

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
448 SCOMM12: OIL & GAS TAXATION & PIPELINE 1972-77

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 will 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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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.

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.

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

*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

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 produced)*

- (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 7/bbl*

*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.

- (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.

25.5 scums
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 draw-down 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

*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 Borough's authority to enact the new levy and the extent to which it may be credited against the state property tax.

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
Sohio/BP	53.2% 53.155
Arco	20.5 20.273
Exxon	20.5 20.273
Mobil	2.1
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 Profile
Market of Destination -- I.A./Long Beach (a)
Case 1: World Price

Production Rate (millions of b/d)	1978	1979	1980	1985	1990
	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	3.28	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	0.52
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	5.21
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	3.37	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%	1.26	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.

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.*

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

*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.).

April 1, 1977

WAINWRIGHT SECURITIES INC.

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	1977 (post-Labor Day)		Northern Tier/Chicago	Totals
				L.A./Long Beach	Houston Tanker Pipeline		
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	—	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

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, tying 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

MAP II



LEGEND

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

77 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

**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.*

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.

ASG 5475
 *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.

T
no Arctic Gas

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 @ 12 1/2%	9.38		12.50
Severance tax @ 10%	6.56		8.75
DD&A and lifting costs	<u>17.57</u>	<u>17.57</u>	
Total costs		<u>33.51</u>	<u>38.82</u>
Pretax income		41.49	61.18
Income taxes @ 52.9%		<u>21.95</u>	<u>32.36</u>
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% 42.12%
Exxon	8,100	33.9 42.12%
Mobil	230	1.0
Phillips	230	1.0
Standard Oil (Ohio)	7,100	29.7 14.81%
Other (a)	<u>140</u>	<u>0.5</u>
	23,900	100.0%

(a) Includes Socal and the PLAGM group.

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

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.

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

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)

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		Capital Expenditures	Borrowings	Repayments	Net Cash Flow (c)
				State	Federal (b)				
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	2,749	414	78	181	839			368	1,236
1995	2,820	435	72	194	909			368	1,211
1996	2,894	457	67	205	977			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)

APPENDIX B
(Continued)

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

	Oil Revenues	Lifting Costs	Royalty	Production Taxes	Property Taxes	Income Taxes		Capital and Exploratory Expenditures	Borrowings	Repayments	Net Cash Flow (c)		
						State	Federal (b)				Oil	Natural Gas (d)	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
1985	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	Lifting	Royalty	Production	Property	Income Taxes		Capital and	Borrowings	Repayments	Net Cash Flow (c)		
	Revenues	Costs		Taxes	Taxes	State	Federal (b)	Expenditures			Oil	Natural Gas (d)	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	\$10,739	\$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

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

Case 1: World Price

	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>
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	0.36	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	1.12
Total Costs	2.94	3.12	3.37	4.85	5.25
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	0.41	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 (Sadlerochitto) Reservoir
Derivation of Unit Producing Profits
Market of Destination -- Puget Sound (a)
Case 11: 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	3.76	5.14
Wellhead Price	7.40	8.32	9.50	13.07	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.	0.15	0.40	0.46	1.12	1.12
Total Costs	2.72	2.94	3.10	4.56	5.49
Pretax Profit	4.68	5.38	6.40	8.51	10.91
Income Taxes					
- State @ 9.4%	0.44	0.51	0.60	0.80	1.03
- Federal @ 48%	2.03	2.56	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)

Frudhoe 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	0.03	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%					
Production Taxes	1.11	1.18	1.35	1.79	2.18
Property Taxes	0.75	0.78	0.89	1.16	1.30
Lifting Costs	0.14	0.16	0.16	0.30	0.38
Interest Charges	0.34	0.36	0.32	0.41	0.62
Depr., Depl., and Amort.	0.22	0.20	0.14	0.03	0.03
Total Costs	0.35	0.40	0.46	1.12	1.19
Pretax Profit	2.91	3.08	3.33	4.81	5.30
Income Taxes	5.99	6.37	7.46	9.49	11.73
- State @ 9.4%					
- Federal @ 48%					
Total Income Taxes	0.56	0.60	0.70	0.89	1.10
Net Profit	2.60	2.77	3.24	4.13	5.10
TAPS Profit	3.17	3.37	3.94	5.02	6.20
Integrated Profit	\$ 2.82	\$ 3.00	\$ 3.51	\$ 4.47	\$ 5.53
	0.56	0.60	0.43	0.72	1.25
	\$ 3.38	\$ 3.60	\$ 3.94	\$ 5.19	\$ 6.78

(a) Totals may not add due to rounding.

Appendix C (cont.)

Prudhoe Bay Field -- Main (Gadecochile) Reservoir
 Calculation of Unit Producing Profit
 History of Production -- 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 No-back	11.33	12.28	12.76	16.45	21.11
TAPS Tariff	4.23	4.28	3.58	3.74	5.16
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	0.41	0.48	0.58	0.77	0.99
- State @ 9.4%	1.92	2.22	2.66	3.58	4.59
- Federal @ 48%	2.33	2.70	3.24	4.35	5.58
Total Income Taxes	0.56	0.60	0.43	0.72	1.25
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 -- Unit (Sadlerochit) Reservoir
 Derivation of Unit Producing Profits
 Market of Destination -- Houston (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	\$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	0.07	0.03
Depr., Depl., and Amort.	0.35	0.40	0.46	1.14	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

	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>
Production Rate (millions of b/d)	1.20	1.20	1.42	1.60	1.27
Landed Crude Price	\$12.19	\$13.17	\$17.67	\$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	3.38	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	3.03	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 (cont)

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

Puduhoe 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	\$12.17	\$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 Retback	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
Pre-tax 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	<u>\$55.0</u>	<u>\$262.0</u>	<u>\$160.0</u>	<u>\$72.0</u>	<u>\$74.0</u>	<u>\$1,014.0</u>	<u>\$3,553.0</u>	<u>\$3,913.0</u>	<u>\$1,752.2</u>	<u>\$744.5</u>	<u>\$949.4</u>	<u>\$848.0</u>
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	<u>\$41.5</u>	<u>\$208.0</u>	<u>\$126.1</u>	<u>\$59.1</u>	<u>\$63.3</u>	<u>\$ 916.3</u>	<u>\$3,226.8</u>	<u>\$3,525.2</u>	<u>\$1,471.6</u>	<u>\$739.4</u>	<u>\$814.9</u>	<u>\$721.0</u>
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	<u>\$ 2.9</u>	<u>\$ 14.5</u>	<u>\$ 8.9</u>	<u>\$ 4.2</u>	<u>\$ 4.5</u>	<u>\$ 64.2</u>	<u>\$ 322.7</u>	<u>\$ 352.5</u>	<u>\$ 147.2</u>	<u>\$ 73.9</u>	<u>\$ 81.5</u>	<u>\$ 72.1</u>
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	--	--	--	--	--	--	<u>\$ 64.5</u>	<u>\$ 205.5</u>	<u>\$ 637.0</u>	--	<u>\$101.4</u>	<u>\$126.1</u>

- (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)

PETROLEUM INDUSTRY

APPENDIX E

Computation of Shares Outstanding — Standard Oil Company (Ohio)

Date	Gross Production (In thousands of b/d)	Net Sohio Production	Shares Outstanding — Common and Common Equivalent			Weighted Annual Average	BP's Equity Ownership in Sohio (Percent)
			Special Stock	Common Stock	Total (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)

Appendix F

Prudhoe Bay Field -- Kuparuk and Lisburne Formations
Derivation of Unit Producing Profiles
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 Wetback	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)

April 1, 1977

Appendix F (con't)

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

Case 11: 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 Berback	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

PETROLEUM INDUSTRY

Prin

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

FEA will do 3 objectives:

- ① incentives to produce more
- ② regional equilibrium
- ③ flex for other U.S. prod.

No approach does all 3.

So WW does 2 cases:

- ① exempt, no entitlement, discriminating at Valley
- p. 29. ② up. tier on W. coast landy. at W. coast
in composite.

↗ So really need tariff.
bracket range of possibilities. 2 extremes.

Major uncertainties in figuring rate of return: p1

- ① pricing & mktg of US oil
- ② setting of tariffs
- ③ State taxation

TAPS tariff delay in setting.

p3 "In all likelihood resolution of

TAPS total cost. p.9 - Mystra little credibility
Sale of surplus equip not incl. p.9.

ROR R

p3 - tariff will be lower than expected.

p22 - both - conf report - "approx method for calculating"
pau deun supposed to be based on ROR

p35 - DCF ROR = 10.6 for pipe 19.1 in field 15.7 combined
assume - expense of 2 m b/d, ROR on equity on pipe

p35 good guess - ROR

p35 "good main benchmarking"

p35 Indonesia quote

p37 - do oil co agree point

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

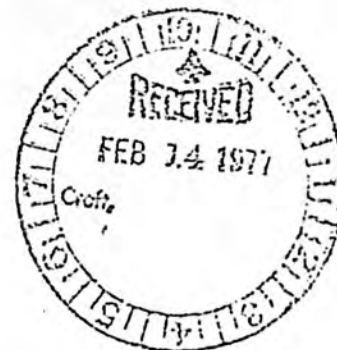
JAY S. HAMMOND, GOVERNOR

OFFICE OF THE COMMISSIONER

POUCH M - JUNEAU 99811

February 10, 1977

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 *-check name*

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 Sothe -

plan to squeeze up line agents to field?

p. 42 - pay BP band on line projects so
want low tariff

53.155 - field } Sothe
33.3470 - pipe
BP

Wainwright -

prop tax pipe valuation. 110% - KC, state.

prob with WU - 48% fed tax
effective!!

How SOHIO diff from other industries:

- ① pipe ownership.
- ② mktg opportunities.

when FEA price
tamp

Proto with wlv

1. Assumes effective 48% Fed.
2. Equity on field slightly off.
3. p 42 show unsmoothed profits.
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.

47 Algebra audit by

TAR/FF

- ① ICC
- ② GAO for Jackson
- ③ State

④ products initial value ^{on pipe} won't come out till end of 78
early 1979 will issue report "on which a final eval of
reasonableness of TAPS tariffs may well emerge; or not."

49 "may be 2 years or so before final comments."

49 Main question:

- ① "what is a proper rate base
- ② what is an appropriate level"

projects ① rate base robustness
② reappraisal 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

TAPS / TARIFF

37 state int = max w/H } due to diff
 Comp int = max tax, low w/H } in tax.

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

38 Wm Bros Apulini Case - ~~applies~~ on total invest. 45

38 predicts owners will go for 7% tariff

39. assumes ICC will use current valuating procedures.
 assumes tariff based on ① 2 m/b/day (K&L)

② 1.6 m/b/day (no K&L)

Assumes ICC will use 10% on equity.

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

p. 42 SOHIO - BP agreement - int profits

42. Case I (1.6) = av 3.99 / base Tariff 1978 = 4.23

UNsmooth Case II (2.0) = av 3.55 1978-1990

45 - tariff setting uncertainty

49 - final after rate case exists no 308 proceeding. "Invot
 Com Carr
 Pipe"

46 - industry argument of incl pipe plus field
 together. good goods.

47 - SOHIO wants hi tariff cny hi debt, but
 doesn't cny net purchaser.

AK "concern based on its claim"

47. - predicts state will contest rate "most s/o pipe tariff
 dispute."

AGO 531375

Surplus & Mktg

P13 Ant of surplus estimate range widely. Can't know.

P13 Social currency, rapidly repairs will be largest
W coast processing N. South.

P18 !!
" it is clear that

P14 barrel surplus even worse use of low quality crude.

P16 need de-sulph facilities due to air poll. reg.

Prudhoe makes it tougher on already hi-sulphur crudes.

Adverse effect

? cites Social & Union as being credible sources. 14, 14

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

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

P18 "practicality & problem = combination of measures" ← dist of 12 solutions
P19.

projects: ① Start - unsat Jones Act US Flag vessels thru Pan. P18

+ small thru 4 corners pipe & rail.

② then need subsid vessels of N's or Calif with Japan Can. P21
+ some Act waivers saves costs

Challenger (14) = 60,000 dwt, to some 90,000 dwt can traverse partly route.

P15 show shutrin option as "Not Applicable."

2) only small pipeline capacity available thru 4 corners a Trans-Mt Goya till 79.

NATURAL GAS FACT SHEET

SADELROCHIT RESERVOIR

Estimated reserves= 26 to 32 Trillion Cubic Feet (TCF)
Estimated daily flow from pipeline= 2.5 Billion Cubic Feet* (BCF)
Estimated yearly flow = .9 Trillion Cubic Feet

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

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

ALASKAN USE

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

Anchorage Natural Gas uses about 30 BCF per year.
That is equal to 12 days production from Prudhoe Bay.
On a cold day in Anchorage, about 120 MMCF is used.
Anchorage Natural Gas has firm commitments for 10--15 years of gas from Cook Inlet.

Phillips Petroleum uses about 61 BCF per year, most of which is liquified and shipped to Japan.

Collier Chemical Corporation uses about 21 BCF per year in their Ammonia/Urea plant. They are now doubling their operation.

One thousand cubic feet of gas (1 MCF) is equal to about 1 Million BTU. North Slope gas is particularly "rich" at about 1.1 MMBTU.

Six MCF of gas is roughly equal to one barrel of oil.

Consumers are willing to pay a premium for gas. It is a clean energy source.

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

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

Raising prod.

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

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

(p.8) SONIO doesn't want Norway would raise ownership & have need to take on larger TAPS so more financing. + mktg problems

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

(p.9) by Nov 1977 will have enough 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 mod. tax & corp. income tax."

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

p31 good quote "as stated ... stable."

p32 "Hammonds' objectives incorporate some real thrust"

p32 * good quote supports ELF

bad p32 prob with & / barrel - Can. ELF } Sev.

bad p.32 "discretion..." ELF

bad p33 "alleged deficiencies" inc.

good p.33 "From AK standpoint" inc } inc

bad p.34 OCS quote inc

p35 if things go well w TAPS state may not seek more taxes
& & / from windfall. p.47 good quote on same T

Legislation:

p3 "Moreover ... rest."

p.34/35 "Timing & mechanics" long quote

35- properties assume

① effective 9.4 90

② ELF

③ TAPS historical - not Gov. p39 - TCC uses historic replacement cost.

35 crossroads compromise in current !!



JUNEAU ALASKA

Alaska State Legislature

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

Pring

26,
p. 27.

② Set upper tier at W coast. — would this have any drawbacks.
if choose this, WH will be low so will help composite &
allows upper tier price to rise.

if set at upper tier must do entitlements & way designed
currently costs up to more than input for Calif
(reason why Calif having probs).

③ WH = composite max

would ensure AK later doesn't rise to become disinclined to lower it.
entitlements = none a new tier (so an purchase entitlements to raise
low to composite level).

p. 29. believe FEA may opt for #2 & set entitlements
to equalize E & W.

discriminate entitlements

W purchases a partial
E supplies sells.

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

NATURAL GAS FACT SHEET

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Pricing

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

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

Question — at WH or at Valley?

(p. 23)

Mortada suggests Valley — provided ^{present to devel} ^{gets around tariff} ^{discrepancies} ^{p. 28}

p. 23 committee rpt & C.R. clearly state first-sale at WH.

Interprets 3 options for FEA:

- ① exempt ~~as state power~~ (state power) hi for short & long.
- ② set upper price at W. coast port low
- ③ set price at WH & max it = to max competitive price. (hi) for now

intensity — like Tossing only exclude if greater than competitive !!!

①

exempt

(p. 24)

a. discriminatory ^{price} based on destination (may violate antitrust) all other compare prefer. LA = mkt so same WH for all

b. non SOHIO prefer (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 & others have arranged for transport — so won't go into price war on W. coast.

(26)

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

multiple WH has existed in Cook Inlet

NATURAL GAS FACT SHEET

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Phillips Petroleum uses about 61 BCF per year, most of which is liquified and shipped to Japan.

Collier Chemical Corporation uses about 21 BCF per year in their Ammonia/Urea plant. They are now doubling their operation.

One thousand cubic feet of gas (1 MCF) is equal to about 1 Million BTU. North Slope gas is particularly "rich" at about 1.1 MMBTU.

Six MCF of gas is roughly equal to one barrel of oil.

Consumers are willing to pay a premium for gas. It is a clean energy source.

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

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

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Alaska State Legislature

SPECIAL COMMITTEE ON
THE SALE OF
ROYALTY GAS

(907) 465-3073

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JUNEAU, ALASKA 99811



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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 shutting 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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Representative Clark Gruening
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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 gauge 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 million 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 assessments 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 the need 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 importance of the level of TAPS tariff in the overall economics of North Slope oil.
9. Wainwright makes a number of estimates of profitability of the Prudhoe Bay field, depending on a number of factors: market destination, production level, crude oil price, marine transportation, 12½ % royalty, PRODUCTION TAXES BASED ON E.L.F., property taxes, STATE INCOME TAX AT 9.4%, and federal income tax at 48%.

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10. Wainwright briefly examines North Slope natural gas issues, noting the "number of uncertainties that 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.

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Finance Committee Chairman's Report on HCS CS SB 238, the Oil and Gas Properties Production Tax

PART I. SUMMARY OF TESTIMONY

Hearings were held from April 12 to April 14 by the House Finance Committee to take testimony on bills dealing with state taxation of the oil industry. Testimony was presented by consultants for the committee, representatives of the state Department of Revenue, the oil industry and by other individuals.

The first witness, Mr. Niall Trimble, Principal Economist for the Alaska Department of Community and Regional Affairs, testified that Alaska continues to be a most attractive prospect for oil development. Alaska still offers the oil industry high profits, low taxation relative to other areas of the world, outstanding geological prospects, and security of supply.

Mr. Trimble concluded that the oil industry will remain and continue to expand its activities in Alaska whether or not the modest tax increase proposed by the administration is adopted.

Professor Jerome Zeifman, Professor of Law at the University of Santa Clara and formerly Senior Counsel to the United States House Judiciary Committee, specializing in state-federal tax relations, testified that current state tax policy (i.e. the multi-state tax compact), with its use of federal taxable income, substantially erodes the State's tax base. He observed that changes in state and local taxation have never caused companies to change the location of their exploration and development efforts. In response to industry arguments that no tax increases ought to be considered when state budget surpluses are anticipated, Mr. Zeifman reminded the committee of the Biblical injunction to store grain in the seven fat years to avoid famine in the seven lean years.

Professor Edward Shaffer of the Department of Economics at the University of Alberta pointed out that oil will provide Alaska's major source of capital for the next several decades. This capital can be turned into human capital by way of education and health, or into direct business capital, which provides a stream of employment and income for a rising standard of living for Alaska's residents.

Adequate transformation of capital can only take place, Dr. Shaffer noted, by effective state government tax policy and, in part, by the use of the Alaska Permanent Fund. An increase in state tax revenues from the oil industry was necessary, in his view, to sufficiently finance the diversification of the Alaska economy, since the oil industry would otherwise use a substantial part of

its profits for investment in other parts of the world. Diversification of Alaska's economy could take place through long-term loans from the Alaska Permanent Fund, or through capital budgets for transportation, communication, and the like.

Professor Schaffer pointed to the experience of oil production in Alberta and Nigeria and copper mining in Zambia and Chile, where these industries have not, in-and-of themselves, fostered economic diversification. Dr. Schaffer believes that local processing, business expansion or new businesses spurred by the oil industry in Alaska would likewise not be large-scale, and will decline as oil production declines.

Mr. Joseph Kemp, a noted specialist in the field of oil taxation, and Senior Lecturer in Economics at the University of Aberdeen, Scotland, commented on the many parallels between oil development in Scotland and in Alaska. He noted that the discoveries near Scotland came in the late 1960's, after payment of relatively modest lease fees for exploration rights. Following the fourfold rise in oil prices in 1973, North Sea oil fields were, like the Prudhoe field, suddenly capable of large returns (up to 50% on a discounted cash flow basis.)

- Mr. Kemp explained that much of these windfall profits were surplus to amounts needed by the companies to develop the North Sea fields and to search for additional fields. Despite tax raises in 1975 of 60 to 70 percent of total profits, there was no slowing of oil industry activity in the North Sea. -

Mr. Kemp described the unusual action taken by the people of the Shetland Islands, who secured compensation from the oil industry to provide for the social and economic disruption caused by oil development activities. This compensation, he said, is being used to rebuild and diversify local industries and to pay the costs of providing additional public facilities, a function possibly similar to that of the Alaska Permanent Fund.

The Department of Revenue offered data gathered from the tax commissioners of eight states which show that Alaska ranks fourth among the states in total oil and gas taxation.

Alaska would rank second, following Louisiana, if the tax measures proposed by the Administration are passed.

Moreover, the proposed tax increases will not, according to the administration, have a major impact upon the rate of profitability. Using the assumptions and data of the report by Wainwright Securities, the changes reduced discounted cash flow returns on the field by less than 1% (in nominal terms).

The Administration strongly urged raising the wellhead value at which the cents-per-barrel severance tax goes into effect (from the present \$6.33 to \$7.50). In addition, the Administration recommended that the wellhead value floor (at which the cents-per-barrel tax would go into effect) should rise with inflation relative to the Gross National Product deflator (instead of the Wholesale Price Index, which for some years has been going up more rapidly than the cost of living). These provisions would

give the State an "insurance policy" against Federal or corporate manipulations of wellhead values and would help protect the State's revenues.

Numerous witnesses from the oil companies appeared before the committee and there was a certain amount of repetition in this testimony. The following is a summary of each of the arguments directed against the bills:

Several of the companies pointed out that the State of Alaska had signed contracts with them in 1964, 1966 and 1969 to lease the land at Prudhoe Bay. They felt that the state was trying to "change the rules of the game" by the unfair use of the state's taxing power.

Even though taxation increases will probably not affect industry willingness to remain at Prudhoe Bay, it could reduce the incentives for further oil exploration and development, the witness said.

Oil company witnesses stressed the need for tax rates in Alaska to stay in line with other states, and since they alleged that tax rates on oil in Alaska were already the highest in America no further increases should be allowed.

Oil company witnesses, while avowing the readiness of the industry to pay its share of taxation actually required by the state, expressed reluctance to pay higher taxes when the Department of Revenue was predicting budgetary surpluses.

Producers in the Kenai-Cook Inlet area warned that higher taxes would compound the problems they face as a result of Federal price controls and the greater costs in the later stages of field recovery.

Most of the testimony from oil company witnesses was largely philosophical in nature, without specific attacks on the provisions of the bills before the committee or the research reports that lay behind them. However, the testimony from one company-Exxon-differed sharply from the others. Exxon submitted to the committee its own economic analysis of the profitability of the Prudhoe Bay field. This study was the first detailed industry comment on the profitability report prepared for the Legislature by consultant Dr. Michael Tanzer over 15 months ago.

A number of errors of fact in the Exxon testimony are already apparent:

1. In questioning the accuracy of the probable rate of profitability of the Prudhoe Bay Field established by the Tanzer reports, Exxon witness Monte Taylor stated that no allowance was made for payment of reserves tax by the companies. Payment of reserves tax was in fact included in the calculations presented on pages 42-43, 49 and 94 of Tanzer's first report to the Legislature.

2. Mr. Taylor also stated that Tanzer did not deal with payments in respect to property tax. In fact, Tanzer covered this on pages 44, 47 and 49 of the first report.

3. Mr. Taylor also criticized the Tanzer report for not including \$900 million in bonus bids paid in the 1969 lease sale. He neglected to mention that 90% of these payments were for areas outside the boundaries of the oilfield under consideration. These payments were not made by the principal leaseholders in Prudhoe Bay.

4. The Exxon study asserted that the return on the field and the pipeline should be considered together. However, since pipeline tariffs have first claim on any return from Prudhoe Bay, it is clear that the risks involved on the two investments are of different orders of magnitude. These differences are reflected in the willingness of banks to finance 85-90% of the pipeline costs, compared with only 45-55% of field development costs. Dr. Milton Lipton of Walter Levy & Associates and Dr. Walter Mead of the University of California both concur in the validity of treating the pipeline as a separate profit center.

Likewise, Messrs. Lipton and Mead agreed that Exxon's inclusion of \$1.8 billion for construction of new tankers in the capital cost of field development is improper.

Mr. Taylor contrasted the DCF rate of return produced by Exxon (18%) with that contained in the latest report from Tanzer (29%). He did not inform the committee that Exxon's figure was a constant dollar rate of return, which took out the effects of inflation. If it were done on the same basis as Tanzer's, the Exxon rate would be around 25%.

The Exxon representative attacked Dr. Tanzer's approach in excluding the cost of the pipeline from field investment, describing it as "faulty economic analysis, ... naive and illogical" and "completely unrealistic". Mr. Taylor admitted that he did not know of any independent, published economist who agreed with his views, and "had not tried to find one."

One individual witness, Mr. Eben Hobson, Mayor of the North Slope Borough, focused on the need for the industry to become "good corporate citizens" and to pay the taxes they can well afford to bear. Mr. Roger Lang, appearing for the Bristol Bay Native Corporation, expressed fears that some Native regional corporations might be adversely impacted in their search for, and development of, medium and marginal prospects under their lands.

Mr. Duane Carlson testifying for the AFL-CIO, Alaska, advanced the view that oil taxes in other states were "their own business" and that Alaska's goal must be a consensus on the "price we want for our resources". Until that occurs, he said, the industry had a legitimate complaint about unstable tax policy in Alaska. However, he said the price Alaska chooses to set should not depend on whether or not Alaska has predicted budgetary surpluses.

Mr. Vic Fisher, a senior member of the Institute of Social and Economic Research, University of Alaska, set out a "one-time" theory of taxation, arguing that oil, primarily Prudhoe Bay, is the only known source of large revenues for Alaska for decades to come. He challenged industry claims that such revenues are "surplus" to Alaska's real needs, noting the great cost of needed capital improvements in most of rural Alaska, using the North Slope Borough's plans as an example.

PART II. NEW INFORMATION

The new facts that emerged from the House Finance hearings include:

- Handwritten note:* *Higher oil countries first allow industry to recover costs, then either nationalize or tax.* →
- a) Industry acknowledgement that Alaska's taxation on oil is much lower than that found in the vast majority of oil producing areas in the world.
- b) According to the administration's calculations, based on information from tax commissioners of eight oil producing states, Alaska does not have the highest oil taxes in the U.S. Alaska now ranks fourth and will, after the passage of these bills, rank second.
- c) The discounted cash flow (DCF) analysis of returns appears to be the main technique used by the oil companies in estimating the profitability of an oil field.
- d) The risks for the pipeline are in a lower category than for the field itself and that returns on the pipeline investment are limited by U.S. law to 7%.
- Handwritten note:* *using Wainwright data* ←
- e) The Administration and Drexel-Burnham studies of DCF returns on Prudhoe Bay were 26% and 27% (at today's dollars and setting aside pipeline and tanker investment). Both studies used medium estimates for oil production and both made the conservative assumption that the companies will pay an effective 48% Federal income tax rate. Several companies admitted, however, that they paid far less than the full Federal rate.
- Handwritten note:* *using nominal dollars later disclaimed by Revenue.* ←
- f) The Administration offered data showing that the proposed taxes would lower DCF returns on Prudhoe Bay by less than 1%. Witnesses appearing in behalf of the oil companies conceded this point.
- Handwritten note:* *1/4 DCF*
- Handwritten note:* *11 - 25*
- g) BP and SOHIO stated that passage of the tax bills would make no difference to their future operations. They will continue their investment in Prudhoe Bay and will continue their exploration program in Alaska.

PART III. CONCLUSIONS

The industry spoke of the "unfairness" of changing the tax rules after they had made substantial investments in Prudhoe Bay. Since 1973, though, the price of oil has more than quadrupled, dramatically increasing the value of this field without any effort on the part of the companies. While inflation and environmental constraints have pushed up total costs, total profits have risen even further. There must be a balance of the "loss" of profits which the companies could not, and did not, expect against the responsibility to protect the long-run interests of Alaskans.

Certainly the oil companies would have been expected to come to the state if the costs of the pipeline or mistaken estimates of recoverable reserves had trapped them under the previous, depressed prices. No contract prevents the industry from asking for, and receiving, lower

*As only royalties
severance can
be decreased on a well-by-well basis.*

severance and other taxes. Dr. Shaffer reported that companies in Alberta broke a joint venture agreement with the province for extracting oil from tar sands (the Syncrude project) until new terms were obtained, including higher government aid.

No oil company has ever had an agreement with the state of Alaska that taxes would not be raised in the future. To the contrary, the oil companies holding the major leases on the North Slope fully expected that taxes would in fact be raised even before the oil flowed.

The industry emphasized that higher taxation could discourage further oil activity in the state. They did not, however, explain why this might occur when Alaska does offer exceptional discovery prospects, higher profits and lower taxes as compared to many parts of the world, and security of supply, (i.e. no risks of revolution, war, expropriation and, in Prudhoe Bay, the absence of the disruptions associated with off-shore operations.)

It appears on the hearing record that oil prices, the size of reserves and the costs of extraction will be far more critical in determining the magnitude of future oil exploration and development than the modest tax proposals before this committee.

In particular, weight should be given to the Administration's study (which used industry-based data), which shows that the severance tax proposal reduces DCF profits by less than 1%, a reduction which BP and SOHIO witnesses frankly stated would not cause them to halt investment in Prudhoe Bay or reduce present plans for exploration.

The claim by the industry that Alaska's oil and gas taxes are the highest in the nation, thereby lessening Alaska's competitive position, is contradicted by the Administration's claim that Alaska now ranks fourth among the states and would move to second with the passage of their bills.

In making its comparison, the Department of Revenue superimposed tax structures of other states on the production, income and property in Alaska. To be conservative, the Department excluded sales and use taxes, special pipeline taxes, and other taxes unique to other jurisdictions. The analysis of eight state tax commissioners appears to be more credible, but regardless of the past decisions of other states, Alaska is not and should not be bound by those past decisions alone.

First, the oil fields found in other states are now in large part in the later years of their life--smaller, and less profitable (often only stripper wells are involved).

Secondly, virtually all leases in the lower 48 states are on private rather than public lands and therefore do not involve the extraction of non-renewable resources belonging to all the people. The primary concern here is that the people of Alaska receive a satisfactory return for the extraction of non-renewable resources.

The industry contended that Alaska has all the revenues it needs, as proven by the prediction that a major "surplus" will accumulate in the Alaska Permanent Fund and the general fund.

Moreover, in recent statewide media presentations, the oil industry praises the Permanent Fund but makes much of the assertion that no legitimate purpose is given for the predicted surpluses.

Nevertheless, one of the major objectives of the Permanent Fund is to develop an economic base for Alaska beyond the monolithic oil industry. Viewed in this light, the use of oil revenues to diversify the Alaska economy is certainly as worthy a purpose as is, for example, Mobile Oil's recent takeover of Montgomery Wards.

The final shape of the Alaska Permanent Fund is open, but there is wide consensus that it can be used both to provide savings and income for the years after oil declines and to build a diversified, private economy and a new tax base. The capital projects from the general fund or bonding will hopefully compliment those broad goals. No one knows whether Alaska will, in fact, have a surplus; since no one knows, today, what will be the needs as oil production inevitably declines.

As for the problems of the Kenai-Cook Inlet operators, the Administration has pointed out that Federal price relief is available and that Federal controls may go on a stand-by basis in 1979 under the Energy Act. Yet there are delays in obtaining price relief, and the future of controls is uncertain. Moreover, as most of these fields are declining, it is sound policy to provide, in advance, that oil recovery and revenues be stretched out as long as possible.

Accordingly, a formula has been adopted that will immediately reduce severance taxes in the Kenai-Cook Inlet area and will, in future years, reduce the rates there more sharply than in other, more profitable areas.

It was argued by the industry that they were suffering an undue burden from taxation at existing rates. Specifically, the data in SOHIO Submission One reveals, according to Walter Levy & Associates, that the effective income tax on the oil industry under the current law will not exceed about 2.5%, as opposed to the 9.4% in the statute. The oil industry never denied that most Alaskan businesses pay a higher effective rate. This arises from the large subsidies in the Federal taxable income figure on which our tax is based today* and because the actual value of North Slope production is not reflected in oil property, sales, and payrolls in the state (the factors now used to divide income).

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In the course of the hearings, one major conflict kept emerging - the state's need for incentives versus the desires of Alaskans to turn oil capital, which can never be replaced, into uses that will provide benefits for the present and future generations.

It is the task of the Legislature to balance these desires, and the uncertainties that go with each of them.

Given the tax relief that the administration's severance tax proposal will afford the economically marginal oil and gas fields and the relatively modest increase in taxation the proposal places on the highly productive and profitable oil and gas fields, House Finance Committee Substitute for CS for SB 238* represents a balanced and reasonable adjustment to the present tax law.

HB 322, the corporate franchise tax, as well as HB 145, the direct accounting approach recommended by the Subcommittee on Oil and Gas Taxing and Leasing Policy, merely represent a mechanism to produce an effective rate equal to that which the present income tax law is supposed to recover for Alaska.

In light of the testimony and a thorough review of the analysis and study of tax proposals over the past three years, a majority of the members of the House Finance Committee recommends passage of HCS for CS for SB 238.



Rep. Steve Cowper, Chairman
House Finance Committee

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Footnotes

* No such agreement could exist, since Article IX, Section 1, of the Constitution of the State of Alaska prohibits the surrendering of the power of taxation.

* Last year, the largest oil companies in Alaska reported \$3 billion more income to stockholders than they were required to report to the I.R.S.

* House Finance Committee Substitute for CS for SB 238 is essentially the Governor's bill.

JOURNAL

MAJOR PROVISIONS OF THE OIL AND GAS PROPERTIES PRODUCTION TAX

*What about
Cook Inlet?*

The severance tax for oil is set at 12.5 percent of the wellhead value, or \$.9375 per barrel, whichever is higher. The cents-per-barrel "trigger" is set at a wellhead value floor of \$7.50, a floor which escalates at the rate of the GNP deflator. The floor, combined with the escalator, gives the state "downside protection" from the risks of changes in Federal pricing policy or attempts by the oil companies to shift costs from the fields to the pipeline and tankers (thus lowering wellhead values) or to move profits to the refinery, marketing, and distribution phases of their operations (thus lowering the profits exposed to taxes in Alaska). The \$7.50 floor was not criticized by the industry as unreasonable, and the escalator is seen as being essential to insure that Alaska's revenues keep pace with the rising value of Alaska's oil and to protect the purchasing power of the state's dollars.

*is, as you
get higher
the higher*

By raising the minimum economic limit factor (ELF) from 100 to 300 barrels, the special problems of marginal producers, such as those on the Kenai-Cook Inlet fields, are recognized. The ELF formula has been altered with an exponent that speeds the fall in severance tax for marginal fields.

The definitions of "gross value at the point of production" in Section 7 avoid the instability that came from the six years of litigation over the pricing of Cook Inlet oil.

7

The severance tax rate for gas is set at 10 percent of value, or \$.064 per thousand cubic feet, whichever is greater. Again, there is a floor under revenues, guarded by the GNP deflator. Again, because of the ELF formula, the less profitable a field, the more rapidly the severance tax ends. The former tax on all flared gas (a drafting error in the original bill) has been replaced by a penalty on gas use exceeding that allowed by the State Conservation Committee for safety flaring and for operating purposes on a lease.

HOUSE JOURNAL

OUTLINE OF HCS CSSB 238

The House Finance Committee Substitute for Committee Substitute for Senate Bill No. 238 provides for a production tax on oil and gas which has the following characteristics:

FOR OIL,

1. A 12.5% of value tax; or,
2. A \$.9375 per barrel tax (\$7.50 floor price), whichever is higher;
3. An escalator for the cents per barrel tax based on the GNP deflator;
4. An economic limit factor (ELF) which reduces the effective tax rate as production approaches the economic limit; and
 - (a) which presumes 300 barrels per day as the economic limit subject to the taxpayer demonstrating otherwise; and
 - (b) which contains an exponent that further reduces the effective rate for leases with an economic limit of less than 300 BPD; and
 - (c) which relies on the free market price of imported oil for determining the economic limit;
5. A definition of the point of production.

FOR GAS,

1. A 10% of value tax; or
2. A \$.064 per thousand cubic feet tax, whichever is higher;
3. An escalator for the cents per MCF tax based on the GNP deflator;
4. An economic limit factor which reduces the effective tax rate as production approaches the economic limit; and
 - (a) which requires a hearing to determine the economic limit; and
 - (b) which relies on the highest field price within 100 miles for such determination;
5. A penalty on gas flared in excess of that authorized for safety equal to the production tax on gas;
6. A definition of the point of production.

Prepared by:

Legislative Affairs Agency
Research Division 6 May 77

HOUSE JOURNAL

OUTLINE OF CSSB 238 am

The Senate Resources Committee Substitute for Senate Bill No. 238 as amended in the Senate provides for a production tax on oil and gas which has the following characteristics:

FOR OIL,

1. A 11.5% of value tax; or
2. A \$.75 per barrel tax (\$6.52 floor price), whichever is higher;
3. No escalator for the cents per barrel tax;
4. An economic limit factor (ELF) which reduces the effective tax rate as production approaches the economic limit; and
 - (a) which presumes 100 barrels per day as the economic limit subject to the taxpayer demonstrating otherwise; and
 - (b) which contains an exponent that further reduces the effective tax rate for leases with an economic limit of less than 750 BPD; and
 - (c) which relies on the free market price of imported oil for determining the economic limit;
5. No definition of the point of production.

FOR GAS,

1. A 10% of value tax; or
2. A \$.064 per thousand cubic feet tax, whichever is higher;
3. No escalator for the cents per MCF tax;
4. An economic limit factor which reduces the effective tax rate as production approaches the economic limit; and
 - (a) which requires a hearing to determine the economic limit; and
 - (b) ~~which relies on the highest field price within 100 miles for such determination;~~ no ↙
5. No penalty on gas flared in excess of that authorized for safety.
6. No definition of the point of production.

Prepared by:

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6 May 1977

HOUSE JOURNAL

EFFECTIVE SEVERANCE TAX RATES IN PERCENT FOR PRESENT LAW,
HOUSE FINANCE COMMITTEE SUBSTITUTE FOR
COMMITTEE SUBSTITUTE FOR SENATE BILL NO. 238,
AND
SENATE RESOURCES COMMITTEE SUBSTITUTE FOR SENATE BILL NO. 238 am

<u>Field Units</u>	<u>Present Law</u>	<u>House Finance CS CSSB 238</u>	<u>Senate Resources CSSB 238am</u>
Beaver Creek	8.3	0	1.1
Granite Point			
280001	7.7	5.5	2.3
280002	7.5	1.0	0.8
280012	7.0	0	0
280022	8.0	4.2	1.5
McArthur River			
520001	10.5	14.7	8.6
520002	9.0	5.6	2.3
520003	8.8	7.7	3.7
Middle Ground Shoal			
524001	5.6	1.8	1.0
524002	6.0	4.4	1.9
524003	5.8	5.0	2.5
524013	5.6	3.8	1.7
Swanson River			
772001	10.4	1.0	0.6
772002	0	0	0
Trading Bay			
800001	7.6	0	0.6
800002	7.2	0	0
800003	0	0	0
800004	8.5	0	0.1
800005	7.1	0	0
Production Weighted Kenai			
Cook Inlet Composite	8.9	8.4	4.9
Prudhoe Bay	7.7	12.2*	10.4*

*Assuming an economic limit of 750 bbl/day.

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HOUSE JOURNAL

COMPARISON OF TOTAL* SEVERANCE TAX REVENUES GENERATED BY PRESENT LAW,

HOUSE COMMITTEE SUBSTITUTE FOR COMMITTEE SUBSTITUTE FOR SENATE BILL NO. 238 AND COMMITTEE SUBSTITUTE FOR SENATE BILL NO. 238 AMENDED

<u>Field</u>	<u>Millions of Dollars*</u>		
	<u>Present Law</u>	<u>House Finance CS CSSB 238</u>	<u>Senate Resources CSSB 238am</u>
FY 1978:			
Kenai-			
Cook Inlet	23.5	22.3	13.1
Prudhoe Bay**	<u>171.4</u>	<u>270.8</u>	<u>227.8</u>
TOTAL	192.7	293.1	242.9
FY 1979:			
Kenai-			
Cook Inlet	19.6	19.0	11.1
Prudhoe Bay**	<u>255.8</u>	<u>397.6</u>	<u>349.4</u>
TOTAL	275.4	416.6	360.5
FY 1980:			
Kenai-			
Cook Inlet	18.2	16.3	9.3
Prudhoe Bay**	<u>303.7</u>	<u>471.9</u>	<u>413.6</u>
TOTAL	321.9	488.2	422.9
	790.0	1197.9	

* All figures are gross, EDIC has NOT been credited.

** Assume wellhead value at Prudhoe Bay Oil is \$7.38/bbl in FY78 with 5% inflation thereafter.
Assume economic limit at Prudhoe Bay is 750 bbl/day.

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Tax Comparison

