman of the Alaskan Senate's Special Committee on Taxation and Revenue in 1976.*

***Besides the excess value surtax, the tax package submitted by the Special Committee on Taxation and Revenue would have: (1) raised the production tax on North Slope oil from 7.8% to 12.6% (with concomitant modifications to the cents-per-barrel minimum tax); and (2) modified the corporate income tax structure, under the guise of a net properties proceeds tax, to ensure that oil and gas income derived from Alaska would be separately accounted for in the determination of corporate income tax liability. An outline and discussion of these proposals appears in our Special Report – Alaskan Tax Proposals of January 22, 1976.*

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The Alaskan legislature finally tabled the Huber proposals on the adjournment of the 1976 session, reflecting its belief that such legislation was ill-timed (partly due to an intensive and effective lobbying campaign waged by a curious amalgam of interests). At that point, with an eye towards formulating a new set of oil taxation initiatives, the Administration initiated a revenue and taxation study by its Department of Revenue in cooperation with the Legislative Council's Interim Committee on Oil and Gas Leasing and Tax Policies.

Early in the 1977 legislative session, the Interim Committee submitted two new tax bills constructed along the lines of the less onerous features of the Huber package (i.e., the production tax and net properties proceeds tax proposals). The Committee did not attempt to resurrect the excess value tax concept of 1976. Then, in early March, Governor Hammond presented his Administration's oil and gas taxation package to the legislature. (The Hammond proposals are based on a massive study released by the Department of Revenue in February 1977 entitled *Alaska's Oil and Gas Tax Structure: A Study with Recommendations for Improvement.* As stated in the foreward, the study's basic objective was to suggest a *stable* tax system sufficient to meet Alaska's revenue *needs* and respond to changes in economic conditions, Federal policies, and industry operations.) Specifically, Hammond's package comprises five essential features:

(1) The corporate income tax would be replaced with a franchise tax based on income which corporations report to shareholders rather than the current system which is tied to taxable Federal income.

(2) The property tax, now assessed on pipelines and exploration and production facilities, would be extended to cover oil tankers, LNG facilities, refineries, and petrochemical plants. The Administration's property tax proposal would also tax pipelines based on their economic value instead of depreciated historical cost.

(3) A simplified oil production tax (with a maximum rate of 10%) would be substituted for the current stair-step mechanism in order to properly reflect the considerable differences in economic factors governing production operations in various parts of the state. In addition, to protect tax revenues from erosion due to unpredictable pricing actions at the Federal level and from possible corporate profit-shifting activities, a "floor" (initially set at 75¢ per barrel) would be established under the oil production tax at a level approximating the "free market" (OPEC) value of the oil. The floor would escalate over time in line with the GNP deflator. Natural gas would be similarly treated. The current percent-of-value tax rate of 4% would be raised to 10% and, for the first time, a cents-per-Mcf minimum tax (initially set at 6.4¢ per Mcf) would be established. The latter figure is not subject to escalation as is the case with oil.

(4) Because of a larger-than-anticipated budget surplus in fiscal 1977, the assessment rate for the oil and gas reserves tax would be reduced from 20 mills to 12 mills. If TAPS is not transporting at least 600,000 b/d on October 1, 1977, however, the full 20 mill rate would become payable on the January 1, 1977 assessment.

(5) The contribution to the permanent fund from royalties and lease bonuses would be raised from the current level of 25% (as provided by a constitutional amendment approved by Alaskan voters in November 1976) to 75% in fiscal 1979 and 100% thereafter.

Compared to the legislature's own proposals to modify the stair-step production tax schedule now in effect and to adopt a direct accounting system for measuring Alaskan oil and gas income, Hammond's objectives in these areas incorporate some novel twists.

First, Hammond has recommended that an Economic Limit Factor (ELF) concept replace the current production tax, which establishes higher tax rates (cents-per-barrel minimums) according to the productivity of individual wells. In essence, ELF is the ratio of the production rate at the true economic limit to the current production rate, and would be used to reduce the severance tax rate as output declines toward the economic limit. This is accomplished by multiplying a basic tax rate (10%) times one minus ELF to produce a smooth continuous series of tax rates which scales the effective tax rate down to zero at the economic limit. Relative to the existing production tax mechanism, ELF's advantage is that it can be tied to the actual economic characteristics of a given property -- without resorting to multiple tax rates tied to averaged well production per producing property. To provide downside protection to production tax revenues, an initial "floor" price of $7.50 per barrel would be established, with escalation in subsequent periods tied to the GNP deflator. Under the ELF method, the cents-per-barrel minimum tax for any given year is calculated by multiplying the product of 10% plus the "floor" price by the ELF.

In sum, ELF would bring about a rather hefty increase in the overall level of the production tax. Despite some positive structural features, it would also inevitably cause a squeeze on company producing margins should the FEA set a ceiling price for North Slope oil below that which equates at the wellhead to the state's "floor" price.* (A high pipeline tariff would generate the same result.) This situation is akin to the position of the oil industry in Canada in 1974-1975, when the provinces and the federal government clashed over shares in revenues to the detriment of producer margins and eventually drilling activity and investment spending. In the U.S., the situation is one more example of the growing assertion of states' rights in the field of energy -- with the oil industry caught seemingly helpless as pawns in the struggle. Moreover, in Alaska's quest to maximize its take from presently proven North Slope reserves, the state appears to be disregarding the disincentive it is creating for the development of more marginal reserves, such as those in the Kuparuk and Lisburne formations. It may be recalled that *EPCA* sanctioned *positive* incentives for the development of Alaskan North Slope oil.

**The Department of Revenue had also considered a "lost value" surtax designed to offset lost royalties resulting from oil prices below the "floor" price. However, the surtax was not included in the final legislative proposal.*

The second novel twist of the Hammond package is its proposal to install a franchise tax in lieu of the corporate income tax in an attempt to alleviate certain alleged deficiencies in the present income tax structure as regards multi-jurisdictional corporations. These deficiencies relate to (1) the definition of the taxable base, and (2) the formula for apportionment of taxable income provided in the *Uniform Division of Income for Tax Purposes Act (UDITPA)*. Alaska, as a member of the Multistate Tax Compact (that currently comprises 21 states), is subject to the UDITPA's three-factor formula for apportioning business income to a state.* However, the Hammond Administration is recommending** that the corporate income tax be separated from the Federal definition of taxable income (with all its exemptions, incentives, and credits). To do so, a tax base measured by book income would be substituted for the Federal taxable income base. Then, a franchise tax (determined at the rate imposed under existing Alaskan statute) would be applied in lieu of the normal corporate income tax on a corporation's pretax income as reported to shareholders.

To overcome the problem of the sales factor in the current apportionment formula (which relates to the fact that the value of petroleum products is assigned to the state where the final destination sale is made, not to the state where the petroleum is produced), an extraction factor would be substituted for the sales factor. The extraction factor would relate a corporation's oil and gas production in Alaska to its worldwide production. If such an origin-oriented factor had been applied in 1975 to the 13 largest oil corporations operating in Alaska, it would have added more than $50 million to the state's apportioned taxable income. Moreover, Zeifman and Ainsworth estimated that their franchise tax proposal would have increased corporate income taxes paid by oil and gas corporations in 1975 more than four-fold – from $3.5 million to $14.4 million. Also, by modifying the apportionment formula, instead of developing a direct accounting method for Alaskan oil and gas income (as contemplated in HB 145), the total taxable income of the unitary business could continue to be combined, thus avoiding the complexities associated with attempting to disentangle intercompany transactions.

From Alaska's standpoint, passage of the franchise tax would undoubtedly resolve some glaring deficiencies in its current income tax treatment. Also, it would ensure that the North Slope producers pay something resembling the 9.4% nominal tax rate imposed on domestic (Alaskan) corporations doing business only in the state – versus the 2%-3% rate that

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**The three factors are property, payroll, and sales. The formula assumes that these factors equally contribute to the generation of income by a corporation and that the total income of a corporate business can be divided among the taxing states in proportion to each state's share of property, payroll, and sales. Under the Uniform Act, Alaska's taxable income is determined by multiplying the taxpayer's entire taxable income by a fraction which comprises the ratios of Alaska-to-total property, payroll, and sales.*

***The Administration's recommendation relied on the findings of two consultants (Zeifman and Ainsworth) contained in a study entitled "The Taxation of the Petroleum Industry Under Alaska's Corporate Income Tax."*

otherwise would apply to a multinational oil company. Unfortunately, in extending the reach of the tax collector to encompass OCS production and oil tankers, the state is probably exceeding the limits of fairness and reasonableness. While the Hammond tax package purports to close a number of existing loopholes in Alaska's current tax system, another key objective apparently is to expand permanent fund revenue. The increase would provide for future generations of Alaskans, and simultaneously allow the general fund budget to keep pace with population growth and inflation. In essence, the oil industry is being "asked" to fund a $200 million per year balancing wheel.

Table 8, from the Department of Revenue study cited previously shows the impressive buildup of general and permanent fund balances that will occur through fiscal 1985 even without the proposed tax changes. Petroleum revenues have been calculated using a world oil price assumption. Costs of moving the state capital from Juneau to Willow (between Fairbanks and Anchorage) and expenditures on the North Slope Haul Road have been excluded on the expenditure side.

Table 8

General and Permanent Fund
Finances with Arctic Gas Pipeline
(In millions)

	General Fund Expend.	Petro. Revenue	Non Petro. Revenue	Interest	Total Revenue	General Fund Balance	Perm. Fund Balance
FY 76	$ 616.4	$ 378.2	$292.6	$ 31.7	$ 702.5	$ 569.3	$ 0.0
FY 77	728.1	489.9	362.8	26.9	879.6	718.3	2.4
FY 78	853.8	646.6	225.8	35.0	907.4	689.7	84.7
FY 79	942.1	895.7	236.3	53.9	1,185.8	803.3	214.7
FY 80	979.5	1,079.2	256.8	68.5	1,404.5	1,063.0	380.0
FY 81	1,042.7	1,318.2	279.0	94.0	1,691.2	1,514.5	577.0
FY 82	1,111.0	1,632.8	294.3	132.8	2,059.9	2,234.4	806.1
FY 83	1,058.0	2,025.4	317.1	189.7	2,532.2	3,415.1	1,099.5
FY 84	1,086.9	2,307.6	343.2	278.0	2,928.8	4,917.3	1,439.2
FY 85	1,159.2	2,519.0	373.3	388.3	3,280.6	6,664.5	1,813.5

Source: State of Alaska, Department of Revenue.

If 100% of oil and gas royalty and bonus income is placed in the permanent fund beginning in 1980, the figure of $1.8 billion shown in Table 8 would, according to Department of Revenue projections, grow to more than $7 billion by 1985. The balance in the general fund would be about $2.5 billion, compared with general fund expenditures estimated at $1.2 billion for fiscal 1985.

At this juncture, with hearings having just taken place, and the possibility of substantial legislative revision to follow, it is somewhat premature to discern the final outcome on the latest set of tax proposals and to gauge their specific impact on North Slope earnings. However – and notwithstanding the Alaskan legislature's more conservative orientation, together with a drastically altered leadership and committee set-up in the Senate – the state will probably be concerned primarily with the timing and mechanics of how best (not whether) to obtain a portion of the economic rents it believes exists at Prudhoe Bay. Because the legislature shows every intention of sticking with a mid-April adjournment date, and given the importance of North Slope oil pricing on their deliberations, it is conceivable that little could be accomplished this year. Certainly, a delaying action would likely be in the best interest of the oil companies. Whereas the price of Alaskan oil is paramount to the state's future oil revenues, developments affecting the TAPS tariff (examined in the next section) could moderate some of the state's drive for new oil revenues, and, at the extreme, soften the margin impact of a high "floor" price under the production tax if that feature is adopted and the price of North Slope oil is set below the world level landed on the West Coast. Pending further developments, this report's profitability projections are based on three key taxation assumptions: (1) an effective 9.4% corporate income tax rate; (2) the Administration's proposed ELF production tax mechanism; and (3) a TAPS property tax based on historical cost depreciated over a 30-year period. predicts property tax won't pass !!!

Appendix B lists the results of some discounted cash flow (DCF) calculations the writers made using the net cash flows derived from TAPS and oil and gas production from the main (Sadlerochit) Prudhoe Bay reservoir. Real DCF rates of return of 10.6%, 19.1%, and 15.7% using constant (1977) dollars were calculated for TAPS, the main Prudhoe Bay field, and the combined operation, respectively. While many of the specific assumptions used are spelled out below, the DCF analysis assumed a world price for North Slope oil at Long Beach, and a TAPS tariff based on pipeline throughputs approaching 2 million b/d (which incorporates Kuparuk and Lisburne reserves as well as those in the main Prudhoe Bay field) and a return on equity approach in determining maximum allowable pipeline earnings. Relative to DCF rate of return objectives of 20%-25% set by many companies for exploration and production ventures, and actual rates of return for some of the larger North Sea fields far in excess of that, a real rate of return of just under 16% for the largest oil field ever found in North America provides an interesting perspective on the question of economic rents. Moreover, the 15.7% return would probably be depressed further by inclusion of the large investment in tankers required to move the oil to West and Gulf Coast markets, plus full consideration of the economics involved in moving surplus Alaskan oil on the West Coast to other markets.

The analysis of DCF economics also permits a revenue breakdown between the oil companies, municipal, state, and Federal governments. Table 9 shows how the pie is shared for the Prudhoe Bay field. Interestingly, the oil companies would receive less than 50% of revenues less operating costs from TAPS and oil and gas production with which to pay principal and interest to bondholders, dividends to shareholders, and for new investments. In sum, it appears that Government is the main beneficiary of Prudhoe Bay development.

In an address to a group of oil analysts on the West Coast in October 1976, U.S. Senator Ted Stevens of Alaska referred to the state's legacy at Prudhoe Bay by stating "We're Albertans, too!" Since Alaska currently has neither a tax climate nor a set of development incentives to spur new E&P outlays that even remotely resembles Alberta's system, it would seem to have a better affinity with the Indonesians. In all seriousness, the State of Alaska is at the crossroads. A willingness by the legislature and Administration to compromise on some particularly contentious features of the current tax proposals could go a long way towards establishing a tax structure conducive to a healthy investment climate for the oil industry in Alaska – and to the needed development of the state's potentially enormous petroleum and minerals resources for the benefit of the entire U.S.

(See Table 9 on following page)

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Table 9

Distribution of Prudhoe Bay Revenue Pie (a)
(In millions)

effective 48%??

Year	Total Revenues Less Oper. Costs	Property Taxes State	Property Taxes Municipalities	Royalty State	Royalty Native Fund (b)	Production Taxes	Income Taxes State	Income Taxes Federal
1976	—	$ 220						
1977	$ 1,399	270		$ 103	$ 20	$ 43	$ 33	
1978	5,446	148	$ 59	412	78	165	230	$ 1,029
1979	5,689	156	63	437	83	171	245	1,031
1980	7,085	162	68	589	112	355	340	1,513
1981	8,390	179	76	707	135	561	419	1,909
1982	8,837	187	81	827	66	590	451	2,085
1983	9,243	196	89	942		619	481	2,226
1984	9,673	203	94	994		648	521	2,408
1985	10,120	206	97	1,047		677	570	2,635
1986	10,577	202	95	1,102		707	629	2,911
1987	10,634	198	93	1,106		703	655	3,032
1988	10,384	196	94	1,072		668	658	3,045
1989	10,156	192	91	1,040		636	662	3,066
1990	9,959	186	90	1,012		603	666	3,084
1991	9,746	181	88	981		573	668	3,093
1992	9,012	175	85	885		499	631	2,920
1993	8,397	169	84	803		434	601	2,783
1994	7,849	164	80	729		377	575	2,664
1995	7,381	156	77	666		325	553	2,560
1996	6,930	148	75	604		284	526	2,432
1997	6,594	141	70	557		250	506	2,342
1998	6,206	132	67	503		212	483	2,234
1999	5,763	123	62	431		170	456	2,112
2000	5,364	114	58	388		131	431	1,995
2001	5,127	103	53	353		107	419	1,939
2002	4,856	91	46	314		80	405	1,873
2003	4,598	79	41	286		60	388	1,796
2004	4,342	66	33	253		37	371	1,718
2005	4,184	55	29	233		24	361	1,671
Totals	$213,942	$4,798	$2,038	$19,376	$494	$10,709	$13,934	$64,106

(a) Excludes Prudhoe Bay field natural gas and oil production from the Kuparuk and Lisburne Pools.

(b) Under the terms of the Alaska Native Claims Settlement Act, all lands selected by the state but which had not yet been patented to it were made subject to a two percent oil and gas royalty interest payable out of the state's one-eighth royalty interest. This provision applies until $500 million has been paid into the Fund.

Distribution of Total Revenues Less Operating Costs:

	Amount (In billions)	% of Total	
State of Alaska	$ 48.8	22.8	incl. royalties.
Municipalities	2.0	1.0	
Alaska Native Fund	0.5	0.2	
Federal Government	64.1	30.0	
Oil Companies	98.5	46.0	
Total	$213.9	100.0%	

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North Slope Profitability Model

This section integrates the analysis and conclusions of the previous three sections, and precludes the construction of earnings profiles for the major Prudhoe Bay reserve owners. Specifically, it presents the methodology and workings of a computer model the writers have developed for purposes of calculating the integrated profitability of North Slope crude oil movements. In recognition of the complex interplay of factors bearing on the economics of North Slope oil, the emphasis here is not on postulating a single deterministic solution. Since many assumptions and estimates are necessarily entailed in an undertaking of this kind, in our opinion, an appreciation of the sensitivities associated with key parameters and a framework capable of rapidly assimilating any new data that becomes available is equally as important.

Instead of deriving profitability figures for each company based on its particular circumstances, we have worked with a composite case which represents the companies' aggregate position. While such parameters as TAPS tariffs, tanker transportation charges, and markets of final destination for crude oil liftings will vary somewhat by company relative to our composite case assumptions, the resulting differences should not be sufficiently large so as to preclude the usefulness of our analysis in projecting future earnings for the North Slope producers.

lumps

Pipeline Issues and Economics

In the integrated economics of North Slope oil, TAPS simultaneously represents a significant cost and profit center. Moreover, because of important differences in the incidence of taxation on pipeline and wellhead earnings, TAPS is also a source of continuing friction between the interests of the State of Alaska (a maximum wellhead price)* and the TAPS owner companies (for a given level of costs, a maximum pipeline tariff and a correspondingly lower wellhead price). As a result, it would not be surprising if the state filed a contested rate application with the Interstate Commerce Commission (ICC), challenging the initial tariff filings of the eight TAPS owners based on their respective undivided interest in the entire

* *At a throughput rate of 1.2 million b/d, each one cent per barrel change in the pipeline tariff is the equivalent of \$4.4 million in annual revenues. Based on Alaska's current approximate 20% interest in the value of the oil at the wellhead, therefore, a one cent increase in the tariff would deprive it of \$880,000 in wellhead revenues, exclusive of any effects on state income tax receipts.*

system. Besides the investor attention likely to be focused on this action, the recently concluded Williams Brothers Pipe Line Company (WBPL) rate case* spawned a far-reaching ICC proceeding (Ex Parte No. 308, *Valuation of Common Carrier Pipelines)* now pending. Among other things, the proceeding will address the fundamental question of what constitutes a proper rate base as well as the closely related issue of what rate of return should be allowed on that base. As such, it promises to have broad ramifications for determining TAPS tariffs (and hence wellhead values) and reported pipeline earnings. To fully appreciate the scope of the issues potentially involved here, it is necessary to understand the ICC's established ratemaking procedures.

The precedent for a maximum 8% return on the value of property owned and used for common carrier purposes by crude oil pipelines was set down in *Minnelusa Oil Corp. v. Continental Pipe Line Co.* (258 ICC 41), in 1944, when the ICC held that such a return was reasonable. The Commission concluded "...that just and reasonable rates... are rates based substantially on the cost of service and fair rate of return on value." As noted in the footnote below, a similar view was taken by a majority of the Commission in the recently concluded WBPL rate case. In addition, a 1941 Consent Decree reached with the Department of Justice (to which all TAPS owners are subject, except for BP and Amerada Hess), prohibits an interstate common carrier owned by a defendant shipper-owner from earning and paying to its parent in the form of dividends or other valuable consideration more than 7% of the ICC's latest final valuation in any given year.

Historically, because the ICC's annual valuation reports have encompassed a carrier's entire inventory of property owned and used for common carrier purposes, pipeline companies have not been required to meet rate of return criteria for each pipeline segment in their system on a stand-alone basis. Since four of the TAPS owners – ARCO Pipe Line, Exxon Pipeline, Mobil Pipe Line, and Sohio Pipe Line – have other holdings besides TAPS that are currently subject to ICC regualtion, a higher return could possibly be earned on TAPS to the extent that the companies' other pipeline segments forego some potential return. Looking ahead, the sheer magnitude and visibility of TAPS, together with ongoing Congressional interest in the subject of segmentized rates, suggests that by choice or otherwise the TAPS owners will probably be shooting for a tariff within the 7% guideline on their undivided interests in the system.

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* *The WBPL rate case – the first oil pipeline rate case to come before the full Commission in over 30 years – evolved out of a protest filed by a group of shippers (mainly independent refiner-marketers) against WBPL's filing of a schedule for increased local rates and, in conjunction with Explorer Pipeline, higher joint rates on petroleum products shipments from and to certain points in the Southwest and Midwest. On reconsideration of the matter, the Commission concluded (with one notable exception) that the criteria employed by Division 2 (the Appellate Division) in judging the reasonableness of WBPL's rates were the proper ones to use in the proceeding, and that, tested by these long-standing criteria (see ensuing discussion), the overall rate level of WBPL was neither unjust nor unreasonable. In essence, a majority of the Commission embraced the principle that operating expenses plus cost of capital define a reasonable rate level. The significance of the WBPL rate case transcends this immediate finding, however, since it raised a number of substantive questions concerning the continued appropriateness of some of the ICC's established ratemaking procedures.*

In determining valuations of pipelines and railroads for ratemaking purposes, Section 19a of the *Interstate Commerce Act of 1887* specifically requires that consideration be given to cost of reproduction new,* cost of reproduction new less depreciation, and original cost. Congress did not specify the weight to be assigned each of these elements of value; rather, it left it to the ICC's discretion to determine how the weights were to be applied.

The ICC valuation process also incorporates amounts for going concern value, present value of land, present value of rights-of-way, and working capital. However, in applying its Congressional mandate, the ICC has elected to emphasize only two elements – cost of reproduction new and original cost. Its position has been that the value of property before depreciation should fall between these two elements of cost, and it has elected to weight the two based on each one's percentage relationship to the sum of the two. Hence, in an inflationary period, cost of reproduction new would receive an increasingly heavier weighting. Next, a condition percent factor** is applied to the weighted average sum of cost of reproduction new and original cost to arrive at an estimate of the cost of the property in its present condition. It is important to note that the reference to depreciation in this instance is not to an actually accrued amount; instead, physical wear and tear is estimated mathematically using condition percent factors. Although the precise manner in which final valuations are derived from among the seven components of value is not disclosed, our approach, while necessarily dependent on several assumptions, seeks to simulate the basic decision-making process followed by the ICC (see page 41 for further details).

Having reviewed established ICC valuation procedures and rate of return standards as they would apply to TAPS, and as a prelude to a discussion of some of the yet-to-be resolved issues likely to envelop TAPS in coming months, the methodology and assumptions underlying our tariff model are next presented.

**Cost of reproduction new is the estimated cost of reproducing substantially the identical property constructed in a prior period at a price level as of a subsequent date. To make this computation, the ICC relies on an analysis of construction techniques and annual and period price indices to establish cost differentials between a predetermined base period (1947) and a current period. In developing its cost of reproduction new figure, the ICC applies a prudent man condition (i.e., from hindsight, how would a prudent man have constructed the pipeline?).*

***The condition percent factor is a function of the remaining probable life of an item of property at any attained age and its total probable life at that age.*

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Assumptions for Tariff and Earnings Computation

(1) Capital cost of the 1.2 million b/d design capacity will be $7.7 billion. To expand capacity to 1.6 million b/d (Case I), incremental capital expenditures will total $700 million (vs. Alyeska's last published estimate of $675 million). A final expansion of capacity to 2 million b/d (Case II) is estimated to cost $400 million. Case I corresponds to a field development program limited to the Prudhoe Oil Pool, whereas Case II incorporates development of an additional 2 billion barrels of speculative reserves believed to exist in the Kuparuk and Lisburne Oil Pools.

(2) Capitalized interest during construction totals $1.3 billion. This amount is then amortized over a 25-year period. For any TAPS expansions which occur, capitalized interest is computed, based on an estimated expenditure and borrowing profile, until the assets are placed into service. At that point, amortization of the cumulative balance commences.

(3) Financing of the $9 billion of initial system capital costs plus capitalized interest is accomplished using 90% borrowed funds. The same debt to total capital ratio is maintained for any system expansions. Debt is retired in equal installments over a 25-year period. The maturity date on any borrowings associated with system expansions is shortened so that all borrowings are repaid as of a common date.

85/10 ?

(Sohio = 10% Arco 8.? %)

(4) Interest is assessed at the rate of 9% on the average outstanding loan balance in a given year.

(5) For rate determination, pipeline depreciation is on a straight-line basis over 35 years. For Federal and state income tax purposes, a 17½-year, sum-of-the-years-digits method is employed. Federal and state income taxes allowed for ratemaking purposes are normalized (i.e., no flow-through of deferred taxes is required). As pipeline capacity is expanded beyond the 1.2 million b/d level, a shorter depreciable life is used for assets associated with the added capacity (mainly pump stations) to conform with the remaining depreciable life of the initial system.

(6) Combined State of Alaska and municipal property taxes of 2% of assessed value are based on the actual costs of TAPS depreciated on a straight-line basis over a 30-year period. As additional pipeline facilities are added in future years, a depreciable life identical to the remaining life of the initial system is used.

not in Hammond proposal

(7) To provide for the expense of removing surface facilities at the exhaustion of the pipeline's economic life, as required in the *Stipulations for the Agreement and Grant of Right-of-Way for the Trans-Alaska Pipeline*, a reserve account has been established to meet this future contingency. Accruals into the fund are at the rate of 10.3¢ per barrel ($1 billion of estimated future cost divided by 9.7 billion barrels of crude and condensate).

(8) Operating costs of the line at a 1.2 million b/d capacity level (1978) amount to approximately 40¢ per barrel. This figure is subsequently inflated at 5% per annum until throughput begins to decline, at which point provision is made for a tapering off of variable operating costs. On completion of the expansion of line capacity to 1.6 million b/d (assumed to occur in 1980), $20 million is added to annual operating costs. With capacity of 2 million b/d, a further $15 million increment to annual operating costs occurs in 1982.

Assumes effective 48%

(9) State and Federal income tax liability is assessed at rates of 9.4% and 48%, respectively, on taxable earnings. State income taxes are deductible before computing Federal income tax liability.

(10) In computing the ICC valuation base, original cost is $9.0 billion (including capitalized interest) for a design capacity of 1.2 million b/d, and cost of reproduction new is set at 100% of original cost less the value of land and rights-of-way, or $8.99 billion. A 5% annual inflation factor is thereafter applied to the cost of reproduction new. To the resultant weighted average value of cost of reproduction new and original cost, a condition percent factor is applied each year to obtain an estimate of the cost of TAPS in its present condition. A factor of 1.06 is then applied to this figure to reflect going concern value, before adding $60 million (representing the present value of land, present value of rights-of-way, and working capital) to obtain the final valuation rate base. A similar treatment is employed for any TAPS expansions.

? 2.0 bill

(11) In calculating tariff rates, ICC ratemaking earnings may not exceed a maximum of 10% of the above-determined, year-end valuation base. As noted below, the use of a 10% maximum rate of return on the valuation rate base is postulated on the belief that the ICC will, at a minimum, recognize the actual cost of capital of the TAPS owners in determining what is a reasonable rate level.

(12) Investment tax credits associated with qualified TAPS expenditures under the progress payment method accrue to the owners and not to the shippers in the form of a reduced cost of service (i.e., a lower tariff).

(13) Company ownership interests in TAPS are currently as follows:

(See table on following page)

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Company	% of TAPS Owned
Sohio Pipe Line Company*	33.34%
ARCO Pipe Line Company	21.00
Exxon Pipeline Company	20.00
BP Pipelines, Inc.*	15.84
Mobil Alaska Pipeline Company	5.00
Union Alaska Pipeline Company	1.66
Phillips Petroleum Company	1.66
Amerada Hess Corporation	1.50
	100.00%

!!

50 Sohio wants TAPS loss, hi wh profits

** As a consequence of the substantial escalation in the estimated cost of TAPS since the pipeline was first planned in 1969, BP and Sohio entered into an agreement as of July 1974 providing that BP Pipelines would acquire a 15.84% undivided interest in TAPS from Sohio Pipe Line in order to facilitate the financing of TAPS. The agreement contemplates that BP Pipelines will lease its undivided interest in the pipeline to Sohio for at least 18 years, and that during the term of the lease Sohio will operate its and BP Pipelines' interests in TAPS. The rental payments to be made by Sohio under the lease would be based upon the profits and tax benefits realized by it from the operation of BP Pipelines' TAPS interest. As to tariffs charged by Sohio and BP, they may not be significantly higher than the highest tariff charged by a third party in respect of TAPS (except that neither company shall be obligated to post a tariff that does not reflect compensation for normal debt service and normal operating costs).*

DB predicts companies will smooth

Utilizing the foregoing assumptions, Tables 10 and 11 present TAPS tariffs and earnings for selected years at pipeline capacity levels of 1.6 (Case I) and 2 million b/d (Case II). In constructing the Tables, we have developed a series of annual unsmoothed tariffs corresponding to the postulated composite profile of the TAPS owner companies. Under the undivided interest form of pipeline ownership, however, each of the owner companies will separately post tariffs and receive tenders of crude oil for shipment through its share of overall pipeline capacity which will be operated as a common carrier. Moreover, the tariff figure for each TAPS owner will be different for several reasons: (1) cost of the debt capital; (2) financing strategy -- debt/equity ratio; and (3) for several companies, the ownership in the pipeline is not the same as the ownership in field reserves, thereby potentially spawning a diversity of viewpoints on the best way to maximize integrated earnings.

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As Tables 10 and 11 on the following pages show, the economics of North Slope oil vary considerably, given fluctuations in TAPS throughput. For Case I (field development limited to the Prudhoe Oil Pool), annual tariffs in the period 1978-1990 range between \$3.54 and \$5.14 per barrel, with an average value of \$3.99 per barrel. Reflecting the economies of scale associated with higher levels of TAPS capacity utilization, the comparable annual tariffs for Case II (field development encompassing all three state-defined pools – Prudhoe, Kuparuk, and Lisburne – within the Prudhoe Bay field) range from \$3.14 to \$4.28 per barrel, averaging \$3.55 per barrel over the entire period. Briefly explained, the tariff reduction that occurs at progressively higher levels of pipeline throughput above the initial design capacity of 1.2 million b/d is attributable to the relatively low cost at which increments to initial capacity can be obtained. It is also evident from the Tables that the level of GAAP earnings is essentially unchanged as between Cases I and II, meaning that declining unit depreciation charges associated with high levels of pipeline throughput are reflected in a higher wellhead price (and earnings) and not at the pipeline level, where the economies of scale arise. The explanation for this somewhat paradoxical conclusion, of course, rests with the manner in which pipeline earnings are computed (i.e., as a fixed percentage of an ICC-determined valuation base).

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Table 10

TAPS Tariff and Earnings Model (a)

Case I: Pipeline Capacity 1.6 Million B/D

	1978		1979		1980		1985		1990	
Operating Revenues (in mils.)	$1854.4		$1873.9		$1855.8		$2184.7		$2383.0	
Oil Shipments (mils. of bbls.)	438.0		438.0		518.0		584.0		464.0	
TAPS Tariff	$4.23		$4.28		$3.58		$3.74		$5.14	
	Amount	Per Bbl.	Amount	Per Bbl.	Amount	Per Bbl.	Amount	Per Bbl.	Amount	Per Bbl.
Operating Revenues	$1854.4	$4.23	$1873.9	$4.28	$1855.8	$3.58	$2184.7	$3.74	$2383.0	$5.14
Interest Expense	700.4	1.60	671.8	1.53	699.9	1.35	549.9	0.94	392.8	0.85
Depreciation	216.9	0.50	216.9	0.50	216.9	0.42	238.8	0.41	238.8	0.51
Property Taxes	146.0	0.33	149.3	0.34	146.5	0.28	120.8	0.21	94.5	0.20
Amort. of Cap. Interest	51.0	0.12	51.0	0.12	51.0	0.10	56.5	0.10	56.5	0.12
Res. for Rem. of Surface Facil.	45.1	0.10	45.1	0.10	53.4	0.10	60.2	0.10	47.8	0.10
Operating Costs	175.0	0.40	184.0	0.42	213.0	0.41	272.0	0.47	323.0	0.70
Total Operating Expenses	1334.4	3.05	1318.1	3.01	1380.7	2.67	1298.1	2.22	1153.4	2.49
Pretax Earnings	520.0	1.19	555.8	1.27	475.1	0.92	886.6	1.52	1229.6	2.65
Income Taxes (b)	275.0	0.63	294.0	0.67	251.2	0.49	468.9	0.80	650.3	1.40
-State	48.9	0.11	52.2	0.12	44.7	0.09	83.3	0.14	115.6	0.25
-Federal	226.1	0.52	241.7	0.55	206.6	0.40	385.5	0.66	534.7	1.15
ICC Earnings (c)	$ 945.4	$2.16	$ 933.7	$2.13	$ 923.7	$1.78	$ 967.6	$1.66	$ 972.1	$2.09
GAAP Earnings (d)	$ 245.0	$0.56	$ 261.9	$0.60	$ 223.8	$0.43	$ 417.7	$0.72	$ 579.3	$1.25

(a) Totals may not add due to rounding.
(b) Operating revenues less operating expenses (incl. interest expense), times combined statutory tax rate.
(c) Operating revenues less operating expenses (excl. interest expense) and less income taxes.
(d) ICC earnings less interest expense. Note that GAAP earnings as shown do not include ITC benefits accruing to the companies.

Table II

TAPS Tariff and Earnings Model (a)

Case II: Pipeline Capacity 2.0 Million B/D

	1978	1979	1980	1985	1990
Operating Revenues (in mils.)	$1854.4	$1873.9	$1855.8	$2272.5	$2498.9
Oil Shipments (mils. of bbls.)	438.0	438.0	518.0	723.0	591.0
TAPS Tariff	$4.23	$4.28	$3.58	$3.14	$4.23

	Amount	Per Bbl.	Amount	Per Bbl.	Amount	Per Bbl.	Amount	Per Bbl.	Amount	Per Bbl.
Operating Revenues	$1854.4	$4.23	$1873.9	$4.28	$1855.8	$3.58	$2272.5	$3.14	$2498.9	$4.23
Interest Expense	700.4	1.60	671.8	1.53	699.9	1.35	579.7	0.80	414.1	0.70
Depreciation	216.9	0.50	216.9	0.50	216.9	0.42	251.7	0.35	251.7	0.43
Property Taxes	146.0	0.33	149.3	0.34	146.5	0.28	127.9	0.18	100.1	0.17
Amort. of Cap. Interest	51.0	0.12	51.0	0.12	51.0	0.10	58.0	0.08	58.0	0.10
Res. for Rem. of Surface Facil.	45.1	0.10	45.1	0.10	53.4	0.10	74.5	0.10	60.9	0.10
Operating Costs	175.0	0.40	184.0	0.42	213.0	0.41	289.0	0.40	347.0	0.59
Total Operating Expenses	1334.4	3.05	1318.1	3.01	1380.7	2.67	1380.8	1.91	1231.8	2.08
Pretax Earnings	520.0	1.19	555.8	1.27	475.1	0.92	891.7	1.23	1267.1	2.14
Income Taxes (b)	275.0	0.63	294.0	0.67	251.2	0.49	471.6	0.65	670.1	1.13
-State	48.9	0.11	52.2	0.12	44.7	0.09	83.8	0.12	119.1	0.20
-Federal	226.1	0.52	241.7	0.55	206.6	0.40	387.8	0.54	551.0	0.93
ICC Earnings (c)	$ 945.4	$2.16	$ 933.7	$2.13	$ 923.7	$1.78	$ 999.8	$1.38	$1011.0	$1.71
GAAP Earnings (d)	$ 245.0	$0.56	$ 261.9	$0.60	$ 223.8	$0.43	$ 420.1	$0.58	$ 596.9	$1.01

(a) Totals may not add due to rounding.
(b) Operating revenues less operating expenses (incl. interest expense), times combined statutory tax rate.
(c) Operating revenues less operating expenses (excl. interest expense) and less income taxes.
(d) ICC earnings less interest expense. Note that GAAP earnings as shown do not include ITC benefits accruing to the companies.

As noted at the outset of this discussion of pipeline issues and economics, the tariff-setting process for TAPS is presently engulfed in considerable uncertainty – the resolution of which must perforce await future developments involving the ICC and the State of Alaska. Given the importance of the level of the TAPS tariff in the overall economics of North Slope oil, some perspective on the nature and likely basis for resolution of the tariff uncertainty is warranted.

Independent of, but inextricably tied to, the outcome of the ICC's upcoming Ex Parte No. 308 review of the continued applicability of its 8% return standard for crude oil pipelines is the little understood (certainly by the investment community) matter of how TAPS tariffs and reported pipeline earnings will be affected by the Commission's current procedure, as outlined in the WBPL rate proceeding, for calculating ratemaking earnings. The fundamental question involved here is whether total pipeline investment or the equity capital portion alone is the appropriate basis for determining maximum allowable earnings for ratemaking purposes.

By relying on the precedent of the *Elkins Act* Consent Decree ruling of 1941, and the findings of a later contest of that ruling (the Arapahoe Pipeline case), the TAPS owners subject to the original Consent Decree have historically proceeded on the assumption that they could earn and pay as dividends to their parents 7% of the ICC's valuation of their common carrier properties, *after* recognizing interest charges on pipeline debt as a separate component in the tariff buildup. Therefore, the companies were somewhat surprised (to be read, shocked) to learn that the ICC was employing a ratemaking methodology other than that of the *Elkins Act* to measure the reasonableness of the rates of the Williams Brothers Pipe Line.* Although WBPL is primarily a petroleum products carrier, when the ICC treated the company's interest expense for ratemaking purposes it appeared to be implicitly saying that a regulated oil pipeline could earn 8% or 10% (if a products carrier) on valuation over and above interest expense on an equity capital basis – an approach not unlike the FPC's for natural gas pipelines. Given that interest expense is initially deducted from operating revenues in computing GAAP, earnings and then added back to the latter amount to arrive at ratemaking earnings (see footnotes to Table 10), *the net effect is a successive lowering of the tariff, which, in turn, forces down GAAP earnings (since interest expense is treated as a constant in the ratemaking earnings figure).* In essence, the highly leveraged nature of TAPS,** together with a debt cost that exceeds the ICC's 8% return ceiling, results in an excessive rate of return (at least by ICC standards) and a consequent necessity to lower the tariff. This pattern can be easily seen in Table 12.

**To the extent a future rate case involving TAPS reaches the ICC, a salient issue is likely to be whether or not the 1941 Elkins Act Consent Decree and the related Arapahoe Pipeline proceeding are binding on the ICC. According to Commission officials contacted by the writers, the Consent Decree arose out of a Justice Department investigation, and as such, was not a pipeline rate case which set a precedent for the ICC to follow. On the other hand, a view likely to be proffered by the companies would go as follows: since the Consent Decree dealt with pipeline earnings, and a pipeline company's earnings are calculated using tariffs, it follows that the Elkins Act Consent Decree should be binding on the ICC.*

***To avoid the impact of the 7% Consent Decree limitation, pipelines have modified their capital structures by reducing the amount of equity and thereby leveraging the 7% figure to a much higher percent of equity investment.*

Table 12

Alternative Tariff and Earnings Computation -- 1978 (a)
(In millions except per barrel)

	Elkins Act Basis (b)	ICC Basis (c)	
	7% Return	8% Return	10% Return
TAPS Tariff	$6.25/bbl.	$3.32/bbl.	$4.23/bbl.
Operating revenues	$2,739.2	$1,453.1	$1,854.4
Interest expense	700.4	700.4	770.4
Depreciation	216.9	216.9	216.9
Property taxes	146.0	146.0	146.0
Amortization of cap. interest	51.0	51.0	51.0
Res. for rem. of surface facil.	45.1	45.1	45.1
Operating costs	175.0	175.0	175.0
Total operating expenses	$1,334.4	$1,334.4	$1,334.4
Pretax earnings	1,404.8	118.7	520.0
Income taxes	743.0	62.8	275.0
– State	132.1	11.2	48.9
– Federal	610.9	51.6	226.1
ICC earnings	$ 661.8	$ 756.3	$ 945.4
GAAP earnings	$ 661.8	$ 55.9	$ 245.0

(a) Totals may not add due to rounding.

(b) Under the Consent Decree, affected shipper-owners are allowed to post tariffs based on a return on their total pipeline investment.

(c) Assumes tariffs reflect a residual return based on the equity component of investment only. A revised calculation using a 10% return ceiling is used to more properly reflect an estimated cost of capital applicable to the TAPS owners in the aggregate.

Strict adherence to an 8% return ceiling using the ICC ratemaking methodology employed in Williams Brothers results in a tariff of $3.32 per barrel and reported (GAAP) earnings of $55.9 million for 1978, far below the situation prevailing under *Elkins Act* treatment. On the assumption that the ICC would, at a minimum, establish a fair rate of return on value reflective of the actual cost of capital associated with TAPS,* the writers also include a revised set of calculations based on a 10% return on valuation. Accordingly, a $245 million net profit in 1978 would translate into a 27% rate of return (versus 74% under the *Elkins Act* Consent Decree) on $900 million of pipeline equity.

**On the assumption that 90% of the cost of TAPS is borrowed at an effective rate of 9% and that the remaining 10% equity contribution has an after-tax cost of 15%-20%, the weighted average cost of capital for TAPS would be as follows:*

90% debt @ 9%	=	*8.1%*
10% equity @ 15%-20%	=	*1.5%- 2.0%*
weighted average	=	*9.6%-10.1%*

industry argument !!

If a rate proceeding involving TAPS occurs, the owner companies would undoubtedly argue that a parent company capital structure would be the proper one to impute in measuring cost of capital. Unlike a gas pipeline, where the gas company typically assumes only a portion of the risk, in the case of TAPS, lending institutions are looking past the pipeline subsidiaries to the parent companies for ultimate payment should TAPS, for one reason or another, be economically unviable. Since an oil pipeline involves a set of risks and obligations different from those inherent in the utility concept underlying a gas pipeline, so the argument goes, an oil pipeline should not be viewed on a stand-alone basis.

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Because the incidence of taxation by the State of Alaska is lower on the pipeline than at the wellhead, other things being equal, a lower pipeline tariff would be reflected in a modest reduction in integrated profits for the Prudhoe Bay producers. However, under the ICC ratemaking procedure described above, the impact on integrated profits stemming from a shift in the incidence of taxation is greatly exacerbated by the residual manner in which GAAP earnings are calculated (i.e., as the difference between maximum permitted ratemaking earnings and interest expense). To the extent that a fixed valuation return ceiling is indiscriminately applied to all crude oil pipelines, BP and Sohio in particular stand to be adversely affected given their relatively high cost of debt capital. For Sohio (and indirectly BP through its equity ownership in the company), however, its current prospect of being a substantial net purchaser of pipeline transportation services provides a partial offset to the potential profit impact arising from a low pipeline tariff and a concomitant squeeze on GAAP earnings. From the standpoint of the State of Alaska -- whose concern regarding the potential revenue loss associated with a high pipeline tariff has bordered on the extreme -- the implications of the ICC's return on equity approach to ratemaking, if applied to TAPS, could conceivably result in a more stable tax environment for the petroleum industry in Alaska than might otherwise prevail.

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As matters now stand, the TAPS owners are apparently moving forward to post initial tariffs on an *Elkins Act* basis, in the belief that past practice affords good justification for continuing to use this tariff-setting approach. That action, in turn, will undoubtedly precipitate the filing of a contested rate application by Alaska in an attempt to protect its revenue interests -- thus joining the battle lines for what is shaping up as the most significant pipeline tariff dispute since the Interstate Commerce Commission gained jurisdiction over the pipeline field.

In past years, one reason why so few oil pipeline rate cases have reached the full Commission is because most areas of potential dispute were resolved in the early stages of a pipeline's life between the line owners and the ICC staff through a process of exceptions and appeals.* Unfortunately, such an outcome does not appear to be in the offing for TAPS. As one example of the complexities militating against a simple resolution of potential areas of dispute, what amount will be includable in the TAPS tariff for "negative salvage value" -- that is, those costs associated with the eventual removal of all above-ground facilities at some undetermined time? Moreover, owing to the sheer size of TAPS (once constructed, it will represent an investment cost exceeding that of the 100 or so other pipelines under ICC jurisdiction) plus the pioneering efforts entailed in constructing the first "hot oil" pipeline ever built in an Arctic environment, not to mention the unprecedented Government involvement in all phases of the project, it becomes a difficult, if not impossible, task to apply the test of 20-20 hindsight, utilizing the prudent man rule, fairly to this project. In this light, the audit section of the ICC's Bureau of Accounts has already begun to investigate Alyeska with the dual objective of validating its actual cost figures and evaluating those management activities and decisions (such as labor usage and pricing and the remedial welding program) that could have contributed to cost overruns on the pipeline.** To the extent

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**The main reason for the limited number of rate cases occurring over the years, of course, is traceable to the fact that pipeline ownership has typically been in the hands of the shippers.*

***Not to be outdone, Senator Jackson has requested the Government Accounting Office (GAO) to conduct an investigation of TAPS along lines similar to that of the ICC. Presumably, the GAO study, which is being undertaken in three separate stages, would be used in any future Congressional hearings on the pipeline question.*

questionable costs are identified and eliminated, the original cost figure inserted into the valuation base computation would be lower than the $8.99 billion incorporated in our tariff model. Referring back to Table 10, if $500 million was slashed from the number for original cost, in 1978, the per-barrel tariff would fall from $4.23 to $3.98 and GAAP earnings would decline from $245 million to $193 million.

The Alaska Pipeline Commission (APC),* acting on behalf of the State of Alaska, has hired a Washington-based consultant to conduct an investigation into the reasons for (and appropriate documentation of) alleged cost overruns in the construction of TAPS. This study could put some political pressure on the parallel ICC investigation, and also aid the APC in setting tariffs for that portion of North Slope oil sold within the state.

Once the question of the pipeline's original cost has been resolved by the audit section through the exceptions and appeals process, the ICC valuation staff will then be given the vexsome task of determining a cost of reproduction new and, more broadly, a final valuation base for TAPS.** Based on the methodology outlined on page 39, an initial valuation as of December 31, 1977 will probably not be forthcoming until the end of 1978, and at that, may encompass only those companies having other common carrier properties (ARCO Pipe Line, Exxon Pipeline, Mobil Pipe Line, and Sohio Pipe Line). Once TAPS is beyond the 1977 startup stage, the valuation staff expects to have a more realistic picture of TAPS' operations on which to base the 1979 valuation report (covering year-end 1978). From our discussions with ICC valuation officials, the 1979 report is likely to serve as the fair value rate base on which a final evaluation of the reasonableness of the TAPS tariffs may ultimately be made.

tariff won't be "set" till 1979

The Alaska Pipeline Commission was formed in 1972 as one element of a broad legislative package dealing with the petroleum industry. In addition to being the state regulatory body where intrastate movements of oil and gas are concerned, a current bill in the House (HB 145) would allow the APC to determine pipeline taxable income according to its regulations (now being developed) if no ICC valuation has been made of an interstate oil pipeline facility or if the oil pipeline facility is engaged wholly or partially in intrastate commerce. Needless to say, the TAPS owners are viewing this authority (to the extent it is not pre-empted by the Federal Government) and the development of the APC's pipeline regulatory apparatus with a great deal of concern.

***In the lower-48 states, the cost of reproduction new has typically amounted to 80%-90% of original cost. To further illustrate the one-of-a-kind nature of TAPS, one of the companies indicated to the writers that it is planning on the basis of cost of reproduction new being 110% of original cost, mainly reflecting the long construction leadtime and intervening rates of inflation more than offsetting any downward bias introduced by the application of the prudent man rule to the construction of the line. If cost of reproduction new at 110% of original cost is substituted for the 100% figure used in our 1978 base case, the per-barrel tariff would rise to $4.49 and GAAP earnings would climb to $298 million.*

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

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

Even if the State of Alaska is satisfied with the outcome of the ICC investigation of Alyeska (most importantly, the amount of costs included in the rate base), the substantial questions raised by the protestants in the WBPL rate case would appear to justify a rate challenge in any event, especially if the tariffs are based on the *Elkins Act* Consent Decree.* As such, final resolution of the uncertainty surrounding the tariff appears to rest on the convergence of a TAPS rate case and/or the conclusion of the Ex Parte No. 308 proceeding – both of which promise to be drawn-out affairs.

Sometime in the first half of 1977, after interested parties have had an opportunity to make and respond to written submissions, an Administrative Law Judge is expected to commence hearings. Considering the broad scope of this proceeding, and a companion investigation (Ex Parte No. 308 (Sub.-No. 1), *Investigation of Common Carrier Pipelines*), it may be two years or so before the full Commission acts on the matter. While a plethora of revenue and expense items affecting pipeline tariffs and earnings will be addressed in the context of Ex Parte No. 308, such as the treatment of interest expense, depreciation, and capitalized interest for ratemaking purposes, the critical issues will boil down to what is a proper rate base and what is an appropriate return level on that base in view of the risk and economic/financial climate facing the pipeline industry today. Having reviewed the record of the WBPL proceeding in some detail, our best guess as to the final outcome on these key issues is that the ICC will: (1) retain the valuation rate base concept essentially intact; (2) reaffirm the cost-of-service ratemaking treatment outlined in Williams Brothers (particularly to the extent that the ICC becomes more politicized); and, (3) permit a higher return ceiling than the current 8% and 10% levels to properly reflect today's cost of capital.

basic questions

It should be fairly obvious from the preceding discussion that any attempt to accurately forecast pipeline tariffs and earnings is fraught with major imponderables. While an endless number of permutations and combinations can be constructed as a means of defining sensitivities, in the end, a useful earnings estimate must rest on a limited number of possibilities. Thus, in developing our 1977-1980 North Slope earnings estimates, we used only two alternatives for deriving TAPS tariffs and pipeline earnings: (1) the traditional *Elkins Act* Consent Decree method, the basis on which the companies (with the possible exception of Amerada Hess) apparently intend to file, at least initially; and (2) the return on equity approach outlined by the ICC in the WBPL proceeding. These two cases can also be viewed as bracketing the eventual outcome.

find this!!

Production Economics

In an attempt to systematically assess North Slope production economics, the authors have developed a generalized computer model that, based on certain data inputs and assumptions, generates a series of integrated unit profitability figures (the pipeline numbers are fed in by a separate computer sub-routine) linked to a number of potential end markets for Alaskan oil. The model provides the necessary profit data to construct earnings profiles for the North Slope producers followed by Wainwright Securities, and also yields other lesser benefits, such as an ability to analyze the discounted cash flow economics and distribution of oil revenues

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**More recently, in the context of a petition filed by the state with the ICC requesting an immediate prehearing conference on the issues of pipeline rates and the notification period required for filing initial tariffs (now 30 days), it became apparent that Alaska has also engaged the counsel who argued the protestants case in the WBPL proceeding.*

for the Prudhoe Bay field. In addition, the model facilitates rapid updating as the inevitable changes occur and/or better data becomes available.

Beyond this general introduction to our methodology for analyzing North Slope production economics, the following points more fully outline the manner in which such economics are determined and also provide a useful guide to the Tables presented in the body of the report and Appendix C for the various markets of destination under review.

Methodology for Derivation of Unit Producing Profits

(1) Markets of Destination. Although a number of other possibilities exist as regards ultimate movements of North Slope crude, our analysis is limited to Puget Sound, San Francisco, Los Angeles/Long Beach, Houston (a representative Gulf Coast port), Chicago (which also encompasses points along the Northern Tier), and Yokohama/Tokyo.

(2) Production. Based on currently proven reserves of 9.7 billion barrels of crude and condensate in the main (Sadlerochit) reservoir, a production profile has been plotted through the year 2005 which reflects guidance furnished by field operators as well as the State of Alaska. At an assumed MER level of 1.6 million b/d for the Prudhoe Bay Unit, output commences at a rate of 300,000 b/d in July 1977, building up to the 1.2 million b/d level towards year-end. Peak production of 1.6 million b/d is attained in the second half of 1980 and holds constant at that rate through 1986, after which a decline curve sets in. A separate analysis provides for development of 2 billion barrels of speculative reserves in the Kuparuk and Lisburne formations. Production from these more marginal reserves begins in 1982, reaching a peak rate of 380,000 b/d in 1985.

(3) Crude Oil Price. As discussed in the pricing section, two different cases are postulated. Case I assumes a world price for Prudhoe Bay crude tied to the landed value of 34° Saudi Arabian Light (less a 25¢/bbl. quality adjustment) in each market of destination (see Table 7 on page 25). Beyond mid-1977, the delivered cost of Saudi Light is escalated at an annual rate of 4.5%. (In light of a developing global shortage of petroleum, this assumption could be conservative, especially after 1985.) Case II assumes the price of Prudhoe Bay crude is set equal to the current upper tier price for a comparable grade of California crude oil (27° Signal Hill). In August 1977, after a lengthy hiatus, the currently frozen upper tier price of $9.91/bbl. for this crude is permitted to rise within the constraints set by the EPCA composite formula through May 1979. Thereafter, the price moves up at a 5% annual rate, essentially in line with that assumed for the delivered cost of Saudi Light.

(4) Marine Transportation. Except for the Houston market where two tanker movements are necessitated, the marine transportation figure reflects the cost of moving the oil from Valdez to one of the principal West Coast ports or Japan. Where an additional movement through the

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Panama Canal to Houston occurs, the incremental cost from Long Beach to Houston is added to the Valdez-Long Beach base figure. A 3% annual escalation has been applied to the initial marine transportation values for each route to cover increases in variable costs.

(5) TAPS Liability Fund. To comply with Interior Department oil spill liability requirements, a cost of 5¢/bbl. will be assessed for each barrel of oil loaded onto tankers at Valdez until a $100 million fund has been built up.

(6) Pipeline Transportation. This category corresponds to the cost incurred in moving North Slope oil via lower-48 pipeline systems. For Houston, this entails Sohio's LATEX system from Long Beach-Midland and thence via connecting pipeline to Houston. The Chicago market is assumed to be served by the Trans Mountain pipeline running from the Puget Sound area to Edmonton, Alberta. From Edmonton, the oil is shipped through the Interprovincial and Lakehead systems to Chicago. The base values used for lower-48 pipeline movements escalate at a 1½% annual rate in subsequent years.

(7) Valdez Netback. Landed crude price minus marine transportation, TAPS Liability Fund, and lower-48 pipeline transportation. like Mortada

(8) Wellhead Price. Valdez netback less TAPS tariff.

(9) Royalty. Royalty is calculated at 12½% of the wellhead value, payable either in cash (our assumption) or in kind. It appears that at least a portion of Alaska's royalty oil entitlement will be taken in kind to supply Energy Company of Alaska's new refinery near Fairbanks. royalty oil (not production)

(10) Production Taxes. As discussed in the *Alaskan Taxation* section, production taxes for the Prudhoe Bay field are based on the Economic Limit Factor (ELF) concept contained in the Hammond Administration's recently submitted oil industry tax proposals. Thus, on the assumption of a base tax rate of 10%, the production taxes actually paid in a given year are determined as the greater of alternative cents-per-barrel and percent-of-value calculations.* The "floor" price for the cents-per-barrel minimum tax starts at $7.50 per barrel in 1977 and is escalated thereafter at an annual rate of 5% to reflect inflation. The product of the "floor" price times the base tax rate of 10% is then multiplied by ELF to arrive at the cents-per-barrel minimum tax. Based on inputs of annual production data and the number of wells estimated to be producing each year, an ELF series is computed over the life of the field which, when multiplied by the base tax rate of 10%, produces an effective percent-of-value tax rate to be applied each year. The percent-of-value tax is based on an economic limit for the field of 400 b/d per producing well. Assume: Floor $/barrel

**Under a system of early development incentive credits (EDIC), companies will receive, beginning in 1978, a credit against production tax liabilities for properties paying the ad valorem tax on reserves. The EDIC applicable against any future production taxes cannot exceed 50% of the severance tax on any one month's production. At a 50% rate, the state estimates that it will take roughly five years for the Prudhoe Bay field owners to recoup their $490 million of 1976-1977 reserves tax payments for the Sadlerochit formation.*

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(11) Property Taxes. Unlike TAPS, combined State of Alaska and municipal property taxes of 2% of assessed value are based on the economic value of the field facilities using a 30-year depreciable life.* A 5% per annum inflation rate has been built into the determination of the economic value of the production facilities.

not Hammond proposal

(12) Lifting Costs. Out-of-pocket operating costs for the main Prudhoe Bay field are estimated at $150 million (34¢ per barrel) for 1978. Thereafter, the base figure escalates by 5% per year. In 1981, $25 million is added to annual field operating costs reflecting startup of a field-wide water injection program. Once field output begins to decline, a provision is made for a tapering off of variable operating costs.

assumes 1981 water injection

(13) Interest Charges. A flexible loan financing routine is incorporated into the computer model for the field, which permits the user to determine the percentage of total investment to be financed by debt as well as a schedule of borrowings and repayments. Interest expense is computed at a specified rate based on the average loan balance outstanding in a given year. Interest incurred prior to the start of production is capitalized with a provision for amortization over a 15-year period once production begins. Financing of capital expenditures (exclusive of Kuparuk and Lisburne development) incurred in the post-1977 period is assumed to be accomplished using cash flow. The following assumptions underlie the loan financing configuration used in this report:

(a) Interest rate -- 9%.

(b) Borrowings -- 40% of capital expenditures, with initial drawdown occurring in 1974.

(c) Repayments -- commence in the first full year of production (1978) and are spread equally over eight years.

(14) Depreciation, Depletion, and Amortization (DD&A). Starting with initial values for reserves and total capital investment in the oil rim area, the program computes a per barrel DD&A charge to be applied to production in the next period. Any reserve additions (depletion), or additional capital investments are added (subtracted) to the balance being carried for those categories and, accordingly, would be factored into the determination of a new per barrel charge in the succeeding period. Annual investment costs for the Prudhoe Bay field were taken

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**To the extent that a number of municipalities in Alaska may also levy and collect property taxes, such taxes may be claimed as a credit by the taxpayer against the 20 mill state tax on the same properties. A new complexity has been added lately by the North Slope Borough's imposition of a 10.3 mill assessment (which exceeds its permitted maximum of 7.38 mills), the net effect of which would be to effectively increase the total levy on North Slope exploration and production facilities to 23 mills. The companies are currently engaged in litigation seeking to determine the Burrough's authority to enact the new levy and the extent to which it may be credited against the state property tax.*

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from a report submitted to the FEA by a consultant (Mortada) under a contract to determine an equitable pricing level for North Slope oil. In developing a capital cost figure for the oil rim area, and in the absence of an operating plan for the Unit on which to rely, the writers have arbitrarily allocated 75% of gas injection development costs (mainly the field fuel gas unit and the central gas compression plant) incurred through 1977 to oil production. Provision has also been made for book amortization of North Slope leasehold acquisition costs on the unit-of-production method over the life of the field. The amortization rate amounts to about 4¢/bbl.

(15) Income Taxes. State and Federal income tax liability is assessed at rates of 9.4% and 48%, respectively, on taxable earnings. State income taxes are deductible before computing Federal income tax liability.

(16) Company Interests. In the absence of a final owners' agreement for the Prudhoe Bay Unit, production interests in the oil rim area have been estimated as follows:

Company	% Interest in Oil Rim	Final
Sohio/BP	53.2%	53.155
Arco	20.5	20.273
Exxon	20.5	20.273
Mobil	2.1	6.299
Phillips	2.1	
Socal	0.8	
PLAGM	0.8	
	100.0%	

To illustrate the workings of Wainwright's Prudhoe Bay field profitability model, Tables 13 and 14 breakdown results for the Long Beach market for selected years.

(See Tables 13 and 14 on following pages)

Table 13

Prudhoe Bay Field -- Main (Sadlerochit) Reservoir
Derivation of Unit Producing Profits
Market of Destination -- L.A./Long Beach (a)

Case I: World Price

	1978		1979		1980		1985		1990	
Production Rate (millions of b/d)		1.20		1.20		1.42		1.60		1.27
Landed Crude Price		$13.93		$14.55		$15.21		$18.95		$23.62
Marine Transportation		0.71		0.73		0.75		0.87		1.01
TAPS Liability Fund		0.05		0.05		0.05		0.00		0.00
Pipeline Transportation		0.00		0.00		0.00		0.00		0.00
Valdez Netback		13.17		13.77		14.40		18.08		22.60
TAPS Tariff		4.23		4.28		3.58		3.74		5.14
Wellhead Price		8.94		9.49		10.82		14.34		17.46
Royalty @ 12.5%	1.12		1.19		1.35		1.79		2.18	
Production Taxes	0.75		0.78		0.90		1.16		1.30	
Property Taxes	0.14		0.16		0.16		0.30		0.38	
Lifting Costs	0.34		0.36		0.32		0.41		0.62	
Interest Charges	0.22		0.20		0.14		0.03		0.03	
Depr., Depl., and Amort.	0.35		0.40		0.46		1.12		1.19	
Total Costs		2.92		3.09		3.34		4.82		5.71
Pretax Profit		6.02		6.40		7.49		9.52		11.76
Income Taxes										
- State @ 9.4%	0.57		0.60		0.70		0.90		1.11	
- Federal @ 48%	2.62		2.78		3.26		4.14		5.11	
Total Income Taxes		3.18		3.39		3.96		5.04		6.22
Net Profit		$ 2.84		$ 3.02		$ 3.53		$ 4.49		$ 5.54
TAPS Profit		0.56		0.60		0.43		0.72		1.25
Integrated Profit		$ 3.40		$ 3.62		$ 3.96		$ 5.21		$ 6.79

(a) Totals may not add due to rounding:

Table 14

Prudhoe Bay Field -- Main (Sadlerochit) Reservoir
Derivation of Unit Producing Profits
Market of Destination -- L.A./Long Beach (a)

Case II: Controlled Price

	1978		1979		1980		1985		1990	
Production Rate (millions of b/d)		1.20		1.20		1.42		1.60		1.27
Landed Crude Price		$12.19		$13.17		$13.67		$17.45		$22.27
Marine Transportation		0.71		0.73		0.75		0.87		1.01
TAPS Liability Fund		0.05		0.05		0.05		0.00		0.00
Pipeline Transportation		0.00		0.00		0.00		0.00		0.00
Valdez Netback		11.43		12.39		12.87		16.58		21.26
TAPS Tariff		4.23		4.28		3.58		3.74		5.14
Wellhead Price		7.20		8.11		9.29		12.84		16.12
Royalty @ 12.5%	0.90		1.01		1.16		1.60		2.01	
Production Taxes	0.75		0.78		0.82		1.04		1.21	
Property Taxes	0.14		0.16		0.16		0.30		0.38	
Lifting Costs	0.34		0.36		0.32		0.41		0.62	
Interest Charges	0.22		0.20		0.14		0.03		0.03	
Depr., Depl., and Amort.	0.35		0.40		0.46		1.12		1.19	
Total Costs		2.70		2.91		3.07		4.51		5.44
Pretax Profit		4.50		5.20		6.22		8.33		10.68
Income Taxes										
- State @ 9.4%	0.42		0.49		0.58		0.78		1.00	
- Federal @ 48%	1.96		2.26		2.70		3.62		4.64	
Total Income Taxes		2.38		2.75		3.29		4.41		5.65
Net Profit		$ 2.12		$ 2.45		$ 2.93		$ 3.92		$ 5.03
TAPS Profit		0.56		0.60		0.43		0.72		1.25
Integrated Profit		$ 2.68		$ 3.05		$ 3.36		$ 4.64		$ 6.28

(a) Totals may not add due to rounding.

Similar presentations for the other markets of destination dealt with in this report are included as attachments in Appendix C. For ease of comparison, however, Table 15 provides a useful summary of how unit producing profits would compare by end market in 1980 under the different price cases.

Table 15

Unit Producing Profits by Market of Destination – 1980
($ Per barrel)

Market	Crude Oil Price* Case I	Case II
Japan	$3.32	–
Puget Sound	3.59	$3.02
San Francisco	3.51	2.88
L.A./Long Beach	3.53	2.93
Houston	3.10	2.35
Chicago	3.45	2.60

Case I: World price.
Case II: Controlled upper tier price.

North Slope Crude Oil Movements

Having developed projections for Prudhoe Bay unit producing profits in each of six principal refinery markets, the analysis next outlines a possible 1977-1980 marketing model for North Slope output. In it, the writers attempt to apportion each of the major companies' crude liftings among the markets. In the concluding section of this *Industry Review*, the marketing scenario we develop is superimposed on unit producing profits by market, thereby yielding a total production earnings figure for each company. Such figures properly reflect the varying per-barrel margins for the oil in the different markets in which it will ultimately be sold.

The starting point in the construction of the model is a definition of available West Coast refining capacity for processing crude oil with Prudhoe Bay-type characteristics. Based on the results of an FEA survey of the capability of West Coast refineries to run North Slope crude (see footnote on page 15) the indicated physical capacity available to process this oil in 1978 ranges from 601,000 b/d to 969,000 b/d. Using the mid-point of the range, or 785,000 b/d, plus an additional 20,000 b/d from debottlenecking of Exxon's Benicia refinery, the aggregate capacity is then broken down between Puget Sound, San Francisco, and L.A./Long Beach.* (To isolate the situation facing the major Prudhoe Bay reserve owners, production of the PLAGM group – which by our estimate will amount to only 0.8% of the total for the Prudhoe Bay Unit – has been proportionately allocated between the San Francisco and L.A./Long Beach markets, but is otherwise excluded from the analysis.) Next, each

**Because the leadtime inherent in accomplishing a major refinery conversion project to permit the processing of North Slope crude will make meaningful amounts of new capacity potentially available only after 1980, the 805,000 b/d capacity level is assumed to remain constant during 1978-1980.*

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Amerada Hess

company's captive movements to the West Coast, either to its own refineries or to those of a non-affiliated refiner under a known contractual arrangement (i.e., Phillips' deal to move crude to its former Avon refinery, now owned by Toscopetro), are backed out of the total capacity figure for each market (adjusted for PLAGM) to derive the residual third party market.*

how??

At this juncture, the writers assume that those companies still having oil to market will share the third-party market based on each one's percentage share of the remaining oil to be marketed. While this is the general approach followed, two external constraints have been imposed in an effort to make the analysis more realistic. The constraints are as follows: (1). Sohio obtains the entire third-party crude market in Puget Sound; and (2) owing to a limitation on vessel size in the Port of San Francisco, Atlantic Richfield makes no crude sales in that refinery market area. Using this methodology, the North Slope crude running capacity of Puget Sound, L.A./Long Beach, and San Francisco is successively utilized until a total of 805,000 b/d is placed on the West Coast.

Once the available West Coast market for North Slope crude has been fully satisfied, provision must then be made for disposing of the remaining surplus volumes elsewhere. Until 1979, when the first inland pipeline delivery system (Trans Mountain's yo-yo) is assumed to become operational, any crude volumes surplus to the needs of the West Coast are shipped through the Panama Canal via tanker to Houston. In 1978, some 395,000 b/d (split between Arco, Exxon, and Sohio) will be moved in this manner. With the availability of 165,000 b/d of capacity to move oil eastward in the yo-yo system, however, movements to the Northern Tier and on into the Chicago refinery center become a feasible alternative. Since the Valdez netback on pipeline shipments along the northern route exceeds that for Houston using tankers, the principle of profit maximization (which is the general rule we apply except where certain crude oil supply and/or investment commitments dictate otherwise) would presumably lead the Prudhoe Bay producers to opt for the Northern Tier/Chicago movements over those to Houston. Once again, individual company sales are determined according to percentage interests in the remaining surplus, with the one proviso that Exxon moves at least 30,000 b/d to its Billings refinery. The balance of any additional oil to be marketed is then shipped on to Houston by tanker.

In 1980, the assumed startup of Sohio's 500,000 b/d LATEX pipeline, together with Trans Mountain's adoption of a batch reversal configuration – which increases net eastward capacity to 350,000 b/d – results in an elimination of the necessity for tanker movements to Houston. Because of Sohio's substantial investment commitment to the LATEX pipeline system, in working with that company's 1980 marketing strategy for non-P.A.D. District V destinations, movements to Houston utilizing the pipeline are assumed to take precedence over those to the Northern Tier/Chicago area, a lower Valdez netback notwithstanding. The same general line of reasoning would apply to Exxon, which has recently elected to take a

what about freeze? ||

The maximum volume and destination of captive movements as used in Table 16 are as follows: Atlantic Richfield-201,000 b/d (P.S.-96,000 b/d; L.A./L.B.-105,000 b/d; Exxon-95,000 b/d (all S.F.); Mobil-29,800 b/d (P.S.-25,200 b/d; L.A./L.B. 4,600 b/d); Phillips-29,800 b/d (all S.F.); Socal-11,300 b/d (all S.F.).

20% interest in the pre-construction phase of the LATEX system as the first step towards possible full-fledged ownership in the project.

Table 16 presents Wainwright Securities' scenario for how North Slope crude oil movements might appear for 1977-1980 – and recognizes that the marketing model outlined above represents only a rough cut at what will probably become a very dynamic and complex situation. The analysis also shows the strong marketing position of Atlantic Richfield by virtue of its having some 200,000 b/d of captive West Coast movements, and the scope of the marketing challenge facing Sohio, which currently has no West Coast refining capacity. Given the investor concern surrounding the disposition of Sohio's North Slope crude, the conclusion emerging from Table 16 is that the task is manageable, albeit at some relative penalty to the company's production earnings.

(See Table 16 on following page)

Table 16

North Slope Crude Oil Movements (a)
(Barrels per day)

Company	Market: Puget Sound	San Francisco	L.A./Long Beach	Houston: Tanker	Houston: Pipeline	Northern Tier/Chicago	Totals
1977 (post-Labor Day)							
Arco	96,000	–	75,300	15,900	–	–	187,200
Exxon	–	111,800	38,800	36,700	–	–	187,200
Mobil	19,200	–	–	–	–	–	19,200
Phillips	–	19,200	–	–	–	–	19,200
Socal	–	7,300	–	–	–	–	7,300
Sohio	12,800	69,800	249,800	153,200	–	–	485,700
Totals	128,000	208,100	363,900	205,800	–	–	905,800
1978							
Arco	96,000	–	119,500	30,500	–	–	246,000
Exxon	–	127,000	48,700	70,300	–	–	246,000
Mobil	25,200	–	–	–	–	–	25,200
Phillips	–	25,200	–	–	–	–	25,200
Socal	–	9,600	–	–	–	–	9,600
Sohio	6,800	133,900	203,500	294,200	–	–	638,400
Totals	128,000	295,700	371,700	395,000	–	–	1,190,400
1979							
Arco	96,000	–	119,500	17,800	–	12,700	246,000
Exxon	–	127,000	48,700	40,300	–	30,000	246,000
Mobil	25,200	–	–	–	–	–	25,200
Phillips	–	25,200	–	–	–	–	25,200
Socal	–	9,600	–	–	–	–	9,600
Sohio	6,800	133,900	203,500	171,900	–	122,300	638,400
Totals	128,000	295,700	371,700	230,000	–	165,000	1,190,400
1980							
Arco	96,000	–	127,700	–	–	67,000	290,700
Exxon	–	128,000	49,500	–	67,200	46,000	290,700
Mobil	25,200	–	4,600	–	–	–	29,800
Phillips	–	29,800	–	–	–	–	29,800
Socal	–	11,300	–	–	–	–	11,300
Sohio	6,800	125,900	188,900	–	432,800	–	754,400
Totals	128,000	295,000	370,700	–	500,000	113,000	1,406,800

(a) *Totals may not add due to rounding*

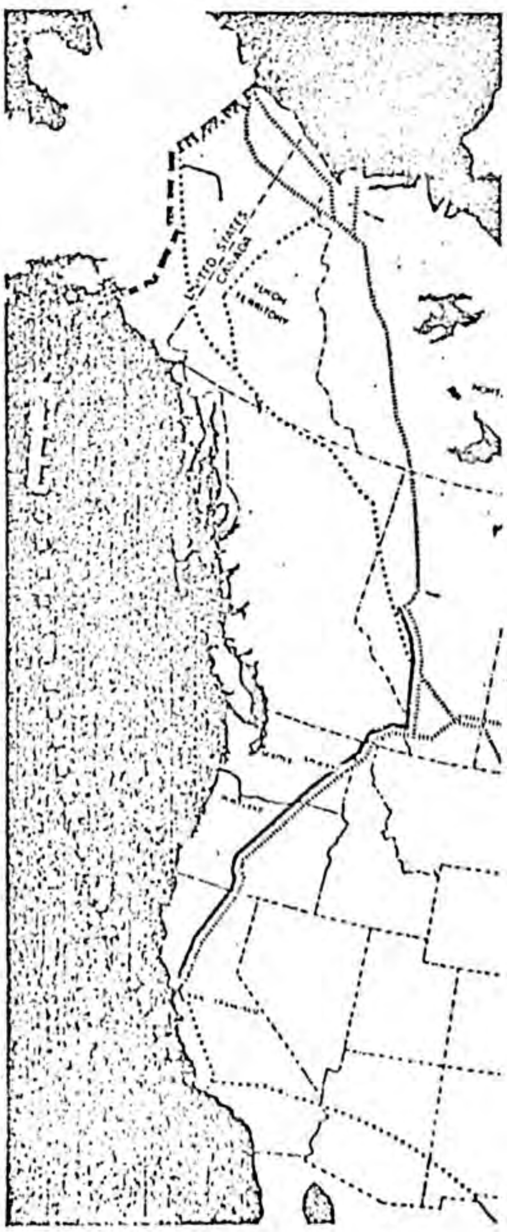
Natural Gas

gas liquids?

In addition to the crude oil and condensate which will be flowing from the main Prudhoe Bay field, a significant quantity of natural gas will also be produced during the reservoir's life. In a rare show of unanimity, all parties submitting alternative proposals for transporting Prudhoe Bay gas have agreed that proved saleable gas reserves approximate 23 trillion cubic feet, or 10% of the total proved remaining U.S. reserves of natural gas. In view of the recent shortages of lower-48 gas supplies to meet peak needs, there will probably be ample political incentive to bring these reserves onstream. Nevertheless, there are a number of uncertainties that seriously hamper a comprehensive assessment of the economics of exploiting this resource, including: (1) the time production actually begins; (2) the wellhead price realizable by the producers; and (3) the quantity of gas, net of pressure maintenance requirements, that will be available for sale.

conservation requirements

MAP II



LEGEND

- Proposed Arctic Gas Transmission System
- Proposed El Paso Transmission System
- Existing PG&E-PGT 36-inch Pipeline
- Proposed Northwest Alcan Pipeline Project

Basically, three alternatives have been put forward for transporting North Slope gas to market: (1) the Arctic Gas group's system to bring Prudhoe Bay and Mackenzie Delta gas across Canada and to tie into existing networks for both Midwest and West Coast consumers; (2) the El Paso Alaska Company's proposal to move the gas by a pipeline paralleling TAPS to the vicinity of Valdez and thence by LNG tanker to the West Coast; and (3) Alcan Pipeline Company's express pipeline scheme, which parallels TAPS to Fairbanks and then moves across Canada, tieing into existing capacity below Edmonton. These routes are shown on Map II. A detailed review of the merits of each of the competing proposals is beyond the scope of this analysis. Moreover, from the standpoint of the producing companies, who will be selling the resource at the wellhead, any attempt to predict the chosen mode of transportation is not especially useful at this stage, given the considerable uncertainty surrounding the cost estimates of each system and the realizable value of the resource in the final market in the early-to-mid-1980's when gas sales might begin. Suffice it to say, that the procedure now is in place for the appropriate governmental authorities to review these proposals and select the

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Sales not prod.

preferred alternative by late 1977.* On this basis, and allowing for some construction delays, gas sales would probably not begin until 1983 at the earliest.

As to the wellhead price for this gas, the very high transportation costs inherent in all three proposals** should tend to restrain the realizable wellhead value so that the gas can remain competitive with alternative fuels in its final markets. For example, Nahum Litt, the FPC's Administrative Law Judge responsible for reviewing the case for the Commission, recently indicated that if the wellhead price of Prudhoe gas is $1.00 per Mcf and incremental pricing is adopted (i.e., the cost of this gas is borne only by the direct beneficiaries of it), the average city gate price would be $2.41 per Mcf using unescalated cost data. Because such a city gate

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Under the Alaskan Natural Gas Transportation Act signed by former President Ford on October 22, 1976, the FPC is required to forward to the President its recommendation of the preferable route by May 1, 1977. At this point, an Administrative Law Judge has issued a preliminary finding in favor of the Arctic Gas proposal. However, in view of recent modifications in the Alcan proposal and the filing of additional information, the FPC has pledged a complete review of all alternatives prior to making its final recommendation to the President. In turn, upon review of FPC and other input, the President must forward his recommendation to Congress by September 1 (if necessary, this can be delayed to December 1). Congress then will have 60 days to approve or reject the Administration's proposal via a joint House-Senate resolution. If the route selected involves Canada, an expedited approval by this country would be sought under the U.S.-Canadian hydrocarbon pipeline treaty signed in January 1977. In a recent visit to the U.S., Premier Trudeau indicated that a timely decision could be expected.

**Based on unescalated 1975 data, the estimated transportation costs per million Btu's for the Arctic Gas, El Paso, and Alcan proposals will be $1.60, $2.15, and $1.91 per million Btu's, respectively.*

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price would be so substantial, Litt recommended the adoption of rolled-in pricing to spread the cost over all customers of the pipelines receiving Arctic gas. On this basis, the average city gate price would be $1.50 per Mcf for a wellhead price of $1.00 per Mcf. Given the current questions concerning the preferred system, its final cost, and the likely regulatory treatment, these and other estimates of the wellhead price of Alaskan gas that could ultimately prevail remain highly uncertain. In any case, however, it seems unlikely that lower-48 wellhead pricing will apply to Prudhoe Bay gas.

As to the quantity of natural gas production which will be available for sale, the effect of such gas withdrawals on oil recovery is probably the most important consideration. Until oil production actually commences and more data becomes available on the performance of the gas cap as well as the aquifer, judgments in this area must remain rather theoretical. Nevertheless, in preparation for conducting its regulatory responsibilities involving Prudhoe Bay production, the State of Alaska, together with the petroleum engineering consulting firm of H. K. van Poollen and Associates, has developed a fairly sophisticated reservoir model. A series of simulations of various combinations of production modes has suggested that the reservoir's oil recovery factor may be sensitive to gas withdrawal rates in excess of 2 billion cubic feet daily.* While future performance could alter such a finding, at this stage, it currently seems to be the best estimate of the upper limit on gas available for sale vis-à-vis the potential impact of higher withdrawals on oil recovery.

Assumes 5 yrs

**A total of 29 runs were conducted involving various combinations of (1) oil production at rates of 1.2-1.8 million b/d, (2) gas production at rates of 2-4 billion cf/d, and (3) the presence or absence of an aquifer to assist the reservoir drive. As an illustration of the potential sensitivity of oil recovery, these analyses indicated that whereas cumulative oil production might approximate 7.74 billion barrels under a production mode involving a natural aquifer, peak oil production of 1.6 million b/d, water injection of 2.0 million b/d after 4.75 years, and commencement of gas sales at 2 billion cf/d after 6.75 years, oil recovery could be impaired by 680 million barrels if these same conditions are maintained, adjusted for gas sales of 4.0 billion cf/d.*

no Arctic Gas

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Given the unresolved issues outlined above, it is not particularly useful to attempt to develop highly definitive earnings projections for natural gas at this time. Nevertheless, Table 17 presents a rough preliminary indication of the unit profitability that might be expected from gas sales in 1983.

Table 17

Potential Natural Gas Profits
(¢ Per Mcf)

Wellhead price		75.00¢		100.00¢
Royalty @ 12½%	9.38		12.50	
Severance tax @ 10%	6.56		8.75	
DD&A and lifting costs	17.57		17.57	
Total costs		33.51		38.82
Pretax income		41.49		61.18
Income taxes @ 52.9%		21.95		32.36
Net income		19.54¢		28.82¢

With gas sales of 2 billion cf/d, these unit margins would suggest total contributions to profits of $143 and $210 million for the respective cases of 75¢ and $1.00 per Mcf at the wellhead. As a final note, Table 18 shows an estimated breakdown of company ownership of the natural gas reserves in the Prudhoe Bay Unit. It should be noted that the various individual company interests differ meaningfully from the distribution of ownership in the oil rim area.

Table 18

Estimated Natural Gas Reserves
Main Prudhoe Bay Field
(Millions of cubic feet)

	Amount	Approximate % of Total
Arco	8,100	33.9% 42.124
Exxon	8,100	33.9 42.124
Mobil	230	1.0
Phillips	230	1.0
Standard Oil (Ohio)	7,100	29.7 14.818
Other (a)	140	0.5
	23,900	100.0%

(a) Includes Socal and the PLAGM group.

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Company Earnings Profiles

Drawing on the analysis and conclusions of the previous sections, Tables 19 and 20 summarize 1977-1980 earnings prospects for the major Prudhoe Bay reserve owners. The projections are segmented by production, TAPS, and investment tax credits (ITC). Because of the unresolved nature of crude oil pricing and the TAPS tariff – by far the most significant determinants of North Slope earnings – two different pricing and tariff cases are presented in an attempt to bracket the likely range of possibilities in these key areas.

Table 19

North Slope Earnings
Modified ICC Basis Tariff Treatment – 10% Return on Valuation
(In millions except per share)

	1977		1978		1979		1980	
	Case I	Case II	Case I	Case II	Case I	Case II	Case I	Case II
Arco								
Production	$ 49.8	$ 26.2	$249.5	$184.9	$267.4	$215.5	$374.7	$305.9
TAPS	–	–	51.5	51.5	55.0	55.0	47.0	47.0
ITC	132.9	132.9	–	–	20.8	20.8	26.1	26.1
Total	$182.7	$159.1	$301.0	$236.4	$343.2	$291.3	$447.8	$379.0
Per share	$1.58	$1.37	$2.60	$2.04	$2.96	$2.52	$3.87	$3.27
BP								
Equity in Sohio	$ 65.9	$ 37.0	$463.9	$387.6	$411.1	$332.1	$511.7	$418.3
Production	–	–	–	–	–	–	59.6	47.1
TAPS	–	–	38.8	38.8	41.5	41.5	35.4	35.4
ITC	–	–	19.8	19.8	21.1	21.1	18.1	18.1
Total	$ 65.9	$ 37.0	$522.5	$446.2	$473.7	$394.7	$624.8	$518.9
Per share	$0.17	$0.10	$1.35	$1.16	$1.23	$1.02	$1.62	$1.34
Exxon								
Production	$ 47.4	$ 22.9	$238.2	$170.0	$258.6	$201.6	$361.7	$288.8
TAPS	–	–	49.0	49.0	52.4	52.4	44.8	44.8
ITC	128.4	128.4	–	–	20.8	20.8	25.5	25.5
Total	$175.8	$151.3	$287.2	$219.0	$331.8	$274.8	$432.0	$359.1
Per share	$0.39	$0.34	$0.64	$0.49	$0.74	$0.61	$0.96	$0.80
Mobil								
Production	$ 5.2	$ 2.9	$ 26.6	$ 20.2	$ 28.2	$ 23.3	$ 39.0	$ 32.8
TAPS	–	–	12.3	12.3	13.1	13.1	11.2	11.2
ITC	26.4	26.4	–	–	2.1	2.1	4.5	4.5
Total	$ 31.6	$ 29.3	$ 38.9	$ 32.5	$ 43.4	$ 38.5	$ 54.7	$ 48.5
Per share	$0.30	$0.28	$0.37	$0.31	$0.41	$0.36	$0.52	$0.46

(Table 19 continued on following page)

Table 19
(Continued)

North Slope Earnings
Modified ICC Basis Tariff Treatment – 10% Return on Valuation
(In millions except per share)

	1977		1978		1979		1980	
	Case I	Case II	Case I	Case II	Case I	Case II	Case I	Case II
Phillips								
Production	$ 5.0	$ 2.6	$ 25.9	$ 19.1	$ 27.6	$ 22.1	$ 38.3	$ 31.4
TAPS	–	–	4.1	4.1	4.3	4.3	3.7	3.7
ITC	11.4	11.4	–	–	2.1	2.1	2.3	2.3
Total	$ 16.4	$ 14.0	$ 30.0	$ 23.2	$ 34.0	$ 28.5	$ 44.3	$ 37.4
Per share	$0.21	$0.18	$0.39	$0.30	$0.44	$0.37	$0.58	$0.49
Socal								
Production	$ 2.1	$ 1.1	$ 9.9	$ 7.3	$ 10.5	$ 8.4	$ 14.4	$ 11.8
TAPS	–	–	–	–	–	–	–	–
ITC	1.5	1.5	–	–	0.8	0.8	0.5	0.5
Total	$ 3.6	$ 2.6	$ 9.9	$ 7.3	$ 11.3	$ 9.2	$ 14.9	$ 12.3
Per share	$0.02	$0.02	$0.06	$0.04	$0.07	$0.05	$0.09	$0.07
Sohio								
Production	$119.2	$ 55.7	$593.5	$414.0	$652.4	$500.0	$843.7	$666.1
TAPS	–	–	81.7	81.7	87.3	87.3	74.6	74.6
ITC	99.1	66.9	220.4	252.6	53.9	53.9	54.6	54.6
Total	$218.3	$122.6	$895.6	$748.3	$793.6	$641.2	$972.9	$795.3
Per share	$5.34	$3.00	$14.88	$12.43	$13.16	$10.63	$15.90	$13.00

Case I: *World price.*
Case II: *Upper tier controlled price.*

Table 20

North Slope Earnings
Elkins Act Tariff Treatment – 7% Return on Valuation
(In millions except per share)

	1977		1978		1979		1980	
	Case I	Case II	Case I	Case II	Case I	Case II	Case I	Case II
Arco								
Production	$ 49.8	$ 26.2	$175.0	$109.9	$197.3	$145.1	$302.5	$230.0
TAPS	–	–	139.0	139.0	137.3	137.3	135.8	135.8
ITC	132.9	132.9	–	–	20.8	20.8	26.1	26.1
Total	$182.7	$159.1	$314.0	$248.9	$355.4	$303.2	$464.4	$391.9
Per share	$1.58	$1.37	$2.71	$2.15	$3.07	$2.62	$4.01	$3.38
BP								
Equity in Sohio	$ 65.9	$ 37.0	$435.3	$358.1	$383.7	$305.3	$491.6	$395.4
Production	–	–	–	–	–	–	47.1	34.2
TAPS	–	–	104.8	104.8	103.5	103.5	102.4	102.4
ITC	–	–	53.4	52.8	52.8	52.8	48.5	42.1
Total	$ 65.9	$ 37.0	$593.5	$515.7	$540.0	$461.6	$689.6	$574.1
Per share	$0.17	$0.10	$1.54	$1.34	$1.40	$1.20	$1.79	$1.49

(Table 20 continued on following page)

Table 20
(Continued)

North Slope Earnings
Elkins Act Tariff Treatment – 7% Return on Valuation
(In millions except per share)

	1977		1978		1979		1980	
	Case I	Case II	Case I	Case II	Case I	Case II	Case I	Case II
Exxon								
Production	$ 47.4	$ 22.9	$163.4	$ 94.5	$188.1	$131.3	$288.9	$213.0
TAPS	–	–	132.4	132.4	130.7	130.7	129.3	129.3
ITC	128.4	128.4	–	–	20.8	20.8	25.5	25.5
Total	$175.8	$151.3	$295.8	$226.9	$339.6	$282.8	$443.7	$367.8
Per share	$0.39	$0.34	$0.66	$0.51	$0.76	$0.63	$0.99	$0.82
Mobil								
Production	$ 5.2	$ 2.9	$ 19.0	$ 12.6	$ 21.2	$ 16.1	$ 31.6	$ 24.9
TAPS	–	–	33.1	33.1	32.7	32.7	32.3	32.3
ITC	26.4	26.4	–	–	2.1	2.1	4.5	4.5
Total	$ 31.6	$ 29.3	$ 52.1	$ 45.7	$ 56.0	$ 50.9	$ 68.4	$ 61.7
Per share	$0.30	$0.28	$0.49	$0.43	$0.53	$0.48	$0.65	$0.58
Phillips								
Production	$ 5.0	$ 2.6	$ 18.3	$ 11.4	$ 20.4	$ 14.9	$ 30.9	$ 23.7
TAPS	–	–	11.0	11.0	10.8	10.8	10.7	10.7
ITC	11.4	11.4	–	–	2.1	2.1	2.3	2.3
Total	$ 16.4	$ 14.0	$ 29.3	$ 22.4	$ 33.3	$ 27.8	$ 43.9	$ 36.7
Per share	$0.21	$0.18	$0.38	$0.29	$0.43	$0.36	$0.57	$0.48
Socal								
Production	$ 2.1	$ 1.1	$ 7.0	$ 4.3	$ 7.8	$ 5.7	$ 11.6	$ 8.9
TAPS	–	–	–	–	–	–	–	–
ITC	1.5	1.5	–	–	0.8	0.8	0.5	0.5
Total	$ 3.6	$ 2.6	$ 7.0	$ 4.3	$ 8.6	$ 6.5	$ 12.1	$ 9.4
Per share	$0.02	$0.02	$0.04	$0.03	$0.05	$0.04	$0.07	$0.06
Sohio								
Production	$119.2	$ 55.7	$399.3	$218.2	$468.9	$317.5	$664.4	$481.6
TAPS	–	–	220.6	220.6	217.9	217.9	215.6	215.6
ITC	99.1	66.9	220.4	252.6	53.9	53.9	54.6	54.6
Total	$218.3	$122.6	$840.3	$691.4	$740.7	$589.3	$934.6	$751.8
Per share	$5.34	$3.00	$13.96	$11.49	$12.28	$9.77	$15.27	$12.28

Case I: World price.
Case II: Upper tier controlled price.

While the Tables are fairly self-explanatory, several clarifying comments are in order. In developing our earnings projections for second-half 1977, we have assumed a cost-of-service (breakeven) tariff. Recognizing that the pipeline tariff is inversely correlated with pipeline throughput, shipper-owners of TAPS are likely to adopt a tariff strategy in the initial startup period of line operation partly designed to assuage (but certainly not eliminate) the State of Alaska's concern regarding the effect of an inordinately high initial tariff posting on its take at the wellhead. Passage of either of the two competing oil production tax proposals now

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before the Alaskan legislature would further reinforce the desirability of preserving a "reasonable" wellhead value. Since production earnings will probably not be booked by the parent companies until the oil actually arrives on the West Coast, 1977 volumes must therefore be segregated between the amounts going into inventory and final sales. Allowing for inventory buildup and the voyage time required between Valdez and the West Coast, the writers assume that production earnings would not be reflected on a book basis until after Labor Day.

Appendix D shows the derivation of ITC benefits related to the Prudhoe Bay development project. Book ITC is taken into earnings the year it becomes available. However, for BP and Sohio, which are constrained during 1977 and 1978 by the statutory limit on ITC ($25,000 plus 50% of taxes payable), the accrued benefits are taken down as permitted by earnings. As the figures in Appendix D indicate, the absolute size and significant year-to-year fluctuations in ITC cannot be ignored in formulating overall earnings expectations for the big North Slope interest holders.

Besides production and TAPS, marine transportation is a third profit center in the integrated movement of North Slope oil to markets of destination. Lack of available information on tanker requirements, and the age, cost, and ownership characteristics of each company's vessels destined for the Alaskan trade precludes reliable forecasts of tanker profits by company. Nevertheless, based on our conversations with the companies, a 10¢-15¢ per barrel profit component probably will be included within the 70¢ per barrel tanker charge from Valdez-Long Beach on owned and long-term-chartered vessels. As a general observation, Atlantic Richfield seems to enjoy a superior marine transportation position relative to Exxon and Sohio, given its 100% coverage of requirements by owned and long-term-chartered vessels, together with the average size and construction cost of its fleet.

As alluded to earlier in the discussion of pipeline issues and economics, Sohio's current interest in TAPS will make the company a substantial net purchaser of pipeline transportation services once Prudhoe Bay output commences. As such, Sohio, unlike Arco and Exxon, would be relatively immune to an adverse earnings impact if a return on equity approach to ratemaking is ultimately applied to TAPS. As Tables 19 and 20 show, Sohio's total North Slope earnings are actually *higher* under the return on equity tariff treatment vis-à-vis the *Elkins Act*. However, two factors could tend to lessen any absolute advantage to be enjoyed by Sohio: (1) a possible increase in its interest in TAPS in any future realignment of company equities; and (2) compared to our composite case interest rate assumption of 9%, Sohio's somewhat higher cost of debt would tend to result in a higher pipeline tariff (and a lower wellhead price) and lower GAAP pipeline earnings than our analysis would indicate. On the other hand, because of a lower-than-average cost of debt, the earnings penalty ascribable to Arco and Exxon under the modified ICC basis tariff treatment may be slightly overstated. SOHIO on our side.

Beyond 1980, North Slope earnings should continue to expand, reflecting full-year attainment of peak production of 1.6 million b/d from the main (Sadlerochit) reservoir in 1981, the likelihood of further price increases, development of Kuparuk and Lisburne reserves, and 1983 startup of natural gas production. Arco and Exxon will be the main beneficiaries of natural gas production, whereas Arco and BP, based on their sizable acreage holdings (particularly in the Kuparuk trend west of Prudhoe Bay), should garner the bulk of any eventual Kuparuk and Lisburne production. Appendix F provides some preliminary profit projections for the Kuparuk and Lisburne formations. Although the unit profitability

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numbers are far lower than those for the main Prudhoe Bay field, development of these currently marginal reserves, by increasing pipeline throughput, will enhance the economics of other North Slope production.

Granted, this *Industry Review* has detailed many of the uncertainties affecting the realization of North Slope earnings. On the positive side, the uniqueness of long-lived Prudhoe Bay reserves cannot be emphasized enough in today's industry environment. With most companies facing the difficult task of replacing depleted low-cost reserves, access to substantial North Slope reserves affords the luxury of a stable underlying basic cash flow on which to launch *new* corporate investments for future growth.

WAINWRIGHT SECURITIES INC.
Paul R. Leibman
Thomas A. Petrie

Computer Applications
Richard C. Marks

(See Appendices on following pages)

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APPENDIX A

WEST COAST SUPPLY/DEMAND – BACKGROUND DATA

Projected P.A.D. District V Product Demand
(In millions of b/d)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
FEA				2.4		2.6			3.0
Arco		2.7				3.1			
Exxon	2.4	2.6	2.8	2.9	3.0	3.0	3.1	3.2	3.3
Kitimat (Ashland)	–	–	–	–	–	–	–	–	–
Sohio (Pace)	2.8			3.2	2.9	2.9			3.2
Socal	2.5	2.6	2.7	2.7	2.8				3.2

Projected Refining Throughput P.A.D. District V
(In millions of b/d)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
FEA	2.1			2.3					
Arco									
Exxon	2.5	2.6	2.6	2.6	2.6	2.7	2.9	3.1	3.2
Kitimat (Ashland)	2.5	2.6	2.6	2.6	2.7	2.8	2.8	2.9	2.9
Sohio (Pace)		2.4		2.5					
Socal		2.6		2.6					

Projected West Coast (P.A.D. District V) Production Other than North Slope
(In millions of b/d)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
FEA		1.2		1.3					1.7
Arco	1.0	1.0	1.0	0.9	1.0	1.0	1.1	1.4	1.6
Exxon	1.1	1.1	1.2	1.2	1.2	1.3			
Kitimat (Ashland)	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.4	1.4
Sohio (Pace)		1.2-1.4		1.4		1.3			
Socal		1.0		1.1					

Projected Imports of Crude Oil Into P.A.D. District V
(In millions of b/d)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
FEA									
High case	0.6	0.5		0.5		0.5			
Low case	0.6	0.5		0.3		0.3			
FPC		0.6				0.5			
Exxon	0.8	0.6	0.5	0.6	0.5	0.5	0.4	0.3	0

(See Appendix B on following pages)

APPENDIX B

DCF Economics – TAPS (a)
(In millions)

	Operating Revenues	Operating Costs	Property Taxes	Income Taxes State	Income Taxes Federal (b)	Capital Expenditures	Borrowings	Repayments	Net Cash Flow (c)
1969						$ 35			($ 35)
1970						180			(180)
1971						109			(109)
1972						49			(49)
1973						47			(47)
1974					($ 46)	857	$1,247		(811)
1975					(200)	2,772	2,813		(2,572)
1976					(406)	2,698	2,958		(2,292)
1977	$ 583	$ 75			(620)	953	1,082	$ 159	175
1978	1,854	175	$ 146		(16)	200	180	318	1,349
1979	1,874	184	149		(49)	400	360	318	1,190
1980	1,856	213	147		(120)	100	90	318	1,516
1981	2,076	224	150	$ 16	42	400	360	318	1,244
1982	2,155	250	145	30	138			318	1,592
1983	2,188	262	139	41	188			350	1,558
1984	2,228	275	133	53	243			368	1,524
1985	2,273	289	128	65	299			369	1,492
1986	2,319	304	122	77	356			368	1,460
1987	2,362	316	117	89	413			369	1,427
1988	2,405	326	111	102	470			368	1,396
1989	2,450	336	106	114	528			369	1,366
1990	2,499	347	100	127	588			368	1,337
1991	2,550	358	95	140	648			369	1,309
1992	2,613	376	89	154	711			368	1,283
1993	2,678	394	83	167	774			369	1,260
1994	2,748	414	78	181	839			368	1,236
1995	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			[illegible]	[illegible]
1996	2,894	457	67	205	[illegible]			368	1,230
1997	2,970	479	61	211	977			369	1,242
1998	3,049	503	56	220	1,018			368	1,252
1999	3,131	528	50	229	1,060			369	1,264
2000	3,214	554	45	238	1,102			368	1,275
2001	3,301	582	39	247	1,144			369	1,289
2002	3,390	611	33	257	1,187			358	1,302
2003	3,405	642	28	257	1,190				1,288
2004	3,462	674	22	260	1,203				1,303
2005	3,521	708	17	263	1,216				1,317
Totals	$74,868	$11,291	$2,528	$3,935	$16,712	$8,800	$9,090	$9,090	$31,602

(a) *1977=100.*

(b) *Tax benefits accruing to the TAPS owners from investment tax credits and expensing of interest incurred during construction are reflected as a reduction in Federal income tax liability in the appropriate year.*

(c) *Excludes borrowings and repayments.*

(Appendix B continued on following page)

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APPENDIX B
(Continued)

DCF Economics – Prudhoe Bay Field (a)
(In millions)

	Oil Revenues	Lifting Costs	Royalty	Production Taxes	Property Taxes	Income Taxes State	Income Taxes Federal (b)	Capital and Exploratory Expenditures	Borrowings	Repayments	Net Cash Flow (c) Oil	Net Cash Flow (c) Natural Gas (d)	Net Cash Flow (c) Combined
1959								$ 2			($ 2)		($ 2)
1960								1			(1)		(1)
1961								1			(1)		(1)
1962							($ 1)	8			(7)		(7)
1963							(4)	18			(14)		(14)
1964							(12)	31			(19)		(19)
1965							(7)	26			(19)		(19)
1966							(3)	7			(4)		(4)
1967							(4)	12			(8)		(8)
1968							(5)	14			(9)		(9)
1969							(23)	418			(395)		(395)
1970							(21)	90			(69)		(69)
1971							(11)	51			(40)		(40)
1972							(4)	23			(19)		(19)
1973							(3)	27			(24)		(24)
1974							(12)	157	$139		(145)		(145)
1975							(58)	781	292		(723)		(723)
1976					$220		(261)	1,215	462		(1,174)		(1,174)
1977	$ 982	$ 91	$ 123	$ 43	270	$ 33	(130)	799	108		(247)		(247)
1978	3,916	149	490	165	61	230	1,029	545		$125	1,247		1,247
1979	4,157	158	520	171	70	245	1,031	549		125	1,413		1,413
1980	5,608	166	701	355	83	340	1,513	748		125	1,702		1,702
1981	6,734	196	842	561	105	403	1,867	1,087		125	1,673		1,673
1982	7,142	210	893	590	123	421	1,947	1,074		125	1,884		1,884
1983	7,539	222	942	619	146	440	2,038	1,131		125	2,001	$268	2,269
1984	7,948	228	994	648	164	468	2,165	1,075		125	2,206	294	2,500
1975	8,375	239	1,047	677	175	505	2,336	587		126	2,809	336	3,145
1986	8,813	251	1,102	707	175	552	2,555				3,471	362	3,833
1987	8,847	259	1,106	703	174	566	2,619				3,420	369	3,789
1988	8,573	268	1,072	668	179	556	2,575				3,255	376	3,631
1989	8,318	276	1,040	636	177	548	2,538				3,103	417	3,520
1990	8,094	287	1,012	603	176	539	2,496				2,981	392	3,373

(Appendix B continued on following page)

APPENDIX B
(Continued)

DCF Economics – Prudhoe Bay Field (a)
(In millions)

	Oil Revenues	Lifting Costs	Royalty	Production Taxes	Property Taxes	Income Taxes State	Income Taxes Federal (b)	Capital and Exploratory Expenditures	Borrowings	Repayments	Net Cash Flow (c) Oil	Net Cash Flow (c) Natural Gas (d)	Net Cash Flow (c) Combined
1991	$ 7,849	$ 295	$ 981	$ 573	$ 174	$ 528	$ 2,445				$ 2,853	$ 401	$ 3,244
1992	7,077	302	885	499	171	477	2,209				2,534	411	2,945
1993	6,421	308	803	434	170	434	2,009				2,263	392	2,655
1994	5,834	319	729	377	166	394	1,825				2,024	373	2,397
1995	5,326	330	666	325	161	359	1,662				1,823	356	2,179
1996	4,835	342	604	284	156	323	1,495				1,631	308	1,939
1997	4,457	354	557	250	150	295	1,365				1,486	331	1,817
1998	4,027	367	503	212	143	263	1,216				1,323	321	1,644
1999	3,541	381	431	170	135	227	1,052				1,145	272	1,417
2000	3,100	396	388	131	127	193	893				972	260	1,232
2001	2,821	413	353	107	117	172	795				864	249	1,113
2002	2,508	431	314	80	104	148	686				745	237	982
2003	2,286	451	286	60	92	131	606				660	224	884
2004	2,024	470	253	37	77	111	515				561	212	773
2005	1,864	492	233	14	67	98	455				495	201	696
Totals	$159,016	$8,651	$19,870	$10,7[illegible]9	$4,308	$9,999	$45,378	$10,477	$1,001	$1,001	$49,624	$7,362	$56,986

(a) 1977=100.

(b) In addition to investment tax credits, tax benefits accruing to the North Slope producers from expensing of intangibles, interest incurred during construction, and the ad valorem tax on in-place oil and gas reserves are reflected as a reduction in Federal income tax liability in the appropriate year.

(c) Excludes borrowings and repayments.

(d) Whereas a separate cash flow analysis was performed for natural gas, for ease of presentation, natural gas is shown each year as a net cash flow amount.

DCF Rates of Return:

TAPS	10.6%
Prudhoe Bay	19.1
Combined	15.7

(See Appendix C on following pages)

Appendix C

<u>Prudhoe Bay Field -- Main (Sadlerochit) Reservoir</u>
<u>Derivation of Unit Producing Profits</u>
<u>Market of Destination -- Japan (a)</u>

Case 1: World Price

	1978		1979		1980		1985		1990	
Production Rate (millions of b/d)		1.20		1.20		1.42		1.60		1.27
Landed Crude Price		$13.13		$13.72		$14.34		$17.87		$22.27
Marine Transportation		0.41		0.42		0.43		0.50		0.58
TAPS Liability Fund		0.05		0.05		0.05		0.00		0.00
Pipeline Transportation		0.00		0.00		0.00		0.00		0.00
Valdez Netback		12.68		13.25		13.86		17.37		21.69
TAPS Tariff		4.23		4.28		3.58		3.74		5.14
Wellhead Price		8.45		8.97		10.28		13.63		16.55
Royalty @ 12.5%	1.06		1.12		1.28		1.70		2.07	
Production Taxes	0.75		0.78		0.85		1.10		1.24	
Property Taxes	0.14		0.16		0.16		0.30		0.38	
Lifting Costs	0.34		0.36		0.32		0.41		0.62	
Interest Charges	0.22		0.20		0.14		0.03		0.03	
Depr., Depl., and Amort.	0.35		0.40		0.46		1.12		1.19	
Total Costs		2.86		3.02		3.22		4.67		5.52
Pretax Profit		5.59		5.95		7.05		8.96		11.03
Income Taxes										
- State @ 9.4%	0.53		0.56		0.66		0.84		1.04	
- Federal @ 48%	2.43		2.59		3.07		3.90		4.80	
Total Income Taxes		2.96		3.15		3.73		4.74		5.83
Net Profit		$ 2.63		$ 2.80		$ 3.32		$ 4.22		$ 5.20
TAPS Profit		0.56		0.60		0.43		0.72		1.25
Integrated Profit		$ 3.19		$ 3.40		$ 3.75		$ 4.94		$ 6.45

(a) Totals may not add due to rounding.

(Appendix C continued on following pages)

Appendix C (con't)

Prudhoe Bay Field -- Main (Sadlerochit) Reservoir
Derivation of Unit Producing Profits
Market of Destination -- Puget Sound (a)

Case I: World Price

	1978		1979		1980		1985		1990	
Production Rate (millions of b/d)		1.20		1.20		1.42		1.60		1.27
Landed Crude Price		$13.87		$14.50		$15.15		$18.88		$23.53
Marine Transportation		0.51		0.52		0.54		0.62		0.72
TAPS Liability Fund		0.05		0.05		0.05		0.00		0.00
Pipeline Transportation		0.00		0.00		0.00		0.00		0.00
Valdez Netback		13.32		13.93		14.56		18.26		22.80
TAPS Tariff		4.23		4.28		3.58		3.74		5.14
Wellhead Price		9.09		9.65		10.98		14.52		17.66
Royalty @ 12.5%	1.14		1.21		1.37		1.81		2.21	
Production Taxes	0.76		0.80		0.91		1.18		1.32	
Property Taxes	0.14		0.16		0.16		0.30		0.38	
Lifting Costs	0.34		0.36		0.32		0.41		0.62	
Interest Charges	0.22		0.20		0.14		0.03		0.03	
Depr., Depl., and Amort.	0.35		0.40		0.46		1.12		1.19	
Total Costs		2.94		3.12		3.37		4.85		5.75
Pretax Profit		6.14		6.52		7.61		9.66		11.92
Income Taxes										
- State @ 9.4%	0.58		0.61		0.72		0.91		1.12	
- Federal @ 48%	2.67		2.84		3.31		4.20		5.18	
Total Income Taxes		3.25		3.45		4.03		5.11		6.30
Net Profit		$ 2.89		$ 3.07		$ 3.59		$ 4.55		$ 5.62
TAPS Profit		0.56		0.60		0.43		0.72		1.25
Integrated Profit		$ 3.45		$ 3.67		$ 4.02		$ 5.27		$ 6.87

(a) Totals may not add due to rounding.

Appendix C (con't)

Prudhoe Bay Field -- Main (Sadlerochit) Reservoir
Derivation of Unit Producing Profits
Market of Destination -- Puget Sound (a)

Case II: Controlled Price

	1978		1979		1980		1985		1990	
Production Rate (millions of b/d)		1.20		1.20		1.42		1.60		1.27
Landed Crude Price		$12.19		$13.17		$13.67		$17.45		$22.27
Marine Transportation		0.51		0.52		0.54		0.62		0.72
TAPS Liability Fund		0.05		0.05		0.05		0.00		0.00
Pipeline Transportation		0.00		0.00		0.00		0.00		0.00
Valdez Netback		11.63		12.60		13.08		16.83		21.55
TAPS Tariff		4.23		4.28		3.58		3.74		5.14
Wellhead Price		7.40		8.32		9.50		13.09		16.41
Royalty @ 12.5%	0.93		1.04		1.19		1.64		2.05	
Production Taxes	0.75		0.78		0.82		1.06		1.22	
Property Taxes	0.14		0.16		0.16		0.30		0.38	
Lifting Costs	0.34		0.36		0.32		0.41		0.62	
Interest Charges	0.22		0.20		0.14		0.03		0.03	
Depr., Depl., and Amort.	0.35		0.40		0.46		1.12		1.19	
Total Costs		2.72		2.94		3.10		4.56		5.49
Pretax Profit		4.68		5.38		6.40		8.53		10.91
Income Taxes										
- State @ 9.4%	0.44		0.51		0.60		0.80		1.03	
- Federal @ 48%	2.03		2.34		2.79		3.71		4.75	
Total Income Taxes		2.47		2.84		3.39		4.51		5.77
Net Profit		$ 2.20		$ 2.53		$ 3.02		$ 4.02		$ 5.14
TAPS Profit		0.56		0.60		0.43		0.72		1.25
Integrated Profit		$ 2.76		$ 3.13		$ 3.45		$ 4.74		$ 6.39

(a) Totals may not add due to rounding.

Appendix C (con't)

Prudhoe Bay Field -- Main (Sadlerochit) Reservoir
Derivation of Unit Producing Profits
Market of Destination -- San Francisco (a)

Case 1: World Price

	1978		1979		1980		1985		1990	
Production Rate (millions of b/d)		1.20		1.20		1.42		1.60		1.27
Landed Crude Price		$13.99		$14.62		$15.28		$19.04		$23.72
Marine Transportation		0.81		0.84		0.86		1.00		1.16
TAPS Liability Fund		0.05		0.05		0.09		0.00		0.00
Pipeline Transportation		0.00		0.00		0.00		0.00		0.00
Valdez Netback		13.13		13.73		14.36		18.04		22.57
TAPS Tariff		4.23		4.28		3.58		3.74		5.14
Wellhead Price		8.90		9.45		10.78		14.30		17.43
Royalty @ 12.5%	1.11		1.18		1.35		1.79		2.18	
Production Taxes	0.75		0.78		0.89		1.16		1.30	
Property Taxes	0.14		0.16		0.16		0.30		0.38	
Lifting Costs	0.34		0.36		0.32		0.41		0.62	
Interest Charges	0.22		0.20		0.14		0.03		0.03	
Depr., Depl., and Amort.	0.35		0.40		0.46		1.12		1.19	
Total Costs		2.91		3.08		3.33		4.81		5.70
Pretax Profit		5.99		6.37		7.46		9.49		11.73
Income Taxes										
- State @ 9.4%	0.56		0.60		0.70		0.89		1.10	
- Federal @ 48%	2.60		2.77		3.24		4.13		5.10	
Total Income Taxes		3.17		3.37		3.94		5.02		6.20
Net Profit		$ 2.82		$ 3.00		$ 3.51		$ 4.47		$ 5.53
TAPS Profit		0.56		0.60		0.43		0.72		1.25
Integrated Profit		$ 3.38		$ 3.60		$ 3.94		$ 5.19		$ 6.78

(a) Totals may not add due to rounding.

Appendix C (con't)

Prudhoe Bay Field -- Main (Sadlerochit) Reservoir
Derivation of Unit Producing Profits
Market of Destination -- San Francisco (a)

Case II: Controlled Price

	1978		1979		1980		1985		1990	
Production Rate (millions of b/d)	1.20		1.20		1.42		1.60		1.27	
Landed Crude Price		$12.19		$13.17		$13.67		$17.45		$22.27
Marine Transportation		0.81		0.84		0.86		1.00		1.16
TAPS Liability Fund		0.05		0.05		0.05		0.00		0.00
Pipeline Transportation		0.00		0.00		0.00		0.00		0.00
Valdez Netback		11.33		12.28		12.76		16.45		21.11
TAPS Tariff		4.23		4.28		3.58		3.74		5.14
Wellhead Price		7.10		8.00		9.18		12.71		15.97
Royalty @ 12.5%	0.89		1.00		1.15		1.59		2.00	
Production Taxes	0.75		0.78		0.82		1.03		1.21	
Property Taxes	0.14		0.16		0.16		0.30		0.38	
Lifting Costs	0.34		0.36		0.32		0.41		0.62	
Interest Charges	0.22		0.20		0.14		0.03		0.03	
Depr., Depl., and Amort.	0.35		0.40		0.46		1.12		1.19	
Total Costs		2.69		2.90		3.06		4.48		5.42
Pretax Profit		4.41		5.10		6.12		8.23		10.55
Income Taxes										
- State @ 9.4%	0.41		0.48		0.58		0.77		0.99	
- Federal @ 48%	1.92		2.22		2.66		3.58		4.59	
Total Income Taxes		2.33		2.70		3.24		4.35		5.58
Net Profit		$ 2.08		$ 2.40		$ 2.88		$ 3.88		$ 4.97
TAPS Profit		0.56		0.60		0.43		0.72		1.25
Integrated Profit		$ 2.64		$ 3.00		$ 3.31		$ 4.60		$ 6.22

(a) Totals may not add due to rounding.

Appendix C (con't)

Prudhoe Bay Field -- Main (Sadlerochit) Reservoir
Derivation of Unit Producing Profits
Market of Destination -- Houston (a)

Case I: World Price

	1978		1979		1980		1985		1990	
Production Rate (millions of b/d)	1.20		1.20		1.42		1.60		1.27	
Landed Crude Price		$14.19		$14.83		$15.49		$19.31		$24.06
Marine Transportation		2.49		2.56		0.75		0.87		1.01
TAPS Liability Fund		0.05		0.05		0.05		0.00		0.00
Pipeline Transportation		0.00		0.00		1.40		1.51		1.63
Valdez Netback		11.65		12.21		13.29		16.92		21.42
TAPS Tariff		4.23		4.28		3.58		3.74		5.14
Wellhead Price		7.42		7.93		9.71		13.18		16.28
Royalty @ 12.5%	0.93		0.99		1.21		1.65		2.04	
Production Taxes	0.75		0.78		0.82		1.07		1.22	
Property Taxes	0.14		0.16		0.16		0.30		0.38	
Lifting Costs	0.34		0.36		0.32		0.41		0.62	
Interest Charges	0.22		0.20		0.14		0.0[illegible]		0.03	
Depr., Depl., and Amort.	0.35		0.40		0.46		1.12		1.19	
Total Costs		2.73		2.89		3.12		4.58		5.47
Pretax Profit		4.69		5.04		6.58		8.61		10.81
Income Taxes										
- State @ 9.4%	0.44		0.47		0.62		0.81		1.02	
- Federal @ 48%	2.04		2.19		2.86		3.74		4.70	
Total Income Taxes		2.48		2.67		3.48		4.55		5.72
Net Profit		$ 2.21		$ 2.38		$ 3.10		$ 4.05		$ 5.09
TAPS Profit		0.56		0.60		0.43		0.72		1.25
Integrated Profit		$ 2.77		$ 2.98		$ 3.53		$ 4.77		$ 6.34

(a) Totals may not add due to rounding.

Appendix C (con't)

Prudhoe Bay Field -- Main (Sadlerochit) Reservoir
Derivation of Unit Producing Profits
Market of Destination -- Houston (a)

Case II: Controlled Price

	1978		1979		1980		1985		1990	
Production Rate (millions of b/d)	1.20		1.20		1.42		1.60		1.27	
Landed Crude Price		$12.19		$13.17		$13.67		$17.45		$22.27
Marine Transportation		2.49		2.56		0.75		0.87		1.01
TAPS Liability Fund		0.05		0.05		0.05		0.00		0.00
Pipeline Transportation		0.00		0.00		1.40		1.51		1.63
Valdez Netback		9.65		10.56		11.46		15.07		19.63
TAPS Tariff		4.23		4.28		3.58		3.74		5.14
Wellhead Price		5.42		6.28		7.88		11.33		14.49
Royalty @ 12.5%	0.68		0.78		0.99		1.42		1.81	
Production Taxes	0.75		0.78		0.82		1.03		1.21	
Property Taxes	0.14		0.16		0.16		0.30		0.38	
Lifting Costs	0.34		0.36		0.32		0.41		0.62	
Interest Charges	0.22		0.20		0.14		0.03		0.03	
Depr., Depl., and Amort.	0.35		0.40		0.46		1.12		1.19	
Total Costs		2.48		2.68		2.90		4.30		5.24
Pretax Profit		2.95		3.59		4.99		7.02		9.25
Income Taxes										
- State @ 9.4%	0.28		0.34		0.47		0.66		0.87	
- Federal @ 48%	1.28		1.56		2.17		3.05		4.02	
Total Income Taxes		1.56		1.90		2.64		3.71		4.89
Net Profit		$ 1.39		$ 1.69		$ 2.35		$ 3.31		$ 4.36
TAPS Profit		0.56		0.60		0.43		0.72		1.25
Integrated Profit		$ 1.95		$ 2.29		$ 2.78		$ 4.03		$ 5.61

(a) Totals may not add due to rounding.

Appendix C (con't)

Prudhoe Bay Field -- Main (Sadlerochit) Reservoir
Derivation of Unit Producing Profits
Market of Destination -- Chicago (a)

Case I: World Price

	1978		1979		1980		1985		1990	
Production Rate (millions of b/d)	1.20		1.20		1.42		1.60		1.27	
Landed Crude Price		$14.47		$15.12		$15.80		$19.69		$24.54
Marine Transportation		0.51		0.52		0.54		0.62		0.72
TAPS Liability Fund		0.05		0.05		0.05		0.00		0.00
Pipeline Transportation		1.32		1.34		1.02		1.10		1.18
Valdez Netback		12.59		13.21		14.20		17.97		22.63
TAPS Tariff		4.23		4.28		3.58		3.74		5.14
Wellhead Price		8.36		8.93		10.62		14.23		17.49
Royalty @ 12.5%	1.05		1.12		1.33		1.78		2.19	
Production Taxes	0.75		0.78		0.88		1.15		1.31	
Property Taxes	0.14		0.16		0.16		0.30		0.38	
Lifting Costs	0.34		0.36		0.32		0.41		0.62	
Interest Charges	0.22		0.20		0.14		0.03		0.03	
Depr., Depl., and Amort.	0.35		0.40		0.46		1.12		1.19	
Total Costs		2.84		3.01		3.29		4.79		5.71
Pretax Profit		5.52		5.91		7.32		9.44		11.78
Income Taxes										
- State @ 9.4%	0.52		0.56		0.69		0.89		1.11	
- Federal @ 48%	2.40		2.57		3.18		4.10		5.12	
Total Income Taxes		2.92		3.13		3.87		4.99		6.23
Net Profit		$ 2.60		$ 2.79		$ 3.45		$ 4.45		$ 5.55
TAPS Profit		0.56		0.60		0.43		0.72		1.25
Integrated Profit		$ 3.16		$ 3.39		$ 3.88		$ 5.17		$ 6.80

(a) Totals may not add due to rounding.

Appendix C (con't)

Prudhoe Bay Field -- Main (Sadlerochit) Reservoir
Derivation of Unit Producing Profits
Market of Destination -- Chicago (a)

Case II: Controlled Price

	1978		1979		1980		1985		1990	
Production Rate (millions of b/d)		1.20		1.20		1.42		1.60		1.27
Landed Crude Price		$12.19		$13.17		$13.67		$17.45		$22.27
Marine Transportation		0.51		0.52		0.54		0.62		0.72
TAPS Liability Fund		0.05		0.05		0.05		0.00		0.00
Pipeline Transportation		1.32		1.34		1.02		1.10		1.18
Valdez Netback		10.31		11.26		12.06		15.73		20.37
TAPS Tariff		4.23		4.28		3.58		3.74		5.14
Wellhead Price		6.08		6.98		8.48		11.99		15.23
Royalty @ 12.5%	0.76		0.87		1.06		1.50		1.90	
Production Taxes	0.75		0.78		0.82		1.03		1.21	
Property Taxes	0.14		0.16		0.16		0.30		0.38	
Lifting Costs	0.34		0.36		0.32		0.41		0.62	
Interest Charges	0.22		0.20		0.14		0.03		0.03	
Depr., Depl., and Amort.	0.35		0.40		0.46		1.12		1.19	
Total Costs		2.56		2.77		2.97		4.39		5.33
Pretax Profit		3.52		4.21		5.51		7.60		9.90
Income Taxes										
- State @ 9.4%	0.33		0.40		0.52		0.71		0.93	
- Federal @ 48%	1.53		1.83		2.40		3.31		4.30	
Total Income Taxes		1.86		2.22		2.92		4.02		5.23
Net Profit		$ 1.66		$ 1.98		$ 2.60		$ 3.58		$ 4.66
TAPS Profit		0.56		0.60		0.43		0.72		1.25
Integrated Profit		$ 2.22		$ 2.58		$ 3.03		$ 4.30		$ 5.91

(a) Totals may not add due to rounding.

(See Appendix D on following page)

APPENDIX D

Derivation of North Slope Investment Tax Credits
(In millions)

Year	1969	1970	1971	1972	1973	1974	1975	1976	1977(e)	1978(e)	1979(e)	1980(e)
Capital expenditures:												
TAPS	$35.0	$180.0	$109.0	$49.0	$47.0	$ 857.0	$2,772.0	$2,698.0	$ 953.0	$200.0	$400.0	$100.0
Field development	20.0	82.0	51.0	23.0	27.0	157.0	781.0	1,215.0	799.2	544.5	549.4	748.0
Total	$55.0	$262.0	$160.0	$72.0	$74.0	$1,014.0	$3,553.0	$3,913.0	$1,752.2	$744.5	$949.4	$848.0
Expenditures qualifying for ITC (a):												
TAPS	$31.5	$162.0	$ 98.1	$44.1	$42.3	$ 771.3	$2,494.8	$2,428.2	$ 857.7	$180.0	$360.0	$ 90.0
Field development	10.0	46.0	28.0	15.0	21.0	145.0	732.0	1,097.0	613.9	559.4	454.9	631.0
Total	$41.5	$208.0	$126.1	$59.1	$63.3	$ 916.3	$3,226.8	$3,525.2	$1,471.6	$739.4	$814.9	$721.0
ITC rate	7%	7%	7%	7%	7%	7%	10%	10%	10%	10%	10%	10%
Accumulated ITC (b):												
TAPS	$ 2.2	$ 11.3	$ 6.9	$ 3.1	$ 3.0	$ 54.0	$ 249.5	$ 242.8	$ 85.8	$ 18.0	$ 36.0	$ 9.0
Field development	0.7	3.2	2.0	1.1	1.5	10.2	73.2	109.7	61.4	55.9	45.5	63.1
Total	$ 2.9	$ 14.5	$ 8.9	$ 4.2	$ 4.5	$ 64.2	$ 322.7	$ 352.5	$ 147.2	$ 73.9	$ 81.5	$ 72.1
Book ITC (c):												
TAPS	–	–	–	–	–	–	$ 49.9	$ 147.0	$ 450.4	–	–	$ 63.0
Field development	–	–	–	–	–	–	14.6	58.5	186.6	–	$101.4	63.1
Total	–	–	–	–	–	–	$ 64.5	$ 205.5	$ 637.0	–	$101.4	$126.1

(a) *This calculation assumes that 90% of TAPS expenditures and 100% of tangible outlays for field development qualify for ITC on an annual basis.*

(b) *Computed as the product of expenditures qualifying for ITC and the applicable ITC rate in a given year.*

(c) *For pre-1975 expenditures, the accumulated 1969-1974 ITC is booked in 1977 as the qualifying assets are placed into service. Beginning in 1975, the Tax Reduction Act of 1975 offered the taxpayer a choice between two methods for recognizing ITC on long-leadtime (three or more years) construction projects: (1) a progress payment treatment whereby ITC can be taken in as expenditures are made during the construction stage of a project; or (2) the historical treatment – that is, the full amount of ITC is reflected in the year the qualifying assets are taken into service. Given these alternatives, the TAPS owners have opted for the progress payment method. Under a five-year phase-in rule, book ITC in 1975 is equal to 20% of accumulated ITC for that year; for 1976, it is equal to 40% of that year's accumulated ITC plus another 20% of the previous year's amount; finally, in 1977, the remaining 60% for 1975 and 1976 is taken, as well as 100% of the 1977 amount.*

(See Appendix E on following page)

APPENDIX E

Computation of Shares Outstanding – Standard Oil Company (Ohio)

Date	Gross Production	Net Sohio Production	Shares Outstanding – Common and Common Equivalent: Special Stock	Common Stock	Total	Weighted Annual Average	BP's Equity Ownership in Sohio (Percent)
	(In thousands of b/d)		(In millions)				
July 15, 1977	300	140	8.9	29.6	38.5	–	–
September 1, 1977	600	279	8.9	29.6	38.5	–	–
October 15, 1977	600	279	13.8	29.6	43.4	–	–
November 1, 1977	1,200	559	13.8	29.6	43.4	–	–
December 1, 1977	1,200	559	15.7	29.6	45.3	–	–
December 31, 1977	1,200	559	27.9	29.6	57.5	40.9	30.2%
December 31, 1978	1,200	559	30.2	30.1(a)	60.3	60.2	51.8
December 31, 1979	1,200	559	30.2	30.1	60.3	60.3	51.8
March 1, 1980	1,400	613	30.2	30.1	60.3	–	–
April 15, 1980	1,400	613	31.5	30.1	61.6	–	–
October 1, 1980	1,600	636	31.5	30.1	61.6	–	–
December 31, 1980	1,600	636	31.5	30.1	61.6	61.2	52.6

(a) Assumes exercise of options covering 476,000 shares at prices ranging from $12.15 to $53.13 per share.

(See Appendix F on following page)

AGO 531366

Appendix F

Prudhoe Bay Field -- Kuparuk and Lisburne Formations
Derivation of Unit Producing Profits
Market of Destination -- Houston (a)

Case I: World Price

	1982		1983		1984		1985		1990	
Production Rate (millions of b/d)		0.19		0.26		0.32		0.38		0.35
Landed Crude Price		$16.80		$17.56		$18.36		$19.19		$23.94
Marine Transportation		0.80		0.82		0.85		0.87		1.01
TAPS Liability Fund		0.00		0.00		0.00		0.00		0.00
Pipeline Transportation		1.44		1.47		1.49		1.51		1.63
Valdez Netback		14.56		15.27		16.02		16.80		21.30
TAPS Tariff		3.29		3.22		3.17		3.14		4.23
Wellhead Price		11.27		12.05		12.85		13.66		17.07
Royalty @ 12.5%	1.41		1.51		1.61		1.71		2.13	
Production Taxes	0.60		0.68		0.74		0.82		0.98	
Property Taxes	1.01		1.04		1.07		1.07		1.05	
Lifting Costs	1.80		1.58		1.45		1.51		2.00	
Interest Charges	2.31		1.62		1.19		0.87		0.23	
Depr., Depl., and Amort.	2.20		3.08		3.97		4.85		4.97	
Total Costs		9.33		9.51		10.02		10.83		11.37
Pretax Profit		1.93		2.54		2.83		2.84		5.70
Income Taxes										
- State @ 9.4%	0.18		0.24		0.27		0.27		0.54	
- Federal @ 48%	0.84		1.10		1.23		1.23		2.48	
Total Income Taxes		1.02		1.34		1.50		1.50		3.02
Net Profit		$ 0.91		$ 1.20		$ 1.33		$ 1.34		$ 2.69
TAPS Profit		0.51		0.53		0.55		0.58		1.01
Integrated Profit		$ 1.42		$ 1.73		$ 1.88		$ 1.92		$ 3.70

(a) Totals may not add due to rounding.

(Appendix F continued on following page)

Appendix F (con't)

Prudhoe Bay Field -- Kuparuk and Lisburne Formations
Derivation of Unit Producing Profits
Market of Destination -- Houston (a)

Case II: Controlled Price

	1982		1983		1984		1985		1990	
Production Rate (millions of b/d)	0.19		0.26		0.32		0.38		0.35	
Landed Crude Price		$14.95		$15.70		$16.50		$17.33		$22.15
Marine Transportation		0.80		0.82		0.85		0.87		1.01
TAPS Liability Fund		0.00		0.00		0.00		0.00		0.00
Pipeline Transportation		1.44		1.47		1.49		1.51		1.63
Valdez Netback		12.71		13.41		14.16		14.95		19.51
TAPS Tariff		3.29		3.22		3.17		3.14		4.23
Wellhead Price		9.42		10.19		10.99		11.81		15.28
Royalty @ 12.5%	1.18		1.27		1.37		1.48		1.91	
Production Taxes	0.57		0.63		0.68		0.74		0.90	
Property Taxes	1.01		1.04		1.07		1.07		1.05	
Lifting Costs	1.80		1.58		1.45		1.51		2.00	
Interest Charges	2.31		1.62		1.19		0.87		0.23	
Depr., Depl., and Amort.	2.20		3.08		3.97		4.85		4.97	
Total Costs		9.07		9.23		9.72		10.52		11.07
Pretax Profit		0.35		0.96		1.27		1.29		4.21
Income Taxes										
- State @ 9.4%	0.03		0.09		0.12		0.12		0.40	
- Federal @ 48%	0.15		0.42		0.55		0.56		1.83	
Total Income Taxes		0.18		0.51		0.67		0.68		2.23
Net Profit		$ 0.16		$ 0.45		$ 0.60		$ 0.61		$ 1.99
TAPS Profit		0.51		0.53		0.55		0.58		1.01
Integrated Profit		$ 0.67		$ 0.98		$ 1.15		$ 1.19		$ 3.00

(a) Totals may not add due to rounding.

WAINWRIGHT SECURITIES INC.
Paul R. Leibman
Thomas A. Petrie

Computer Applications
Richard C. Marks

Pricing

p. 29 cites precedent for FEA to do discrim entitlements.

FEA will do 3 objectives:

1. incentive to Prudhoe max
2. regional equalization
3. flex for other U.S. prod.

no approach does all 3.

So WW does 2 cases:

1. exempt, no entitle, discrim pricing at Valdez
p. 29. 2. up. tier on W. coast landing. at W. coast in composite.

So neither read tariff.

bracket range of possibilities. 2 extremes.

AGO 531369

Major uncertainties in figuring rate of return: p1

① pricing & mktg of NS oil

② setting of tariffs

③ State taxation

TAPS tariff delay in setting.

p3 "In all likelihood resolution of ....

TAPS total cost. p.9 - Alyeska little credibility

Sale of surplus equip not incl. p.9.

ROR R

p3 — tariff will be lower than expected.

p22 — bottom - conf report — "approp method for calculating" price decision supposed to be based on ror

P35 — DCF ror = 10.6 for pipe 19.1 for field 15.7 combined assume - export of 2 mb/d, ror on equity on pipe

p36 good quote — ror

p35 "gov't main beneficiary"

p35 Indorsement quote

p37 — do oil co aggregated

AGO 531370

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER / POUCH M — JUNEAU 99811

February 10, 1977

RECEIVED
FEB 14 1977
Croft

The Honorable Chancy Croft
Alaska State Legislature
Pouch V
Juneau, Alaska 99811

Dear Senator Croft:

In addition to Dr. Mason Gaffney, the following persons who prepared parts of the Oil and Gas Leasing Study are expected to be in Juneau for presentation of the study to your committee on February 17, 1977:

Professor Richard Norgaard, U. of California, Berkeley

Professor Robert Rooney, California State, Long Beach

Professor Michael Cromlin, U. of Melbourne, Australia

Will get more details for you as I know them.

Sincerely,

Jack Roderick /ms

Jack Roderick
Deputy Commissioner

cc: Commissioner Guy Martin
Greg Erickson

AGO 531371

? for Sohio —

plan to squeeze ey live agents to field?

p. 42 - pay BP based on live profits so
want low tariff

53.155 — field
33.34% — pipe BP
} Sohio

Wainwright —
prop tax pipe valuation. 110% - ICC, state.

prob with WW - 48% fed tax
effective!!

How SOHIO diff from other industries:
① pipe ownership
② mktg opportunities.

when FEA prices tariff

AGO 531372

Probs with WW

1. assumes effectiv 48% Fed.

2. Equity or yield slightly off.

3. p 42 show unsmoothed tariffs.
AB products will smooth

?

Use ICC valuation of pipe for State prop.
p.48 - Co. high.

7. p.49 all except Amerada Hess intend tariff.

AGO 531373

47 Algebra audits by   TARIFF

① ICC

② GAO for Jackson

③ State

(48) products initial valuati on pipe won't come out till end of 78

early 1979 will issue rpt "on which a final eval of reasonableness of TAPS tariffs may ultimately be made."

49 "may be 2 years or so before final comes out."

49 Main question:

① "what is a proper rate base

② what is an appro return level . . . "

projects ① rate base valuation same

② reaffirm cost of service treatment

③ permit higher return.

Use 2 Cases

① traditional investment total.

② return on equity

③ get Wm Brothers & Ex Parte 308

AGO 531374

TAPS / TARIFF

37 State Int = max WH
Compint = max tax, low WH } due to diff in tax.

37 affects state to file case against initial tariff filings of co.

38 Wm Bros Pipeline Case - ~~equity~~ on total invest. <u>45</u>

38 predicts owners will go for 7% tariff

39. assumes ICC will use current valuation procedures.
assumes tariff based on (1) 2 m/b/day (KEL)
(2) 1.6 mb/day (no KEL)

assumes ICC will use 10% on equity.

42. "diff in ownership spawns diversity of viewpts in best way to max earnings."

p.42 SOHIO — BP agreement — net profits

47. Case I (1.6) = av 3.99 /bar Tariff 1978 = 4.23

unsmooth Case II (2.0) = av 3.55 " 1978-1990 1978 = 4.23

45 — tariff setting uncertainty

49 — final after rate case & exhibits no 308 proceeding. "TAVOT ComCarr Pipe"

46 — industry argument of incl pipe plus field together. good quote.

47 — SOHIO wants hi tariff cuz hi debt, but doesn't cuz net purchaser.

AK "concern focused on the extreme."

47.— predicts state will contest rate "most since pipe tariff dispute."

AGO 531375

Surplus: & Mktg

(p 13) amt of surplus estimate vary widely. Can't know.

(p13) Socal currently expects refiners will be largest W coast processing N. Slope

p18 !! "it is clear that"

(p14) barrel surplus even worse b/c of low quality crude.
(p.16) need de-sulph facilities due to air poll. regs.
Prudhoe makes it tougher on already hi-sulphur crudes.
adverse effect

? cites Socal & Union as being credible sources. 14, 16

19: surplus = 300,000 b/d 78
350,000 b/d 79

Socal projects 1978-1980 imports of 400,000-600 b/d of imports mostly Indonesian.

p. 18 "practicality & politics = combination of measures" ← chart of 12 solutions p 19.
projects: ① start - unsub Jones Act US Flag vessels Thru Pan. p. 18
+ small Thru 4 corners pipe & rail.
② then need subsid vessels + Jones Act waivers / exchange of NS or Calif with Japan Can. p. 21 saves costs
Canal limitation (19) = 60,000 dwt., tho some 90,000 dwt can traverse partly loaded.

p 19 - show shut-in option as "Not Applicable."

21 only small pipeline capacity available Thru 4 corners or Trans-Mt Pipe till 79.

NATURAL GAS FACT SHEET

SADELROCHIT RESERVOIR

Estimated reserves= 26 to 32 Trillion Cubic Feet (TCF)
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Estimated yearly flow = .9 Trillion Cubic Feet

Alaska's royalty share= 3.25--4 TCF
Daily royalty share = 312 Million Cubic Feet (MMCF)
Yearly royalty share = 114 BCF

*Department of Interior study.
More proven reserves are expected to be proven in the North Slope area.

ALASKAN USE

Almost all the natural gas used in Alaska is in the Cook Inlet area.

Anchorage Natural Gas uses about 30 BCF per year.
That is equal to 12 days production from Prudhoe Bay.
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Six MCF of gas is roughly equal to one barrel of oil.

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On strictly energy equivalent, $2.00 per MCF gas = $12 barrel oil.
Considering the advantages of using gas, $2.00 gas = $9 barrel oil.

United States gas production has declined from a peak of about 62 BCF per day in 1973 to 55 BCF/day in 1975.

Raising prod:

Overall discrepancies (p 8) ① W. coast surplus in 78-79
② U.S. pricing uncertainty

WW estimates new capacity to 1.6 not till late 1980 — (p.8)

(p.8) SOHIO doesn't want now as would raise ownership & hence need to take on larger TAPS so more financing. + mktg problems

(p.9) will cost 700 mill (Alyes estimates 675 m) to bring up to capacity.

(p9) by Nov 1977 will have enuf wells drilled to yield 1.2

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Compromise tax –

p2 "While little support appears to exist for the radical excess value (windfall) tax of a year ago, a consensus has apparently formed on the necessity for a major overhaul of the state's prod. tax & corp. income tax."

p.30 "fair, workable & most imp. stable tax regime"
focus tax policy on collecting "Fair share"

p31 good quote "As stated ... stable."

p32 "Hammond's objective in response some novel twist"
p32 * good quote supports ELF
bad p32 prob with ¢/barrel – Gov. ELF
bad p.32 "disincentive..." ELF
Sev.

bad p33 "alleged deficiencies" inc.
good p.33 "From AK standpt" inc
bad p.34 OCS quote inc
inc

p35 If things go well w TAPS state may not seek some taxes & ¢/Econ won't hurt. p.47 good quote on same

Legis action:
p3 "Moreover ...... rest.
p.34/35 "tariff & overcharges" long quote

35 – projections assume
① effective 9.4 90
② ELF
③ TAPS historical – not Gov. p39 – ICC uses historic replacement cost.

35 crossroads – compromise in current !!

AGO 531380

Alaska State Legislature

JUNEAU ALASKA

SENATE RESOURCES COMMITTEE - KAY POLAND, CHAIRMAN

HOUSE RESOURCES COMMITTEE - ALVIN OSTERBACK, CHAIRMAN

JOINT HEARINGS - OIL & GAS TAXATION

A G E N D A

TUESDAY, MARCH 22

BRIEFING BY RICHARD KILGORE — 9:00 A.M.
* ROOM 126, CAPITOL

BRITISH PETROLEUM — 1:30 P.M.
* COURTROOM A

WEDNESDAY, MARCH 23

F.E.A. HEARING - ANCHORAGE
FEDERAL COURTHOUSE, CONF. ROOM 284 — 9:30 A.M.

THURSDAY, MARCH 24 — GOLD ROOM - BARANOF HOTEL

COMMISSIONER GALLAGHER — 1:30 P.M.
DICK DONALDSON - SOHIO
MONTE TAYLOR - EXXON
ROGER BONEY - EXXON

FRIDAY, MARCH 25 — GOLD ROOM - BARANOF HOTEL

LARRY WILSON - UNION OIL — 9:00 A.M.

BRISTOL BAY NATIVE CORPORATION — 1:30 P.M.
OLIVER LEAVITT - ARCTIC SLOPE
MARC SINGLETARY - ATLANTIC RICHFIELD

AGO 531381

(Pricing) 26, p. 27.

(2) Set upper tier at W coast. — would this leave only crudes.
if choose this, WH will be low so will help composite &
allow upper tier price to rise.

if set at upper tier must do entitlements & way design
currently costs refiners more than crude for Calif
(reason why Calif having probs).

(3) WH = composite max
would ensure AK later doesn't rise to become disincentive to lower $.
entitlements = none a new tier (so can purchase entitlements to raise
low to composite level).

p. 29. believe FEA may opt for #2 & set entitlements
to equalize E & W.
disincentive entitlements
W purchases a portion
E exempler sells.

quotes TAPS act "benefits of such crude oil should be equitably shared, ...
by all regions of the country".

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Pricing

p. 22 cites cong rept saying decision to be based on effective rate of return.

p 22 — "much addition work remains before new Admin gives policy & rules"
[delay] p. 28 quote on can't know outcome yet.

Question - at WH or at Valdez? (p. 23)
Mortada suggests Valdez - provides incentive to devel. Lisb & Kaparuk p. 28
① gets around tariff uncertainties p. 28
p. 23 committee rpt & C.K. clearly state first-sale at WH.
Interprets 3 options for FEA:
① exempt ~~……~~ (state position) hi for short & long.
② set upper price at W. coast port low
③ set ceiling price at WH & make it = to max composite price. (hi) for now

interesting - like Tussing only exclude if greater than composite!!!

① exempt (p. 24)
a. discriminatory price based on destination (may violate antitrust) so same WH for all
all other companies prefer. LA = mkt
b. non SOHIO prefers (Houston becomes mkt so depresses all). ~~so diff WH~~ so WH = lowest value = Houston. or multiple.

In competitive mkt - non would prevail & prod. would try to sell at W. coast. But SOHIO, EXXON integration & have arranged for transport — so won't go into price war on W. coast.

(26)

26 WW - products - discrim (even tho will be moderate price war "discounting")

multiple WH has existed in Cook Inlet

AGO 531384

NATURAL GAS FACT SHEET

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Considering the advantages of using gas, $2.00 gas = $9 barrel oil.

United States gas production has declined from a peak of about 62 BCF per day in 1973 to 55 BCF/day in 1975.

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

Alaska State Legislature

Special Committee on
the Sale of
Royalty Gas

(907) 465-3873
Pouch V
Juneau, Alaska 99811

Members
Rep. Clark Gruening, Chmn.
Rep. C. V. Chatterton
Rep. Joe L. Hayes
Rep. Joseph H. McKinnon
Rep. Charles H. Parr

April 11, 1977

House of Representatives

TO: Representative Clark Gruening
FROM: Brian Rogers
RE: Wainwright Securities, Inc. Review of the Petroleum Industry: North Slope Oil and Gas

Wainwright Securities, Inc. recently compiled a comprehensive investment analysis of North Slope Oil and Gas. Their Industry Review, dated April 1, 1977, analyzes the current situation, from the investor standpoint.

Bearing in mind that the basic outlook of an investment house is different from that of the State of Alaska, opinions expressed on such matters as oil taxation by the State of Alaska may not reflect factors which should be taken into account by the State. However, the review concludes that even with the many uncertainties existing on North Slope Oil and Gas economics,

> "the uniqueness of long-lived Prudhoe Bay reserves cannot be emphasized enough in today's industry environment. With most companies facing the difficult task of replacing depleted low-cost reserves, access to substantial North Slope reserves affords the luxury of a stable underlying basic cash flow on which to launch new corporate investments for future growth." (emphasis by Wainwright).

Wainwright finds seven major observations about North Slope Oil and Gas as follows:

1. Construction Status (of TAPS): essentially on-time; 600,000 b/d starting in August, 1.2 million b/d by year-end.
2. West Coast Supply/Demand: At 1.2 million b/d, excess supply will range from 300 to 600,000 b/d. Excess will probably be shipped via Panama Canal to Houston. "The alternative of exchanging North Slope oil with Japan ... will become an option only if the surplus becomes so large that it forces a shuttng in of Prudhoe Bay production."
3. Crude Oil Pricing Policy: Price will probably range from upper tier landed West Coast price to price competitive with imported oil. Wainwright analysis suggests possible range in Long Beach in early 1978 of 11.79 to 13.90 per barrel.

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4. Alaskan Taxation:"A consensus has apparently formed on the necessity for a major overhaul of the state's production tax and corporate income tax." ..."It is somewhat premature to guage their impact on North Slope earnings." suggests perhaps the State will wait until next year because of early adjournment.
5. Pipeline Tariff Determination: Wainwright believes that there are major questions about ICC ratemaking procedures. They project a tariff in the vicinity of $4.25 per barrel in 1978 at 1.2 million b/d.
6. Production Economics: $/barrel profits to the companies range from 3.10 (Houston Delivery) to $3.59 (Puget Sound) at world price; 2.88 Houston to 3.02 Puget Sound for controlled upper tier price.
7. Company Earnings: Wainwright presents earnings expectations for each of the major reserve owners in the Prudhoe Bay field under specified price and pipeline tariff assumptions.

In their detailed analysis, they present the following statistics and arguments which are (1) new to us or (2) important data for our consideration:

1. Crude surplus on West Coast is a disincentive for expansion of pipeline capacity from 1.2 to 1.6 million b/d. (note: not Alaska tax plans). Wainwrights "best estimate" for the onstream date for the 1.6 millon b/d capacity is late 1980.
2. Wainwright believes the cost of additional capacity to be:
   to 1.6 million b/d: $700 million
   ? to 2.0 million b/d: $855 million estimate for expansion from 1.2 to 2.0 is "probably too low".
3. Wainwright examined a number of West Coast supply/demand analyses which show more optimistic assesments of West Coast production from (1) production from Elk Hills (2) improved economics for enhanced recovery projects and (3) renewed offshore development activities. The nature of the problem is "anything but deterministic." Socal will have the ability to be the largest West Coast processor. Wainwright examined various possibilities for treatment of the surplus problem (see pp. 18 - 20).
4. Wainwright explored the alternatives available on FEA pricing of North Slope oil. They suggest that discriminatory pricing, with the possibility of moderate discounting, is a likely situation, as has existed at Cook Inlet for a number of years.
5. On the matter of Alaskan taxation, Wainwright asks if compromise will replace the confrontation which existed last year. A full reading of pp 30 - 36 would be advisable. Wainwright

notes two "novel twists" in the Alaskan taxation picture: the E.L.F. concept and the franchise tax. They suggest that ELF has some positive structural features, but creates a disincentive for development of Kuparuk and Lisburne. "From Alaska's standpoint, passage of the franchise tax would undoubtedly resolve some glaring deficiencies in its current income tax treatment. Also, it would ensure that the North Slope producers pay something resembling the 9.4% nominal tax rate imposed on domestic (Alaskan) corporations doing business only in the state - versus the 2%-3% rate that otherwise would apply to a multinational oil company." Wainwright asserts that encompassing OCS production and oil tankers exceeds the limits of fairness and reasonableness. They see a key objective for Alaska as being the expansion of permanent fund revenue as well as closing of existing loopholes.

Wainwright says that legislative consideration is unsure, "with a drastically altered leadership and committee set-up in the Senate", and that the state "will probably be concerned primarily with the timing and mechanics of how best (not whether) to obtain a portion of the economic rents it believes exists at Prudhoe Bay." Wainwright believes the uncertainties of pricing may delay consideration, adding "Certainly, a delaying action would likely be in the best interest of the oil companies."

6. Wainwright asserts Real DCF rates of return on Prudhoe Bay production of 19.1 %, on the pipeline of 10.6%, and a 15.7 % composite rate. They make predictable noise about theneed for the state to compromise on taxation "to go a long way towards establishing a tax structure conducive to a healthy investment climate for the oil industry in Alaska."
7. Wainwright discusses tariff possibilities in light of the Williams Brothers Pipe Line Company (WBPL) rate case a and how it pertains to the proper rate of return on the rate base. (meaning possible 7 % rate of return on equity, instead of 7 % on total investment). They predict that Prudhoe Oil Pool field development will result in a tariff ranging between \$3.54 and \$5.14 per barrel. With the inclusion of Kuparuk and Lisburne, the tariff ranges from \$3.14 to \$4.28 per barrel.
8. Wainwright says the tariff uncertainties are the largest currently in the picture, due to the inportance of the level of TAPS tariff in the overall economics of North Slope oil.
9. Wainwright make s a number of estimates of profitability of the Prudhoe Bay field, depending on a number of factors: market destination, production level, crude oil price, marien transporation, 12½ % royalty, PRODUCTION TAXES BASED ON E.L.F., property taxes, STATE INCOME TAX AT 9.4%, and federal income tax at 48%.

10. Wainwright briefly examines North Slope natural gas issues, noting the "number of uncertainties tat seriously hamper a comprehensive assessment of the economics of exploiting this resource."
11. Detailed forecasts of company earnings are made on pp. 64 - 66.
12. Wainwright notes that unit profitability for Kuparuk and lisburne will be far lower than for the main field, but "development of these currently marginal reserves, by increasing pipeline throughput, will enhance the economics of other North Slope production."

K. E. SHOWALTER: The following is a phone conversation between K. E. Showalter of Sohio, and Mr. Paul Leibman, Wainwright Securities, Inc. in New York. The call was made on April 14, 1977 to clarify the rate of return numbers as contained in the report versus those arrived at by the Alaska State Department of Revenue. Other points of contention in the report were also explored.

SHOWALTER: Mr. Leibman, the Alaska Department of Revenue offered testimony this morning to the House Finance Committee that characterized your reported 19.1% rate of return on Prudhoe Bay as incorrect, and stated that the real rate of return is 25.4%, and they used your cash flow numbers. Can you tell me how such a difference could occur?

LEIBMAN: Well, in the first instance, they have taken a cash flow series that reflects escalation from both Prudhoe price and operating costs over the life of the field. And looking at a real rate of return on a project, you then have to perform one additional calculation which involves going through and deflating the entire series back to a current year. In this case, 1977. So for expenditures that occurred prior to 1977, the cash flow numbers that we show would be increased, and for those that occur after 1977, both inflows and outflows, they would be deflated or reduced. So in the end you come up with an adjusted cash flow series which is then put into a computer program, which is how we derived the 19.1%. The difference can be characterized as a real return versus a nominal return. In one case inflation is included in the calculation, in the other it is excluded.

SHOWALTER: A further question on that same point, Mr. Leibman, how would an investor look at this? By which method would an investor typically calculate the rate of return?

LEIBMAN: Because so many assumptions are necessitated, as far as looking at inflation in future years, it is our impression that most companies approaching a major new project would tend to base their calculated threshold return on a real rate of return, excluding any influence of inflation.

SHOWALTER: In other words, they would do it by the method that you used in your study?

LEIBMAN: Yes.

SHOWALTER: A further question -- In your report you show calculated returns using a 9.4% direct accounting income tax and the new economic limit factor severance tax. Why did you do this since these are not current law?

LEIBMAN: There are really two reasons why I think we adopted that approach. On the one hand are analyses already included: two cases for crude oil prices, two cases for the final determination of pipeline tariffs. To go one step further and to have two additional cases for taxes, both the current situation and the proposals as outlined by the Hammond Administration, would result in so many different earning cases for the companies, that would not really be relevant in terms of presenting something to investors they could really understand. Given that we feel the crude oil pricing question and the pipeline tariffs issue are probably more important in an absolute sense, we have decided to use only one guess as far as how we think the legislation might come out.

The second point is, to the extent that we are dealing here with equities or common stock, most investors, I think, are more sensitive to determining what could be called a "worse case" possibility. They want to see what the fundamental position of the companies would be to the extent that the worse possible solution occurs. That is probably the most conservative way of approaching investment. From that standpoint we, once again, try to make our best guess as to how the current proposals would finally emerge from the legislature. We've tried to be conservative in developing our earnings estimates, feeling that if some change occurred in the future we would not have to go back and recalculate our numbers, which can cause much disharmony in the stock market.

SHOWALTER: Are you, then, endorsing increased taxes in Alaska?

LEIBMAN: It is fair to say that while there are probably some legitimate problems with the current tax structure of the State of Alaska, as affects the petroleum industry, we feel that, on balance, that their current arrangement appears more than adequate, given the State's fiscal outlook, and what appears to us to be an absence of what many people are considering to be economic rents of the Prudhoe Bay field. The companies at Prudhoe Bay are earning what by most measures would be a below average rate of return -- when you consider that this is the largest oil field ever found in North America. And that the cash flow from Prudhoe Bay has to cover the dry holes that are being drilled in many other parts of the United States and abroad. We have a hard time reconciling the desire for increased taxation with what appears to already be a return on investment situation which is, in many respects, marginal.

SHOWALTER: In one section of your report you mentioned some particularly contentious provisions in the tax proposals now before the legislature. Could you tell us what those are?

LEIBMAN: I think the points that bother us the most break down in three ways. First of all, the concept of a floor price underneath the production tax proposal. This in effect would allow the State to determine its severance tax on the basis of a deemed market price for the oil landed on the West Coast. The problem here is, to the extent the federal government requires a price for Alaskan oil that is below the market price for foreign oil landed on the West Coast, this would tend to squeeze the companies margins fairly severely. In effect, they would be caught between the State of Alaska's desire to maintain their revenue flow and the federal government's desire to set a price for political and other factors. We think the State is, in effect, weakening their case for a well price by, in effect, trying to protect itself in any event.

A second point would be extending the concept of the franchise tax to include such facilities as LNG, plants, refineries, petrochemical plants.

We think, thirdly, offshore oil and gas. That trying to derive taxes from OCS production appears to be far beyond what the State feels is their need to redress and legitimate questions in their current tax structure.

And finally, the concept of an economic value for the pipeline, in terms of property tax determination, appears to us to be motivated more by desire to increase revenue than to look at the historical situation of pipelines, in terms of their economic situation and how taxation should be applied to them. The basic rationale here is that historic cost has been the traditional way that pipelines have been valued, and the State is now talking of a replacement cost-type concept which we find hard to accept.