and our assumed schedule of depreciation. Our assumptions on TAPS tariffs (and, therefore, earnings) skew integrated earnings toward the production function. Hence, the DCF return on TAPS is slightly understated compared with a return that would be based on the maximum profits permitted by the I.C.C., and returns on production are slightly overstated. The cash flow stream on TAPS was raised for the years 1977-1981 by the estimated future benefits from ITC.

The stream of investments in the Prudhoe Bay field--again including all participants--is based on the major companies' past and prospective expenditures (1964-1978) for capacity of 1,500 TB/D. We have reduced the investment stream for tax benefits from the expensing of intangible development costs and have added payments of Alaskan reserves and property taxes in appropriate (pre-production) years. Investments for post-1978 years reflect our grossing up of ARCO's rough estimate of its costs (see Chapter I, North Slope Project: Evolution of Costs and Status of Construction). Our cost assumptions for the main field after 1978 exceed those employed by Alaska in its calculations of DCF rates of return on production. Since the major differences occur after 1981, and thus are heavily discounted, they do not greatly alter comparative returns. We have calculated cash flow on production under alternative tax assumptions, and for crude prices on the West Coast of $11.00 and $13.00 per barrel. We have raised our estimates of earnings based on normalized federal taxes to include ITC. However, we have not assumed continuing tax benefits from expensing of intangible development costs, since this provision remains under serious attack in the Congress. We have also included reimbursement of Alaskan reserves taxes (after payment of federal income taxes).

As expected, the contrast between returns on TAPS versus those on production is striking. We estimate the DCF rate of return on TAPS at 10%. Returns on oil production--under current tax laws--approximate 23%, given a crude price of $11.00 per barrel, and 27% if the crude price were $13.00 per barrel. The contrast between returns on production under current tax legislation versus returns arising under Alaska's proposed legislation is also noteworthy. Proposed Alaskan taxation would reduce returns on the field from 23% to 17.5% (assuming $11.00 per barrel for crude), and from 27% to 21.5% (assuming $13.00 for crude).

Upon combining investment and cash flow streams for TAPS and production, the integrated return--under present tax laws--approximates 14%, assuming $11.00 per barrel for crude on the West Coast, and 17% given a $13.00-per-barrel price.* Comparable

*We exclude the tanker leg of transportation for lack of information on earnings. In any event, while initial expenditures on tankers are important for analysis of company financing, the subsequent sale and lease back of tankers shifts this function to third parties. Ocean transportation thus becomes a cost of service to the North Slope operators.

returns under proposed tax changes would be 12% and 14%, respectively. In the current debate over Alaskan tax policy, the state is focusing on prospective returns on production. The companies, understandably, are emphasizing the total project rate of return. Investors in ARCO and Sohio are obviously interested in which viewpoint ultimately prevails.

DCF returns for the project as a whole may be taken as representative of returns for ARCO (and for Exxon). Sohio's indicated return on TAPS and production combined, given current tax laws and $11.00 per barrel for crude, would approximate 17% (versus 14% for the project) and 21%, given $13.00 for crude (versus 18% for the project).

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Addendum: Markets for North Slope Oil

This section briefly examines the scope of the West Coast market for North Slope crude during the early years of operation, the prospects for a crude surplus on the West Coast, and the implication for pricing of Prudhoe Bay crude of extending its reach to the Midwest. Sohio foresees a crude surplus of 300-600 TB/D in 1978 when TAPS capacity will be 1,200 TB/D, and as much as 600-800 TB/D in 1982, were TAPS throughput then to approach 1,800-2,000 TB/D (see table on page IV - 24).

Our three earnings models posit production of 600 TB/D for the second half of 1977, rising to 1,200 TB/D in 1978. Production in our "reserves constraint" model rises to a peak of 1,500 TB/D in 1980, as does output in our "production potential" model. The latter model's rate continues to grow, however, to a peak of 2 MM B/D in 1984. Production in our "market constraint" model holds at 1.2 MM B/D through 1980, then rises to its peak of 1.5 MM B/D in 1981.

The market for Prudhoe Bay crude on the West Coast is ascertainable only over a wide range. So, too, as noted earlier, is the prospective supply of North Slope crude. Estimates of product demand in District V are very diverse. For example, Sohio's projections of product demand on the West Coast for 1978 (2,800 TB/D) and 1982 (3,200 TB/D) are around 200 TB/D lower than earlier projections by Exxon and ARCO for those same two years. The outlook for product demand is particularly obscure, because (1) the recent recession has delayed clarification of the response of demand to quantum jumps in prices, (2) the demand pattern is expected to shift toward more rapid growth in fuel oil rather than in gasoline demand. Although not immediately relevant, it is worth noting that demand for petroleum products could slow dramatically after 1982 if El Paso's gas transmission proposal for North Slope gas is selected. In that event, any "surplus" of North Slope crude would likely persist on the West Coast into the late 1980's.

Demand for crude oil in District V will depend on the size and utilization of refinery capacity. Local refineries currently supply some 95% (2,200 TB/D) of West Coast product demand. Distillation capacity was 2,425 TB/D at the close of 1975; crude runs averaged 2,050 TB/D (for an average operating rate in 1975 of 85%). Refinery capacity will increase 415 TB/D (to 2,840 TB/D) in 1976--of which, Socal will account for 350 TB/D. Current firm projects will raise capacity by a modest 90 TB/D more by 1978-79. Sohio projects refinery capacity at 3,100-2,300 TB/D in 1982, assuming maintenance of the historic relationship between domestic and imported product supply. We would not be surprised to see capacity added at a slower rate owing to (1) persisting uncertainty over the course of demand, (2) disincentives implicit in price controls and allocations, and most important perhaps (3) the danger of divestiture. Whether tardiness in adding to refinery capacity would seriously retard expansion of North Slope production is questionable, however. Above-normal utilization of constrained capacity would allow considerable scope for growth in overall demand for crude oil.

Prospective demand for North Slope crude by West Coast refiners will, of course, reflect the aggregate effect of refiners' preferred mix of crudes. The key determinants in crude slates include (1) crude avails from alternative domestic

HYPOTHETICAL DISTRICT V CRUDE OIL BALANCE,
1975, 1978E, 1982E

(Thousands of Barrels Daily)

		1975	1978E	1982E
Product Demand		2,210	2,800	3,200
Crude Demand		2,050	2,475-2,550	2,800-2,900
Production:	Declining Fields	1,075	1,000	900
	Expansible Fields[a]	.....	175-325	350-400
Imports:	Canada	160	0-100	0
	Middle East	530	0	0
	Indonesia/Africa	320	450-550	400-500
Crude Supply ex North Slope		2,085	1,625-1,875	1,650-1,800
Crude Deficit ex North Slope		.....	600-925	1,000-1,250
North Slope Potential		.....	1,200	1,800
Crude Surplus on West Coast		.....	275-600	550-800

a. Elk Hills and Santa Ynez fields; for 1975 included in "declining field" category.

and foreign sources, (2) the flexibility of refineries for handling varying crudes (particularly, their pollutants), (3) ownership of alternative supplies and related crude-swap arrangements, (4) relative crude prices, and (5) considerations of security of supply.

As for local supply, District V crude production has been suffering natural decline for a number of years. Sohio projects a decline in production from known fields from 1,075 TB/D currently, to 1,000 TB/D in 1978, and to 900 TB/D by 1982. It estimates production from the Elk Hills naval reserves and Santa Ynez area of 175-325 TB/D in 1978 and 350-400 TB/D by 1982. New finds could add untold millions of barrels to reserves by 1982, but any number would represent sheer speculation. Given development lag on the West Coast, however, even large discoveries might not be readily expansible by the early 1980's.

The refineries clustered in the Puget Sound area will represent a prime outlet on the West Coast for Prudhoe Bay crude. Crude capacity in the area is around 340 TB/D; runs recently averaged 310 TB/D. ARCO has a 96 TB/D refinery at Cherry Point, Washington (in addition to the 185,000-barrel-a-day plant at Watson, California). Crude supplies in this area were recently 50% from Canada (delivered via the Trans Mountain Pipeline), 50% overseas imports. Canadian supply is being phased out (Sohio projects 0-100 TB/D from Canada for 1978, 0 for 1982). Most refiners will require investment in desulphurization facilities in order to handle Prudhoe Bay crude. Those investments are in abeyance pending removal of potential impediments to tanker traffic in the Sound (i.e., limitations on tanker size and constraints on expansion of terminals). The pace at which Puget Sound refiners utilize Prudhoe Bay crude will depend on clarification of these issues.

For 1978, if one could presuppose the backing out of crude imports, the West Coast market could readily accommodate 1,200 TB/D of Prudhoe Bay crude and possibly more. Sohio does project the displacement of imported "sour" crudes.* Refiners will little direct interest in Middle East crudes should clearly prefer Prudhoe Bay crude: it will be cheaper--at least in 1977-78, and offers security of supply. At the same time, Sohio foresees an increase in imports of "sweet" crudes from 320 TB/D to 450-550 TB/D. Unless all facilities are modified to handle "sour" crudes, refiners will require access particularly to Indonesian crude. Moreover, major West Coast refiners--Socal, Union, even ARCO--are also significant crude producers in Indonesia and will have an economic (and political) preferance for the latter over Alaskan crude.

The companies have every interest in timely completion of a transportation network from the West Coast to Midwest markets so as to maximize the present value of the Prudhoe Bay earnings stream. Accordingly, the companies have been considering alternative methods of moving Prudhoe Bay to U.S. markets East of the Rockies. Among the options considered is the possibility of reversing the (Canadian) Trans-Mountain or the Four Corners pipelines; these would offer only quite limited flows of Alaskan oil. The companies have also considered construction of large diameter, trans-continental lines, originating in northern California, western Mexico to the U.S. midcontinent/midwest area. In addition, the companies have pondered largely tanker routes--trans Isthmus (with a short pipeline across Central America) and via Cape Horn to eastern U.S. markets.

Sohio, with the largest share of Prudhoe Bay crude, and no controlled outlets on the West Coast, is implementing its own plan for moving Alaskan crude across the continent. The key element of the proposal is reversal of a 30-inch El Paso (Texas to California) gas line. The project would require construction of an oil line from California to the Arizona border (or possible reversal of another gas line to link up with El Paso's system). The FPC is expected to reach

* Crude imports into District V for 1975 divided as follows: Canada 160 TB/D, Middle East (mostly "sour" crudes) 530 TB/D, Indonesian and African "sweet" crudes, 320 TB/D.

its decision on interruption of gas service on the El Paso line by mid-1976. The Department of the Interior is preparing an environmental impact statement on the project. Sohio's proposal includes expansion of the marine terminal in the Santa Barbara Channel. Several layers of California environmental bureaucracy must pass on these plans. The expansion, moreover, appears to be prohibited by the State's two-year moratorium on industrial construction in the coastal zone. Federal legislation will probably be needed to untangle the local regulatory knots; it may not come quickly enough to avoid a potential surplus and holddown on production in 1978 to less than 1.2 million B/D. Sohio's proposal has certain advantages over alternatives: (1) it represents the most economical method of reaching major markets, (2) it will require the least direct capital commitment--a prime consideration in view of the companies' already onerous financing burdens, the possible variability in utilization of the line, and the threat of eventual divestiture.

The project, as originally conceived, might require an investment of $500 million for capacity of 500 TB/D (and $300 million more for expansion to 2 million B/D). Financing requirements in 1976 might not exceed $15 million, but will jump sharply in 1977. Sohio will probably require assistance from the federal government in clearing away local obstacles to terminal and pipeline construction. We assume that by 1979 at the latest, outlets to East of Rockies markets would be in place. One may even reasonably hope for completion of such transport network in 1978. Federal assistance in attaining access to all domestic markets might appear to be a reasonable counterbalance to federal restrictions on exports of North Slope crude.

Crude Pricing Implications

Were Prudhoe Bay crude to move only to West Coast markets, then its value would be set unambiguously by the imported price (or prescribed price) of crude on the West Coast, less transportation charges from wellhead to market. Should Prudhoe Bay crude move in quantity to the Midwest, however, it would take its value from the imported (or prescribed) price in that more distant market less transportation costs from wellhead to the Midwest. The delivered value of imported crude in each of these major markets would include the same f.o.b. price (Persian Gulf) plus transportation costs to respective markets. In the case of the West Coast market, light Arabian crude would lay in at $13.00 per barrel ($11.51 f.o.b., $1.14 tanker freight at Worldscale 60, plus $0.35 import fee); in the case of the Midwest, it would lay in at $13.50 per barrel ($11.51 f.o.b., $1.24 tanker freight to Gulf Coast at Worldscale 60, $0.40 pipeline charge from Gulf Coast to Midwest, plus $0.35 import fee). The difference in transportation cost, and hence in delivered cost, of imported crude amounts to roughly $0.50 per barrel. It follows that netbacks on Prudhoe Bay crude from the Midwest and the West Coast would be identical only if the difference in transportation costs to these markets were equivalent to the difference in transportation costs on imported crude to these same markets. In fact, the cost of moving Prudhoe Bay crude from Valdez to southern California would amount to $0.50 per barrel, and from Valdez to Chicago around $1.50 per barrel ($0.50 tanker freight Valdez to California, $0.60 pipeline cost California to Midland, Texas and $0.40 pipeline cost Midland to Chicago area) for a difference of $1.00 per barrel.

NETBACKS ON PRUDHOE BAY CRUDE FROM MAJOR MARKETS

(Dollars per Barrel)

	Delivered Cost of Persian Gulf Oil[a]	Cost of Moving Alaskan Oil From Valdez To Destination	Alaskan Price at Valdez to Equate with Cost of PG Oil
Los Angeles	$13.00	$0.50	$12.50
Chicago	13.50	1.50	12.00

a. At current AFRA, Worlscale 60.

In southern California, Prudhoe Bay crude would net back from Chicago at $0.50 per barrel below the ceiling set by the delivered cost of Persian Gulf crude on the West Coast. Given the more favorable netback from West Coast markets, North Slope producers would clearly maximize their earnings by practicing classic price discrimination (by charging West Coast customers the equivalent of the cost of imports, and by charging customers in the Midwest $0.50 less--on the f.o.b. price or on pipeline transportation--so as to compete with imported crude in the Midwest). Unfortunately for the North Slope producers, such practice would confront effective regulatory and political opposition. In a free market, Prudhoe Bay crude, selling below parity with imports on the West Coast, would tend to enlarge its markets there by driving out imports and its price would tend to rise toward parity with imported crude.

However, if prices of domestic crude are constrained below import parity, as we deem likely, then the movement of Prudhoe Bay into the more distant markets would not likely result in a lower netback than if Alaskan oil were marketed solely on the West Coast. Given the umbrella of higher prices for imported crude than those prescribed for domestic crude, the price of Prudhoe Bay crude in Chicago would be its delivered cost to the West Coast <u>plus</u> full transportation cost to the Chicago area.

COMPANY EARNINGS ON NORTH SLOPE CRUDE

Introduction and Summary

In this section, we translate our three basic earnings models into North Slope-related earnings per share for Atlantic Richfield and Standard Oil of Ohio. For each model, we multiply per-barrel earnings on TAPS, Sadlerochit production, and Kuparuk/Lisburne production by corresponding pipeline throughputs and production volumes of the companies. The reader is urged to see Appendix Tables VI - A to VII - L for the matrix of earnings possibilities. The range of plausible earnings estimates is disturbingly large. The following analysis is deliberately neutral. A positive position on the stocks presupposes a bias toward a favorable configuration of North Slope production and crude prices and tolerable taxation in Alaska.

In our "reserves constraint" model, ARCO's pipeline throughput builds up rapidly to a peak of 315 TB/D by 1979, and its net production to 268 TB/D. In our "production potential" model, ARCO's pipeline throughput peaks in 1984 at 420 TB/D (one third higher than in the "reserves constraint" model) while its net production gains even more rapidly (+50%) to 403 TB/D. The hefty gains in throughput and production is largely attributable to tentative increments from the Kuparuk/Lisburne reservoirs.

Given $11.00 a barrel for crude on the West Coast, in our "reserves constraint" model, ARCO's earnings per share in 1978 on North Slope oil would approximate $4.30 (divided $1.34 on TAPS and $2.97 at the wellhead). Subsequent rapid expansion of TAPS throughput and production would raise ARCO's per share earnings by 1980 to $5.77 and by 1985 to $5.92. In contrast, ARCO's 1985 earnings in the "production potential" model soar to $8.42 per share (42% above 1985 results in the "reserves constraint" model) reflecting mainly the assumed buildup of Kuparuk/Lisburne production, so important to ARCO. If Alaskan tax proposals were adopted unaltered, ARCO's earning power on integrated operations would shrink by roughly 20% below the foregoing estimates. In our "reserves constraint" model for 1980, a $1.00-a-barrel increase or decrease in the market price of crude would benefit or penalize ARCO's earnings by $0.78 per share under current tax parameters, but by $0.46-$0.56 per share under proposed tax laws. In addition to "normalized" earnings discussed above, tax savings accruing to ARCO from ITC and reimbursement of Alaskan reserves taxes could approximate $1.00 per share in 1978 and 1979, and $0.50 per share in 1980 and 1981.

Sohio is the leveraged vehicle for investment in North Slope equities. In our "reserves constraint" model, Sohio's pipeline throughput builds up rapidly to a peak of 500 TB/D by 1979 and its net production to an impressive 627 TB/D. The benefit of Sohio's disproportionately large equity in main field production compared with ARCO is readily apparent. In our "production potential" model, Sohio's pipeline throughput continues to surge beyond the 500 TB/D mark to a peak of 667 TB/D by 1984; its net production also continues to grow--but at a slower pace--to 674 TB/D. The more rapid gain in TAPS throughput compared with production reflects the major role of Kuparuk/Lisburne production in expanding pipeline throughput and Sohio's minor equity in those reservoirs.

from 1.9 billion barrels). ARCO's share of Kuparuk/Lisburne crude is expected to be much higher--possibly one-third. While ARCO has speculated publicly as to the production potential of the Kuparuk/Lisburne reservoirs, it has not disclosed the assumptions about reserves underlying that estimate. Given the substantial potential of the Kuparuk/Lisburne formations, ARCO's relatively high interest in those reservoirs, and its lower interest in Sadlerochit crude, Kuparuk/Lisburne crude looms large in ARCO's overall North Slope crude potential. Nevertheless, Kuparuk/Lisburne production will not contribute quite so importantly to ARCO's aggregate earnings on North Slope crude owing to its probably higher cost as compared to Sadlerochit supply.

As noted, Sohio's acreage covers approximately 54% of the crude and condensate reserves (before deduction of Alaskan royalty oil and BP's net profits royalty interest) in the Sadlerochit reservoir. Sohio's exact equity in Sadlerochit reserves is now indeterminate since BP's net profits royalty interest depends on production levels which cannot be projected precisely. Sohio is entitled to 100% of the profits on its net production (after Alaskan royalty) up to 600 TB/D, (i.e., when gross reservoir production reaches 1,270 TB/D). On Sohio's net production above 600 TB/D to 1,000 TB/D (i.e., if gross reservoir production is between 1,270 TB/D and 2,115 TB/D), BP receives 75% of net profits and Sohio 25%. Gross production from Sadlerochit's proven reserves of 9.5 billion barrels is expected to reach 1,500 TB/D for 6 to 8 years and then to decline gradually (our "reserves constraint" model). Sohio's 54% share of Sadlerochit reserves (after deduction of Alaskan royalty oil) equals 4,490 million barrels. Given our projected profile of production from the 9.5 billion barrels of proven reserves, BP's cumulative net profits royalty interest in barrel equivalents amounts to 230 million barrels; Sohio's net reserves approximate 4,260 million barrels, or 95% of the two companies' combined reserves. A higher level of peak production, say of 1,600 TB/D for 6-8 years, would raise BP's share and reduce Sohio's net reserves by close to 100 million barrels.

Tertiary recovery would further complicate assessment of Sohio's true equity in Sadlerochit reserves. First, the size of tertiary reserves and resulting increments to production remain speculative. Second, the division of production and reserves between Sohio and BP would depend on levels of Sohio's net production in particular years. In years when primary/secondary production from the main field was already above 600 TB/D to Sohio, incremental production from tertiary reserves would accrue 75% to BP and 25% to Sohio. In contrast, in years when Sohio's net production (before tertiary production) was below 600 TB/D, increments to production from tertiary recovery would accrue 100% to Sohio until the 600 TB/D level were reached and 75% to BP and 25% to Sohio on increments above 600 TB/D. Given our profile of production in the "production potential" case, in which tertiary reserves serve to lift production from the main field by a maximum of 100 TB/D, Sohio's reserves (after deduction of royalty oil and BP's net profits interest) in the main reservoir would approximate 4,960 million barrels. Sohio's equity in the Kuparuk/Lisburne reserves is expected to be relatively small--perhaps on the order of 10%, or 175 million net barrels from assumed gross reserves of 2 billion barrels. BP might share a small fraction of Sohio's interest in the Kuparuk/Lisburne reservoirs.

COMPANY EQUITIES IN TAPS VERSUS PRUDHOE BAY PRODUCTION, 1978 and 1985

	Initial TAPS Equity	Gross Production	Net Production
		ATLANTIC RICHFIELD	
		"Reserves Constraint" Model	
1978	21.0%	20.4%	17.8%
1985	21.0	20.4	17.8
		"Production Potential" Model	
1978	21.0%	20.4%	17.8%
1985	21.0	22.3	20.1
		"Market Constraint" Model	
1978	21.0%	20.4%	17.8%
1985	21.0	23.0	20.1
		STANDARD OIL OF OHIO	
		"Reserves Constraint" Model	
1978	33.3%	54.0%	47.2%
1985	33.3	47.8	41.8
		"Production Potential" Model	
1978	33.3%	54.0%	47.2%
1985	33.3	38.5	33.7
		"Market Constraint" Model	
1978	33.3%	54.0%	47.2%
1985	33.3	45.2	39.5

Given $11.00 a barrel for crude on the West Coast, in our "reserves constraint" model, Sohio's earnings per share in 1978 would approximate $9.55 (divided $2.03 on TAPS and $7.52 at the wellhead), rising to $11.18 by 1980 and to $11.51 by 1985. In contrast, Sohio's per share earnings for 1985 in our "production potential" model approximate $13.35 (some 16% above 1985 results in the "reserves constraint" model). Adoption of proposed Alaskan taxes would effectively reduce the above estimates by 23%-25%. In our "reserves constraint" model, a $1.00-per-barrel change in crude price under current tax regimes would benefit or penalize Sohio's prospective earnings on the North Slope by $1.70 per share ($1.00-$1.24 per share under proposed taxation in Alaska). In addition to normalized earnings, Sohio's tax savings could amount to roughly $1.95 per share in 1978 and 1979 and $0.85 per share in 1980 and 1981.

Equities in TAPS

Company earnings on TAPS will, of course, depend importantly on eventual equity shares in the pipeline system. Present equities in TAPS--revised in July 1974 to more closely reflect the companies' equities in Sadlerochit crude reserves --have been agreed upon only for initial capacity of 1.2 million B/D. ARCO's 21% share is close to its 20.4% equity in the 9.5 billion barrels of proved crude and condensate reserves in the Sadlerochit (main) reservoir. In contrast, Sohio's 33.34% initial equity in TAPS remains well below its 54% equity in Sadlerochit reserves (before Alaskan royalty and BP's net profits royalty interest). Sohio and BP together, however, hold 49.2% of TAPS.

Initial equities in TAPS for both ARCO and Sohio now look to be below their shares in posited gross production from the three Prudhoe Bay reservoirs. ARCO's 21% share of TAPS compares with 22.3% of peak gross production from the three Prudhoe Bay reservoirs in our "production potential" case; Sohio's 33.34% equity in TAPS compares with our estimate of 38.5% of gross production. It is worth noting, however, that on excluding Alaskan royalty oil the companies' current equities in TAPS do not differ significantly from their indicated interests in net peak production from the three major reservoirs.

Differences between the companies' initial equities in TAPS and their equities in gross field production reflect our own assumptions as to the production potential of the Prudhoe Bay reservoirs. Moreover, final equities in Sadlerochit reserves await completion of the unitization agreement; equities in Kuparuk/Lisburne crude are much more tentative. Once equities in Prudhoe Bay crude are well-established, equities of ARCO and Sohio in TAPS might be raised upon expansion of the system from 1.2 to 2.0 million B/D. On the other hand, should Alaska prove willing, and financially capable, to participate in the expansion of TAPS, the companies might well accommodate the state's participation. (Such participation may find the state much more sympathetic towards the prospective rate of return on pipeline investment than in the past.) For the present exercise we assume no change in TAPS equities upon pipeline expansion.

Equities in Prudhoe Bay Reserves and Production

Atlantic Richfield's acreage covers approximately 20.4% of the crude and condensate reserves in the Sadlerochit reservoir; its estimated net reserves of crude and natural gas liquids are 1.72 billion barrels (revised downward in 1974

Chapter VII

Drexel Burnham & Co.

NORTH SLOPE FINANCING

·duction and Summary

In this chapter we examine the captial requirements of Atlantic Richfield tandard Oil of Ohio for bringing North Slope oil on stream, the possible ibutions to these requirements of internally-generated cash flows during emaining pre-production period, and their requirements for external finan- We review the companies' borrowings to date, other sources of capital have been arranged, additional financing requirements, and possible options btaining additional funds. Our analysis of uses of funds, as for sources nds, includes the requirements of ongoing and projected operations apart the North Slope.

ARCO is fundamentally better positioned than Sohio to meet its capital rements for the North Slope without resort to ostensibly unorthodox financing ·troleum industry standards) in the form of extraordinary reliance on apital. Any further big increase in cost estimates or protracted delay in ·ting TAPS would find Sohio's capital requirements increased by a disturbingly degree. However, we regard both risks as minor. Unfunded capital require- of Atlantic Richfield for 1976-77 approximate $330 million; Sohio's approach illion. Fortunately, the real collateral behind the debt of both companies-- proved reserves of oil at Prudhoe Bay--will facilitate prospective financing ltional capital requirements during the remaining pre-production period h further additions to funded debt or the arrangement of production payments ·tially advance sales of crude).

The companies will probably be reluctant to resort to additional equity ing in the near future, chiefly in view of adequate recourse to other finan- ptions. They may hope for an eventual renewal of investor confidence and anying improvement in prices of their shares based on (1) possible modera- f Alaskan tax demands, (2) start-up of Prudhoe Bay production, and (3) the interim resurgence in reported earnings. However, equity financings in 8 are becoming increasingly probable in light of the growing role of debt off both companies' balance sheets and the likelihood of continued heavy ng on the North Slope and related facilities after the start-up of pro- n in mid-1977.

ic Richfield

Full-scale development of North Slope resources will find Atlantic ld ranking in the top tier of large, highly-integrated refiner/marketers United States. In the early 1980's, ARCO's refining capacity in the States will approximate 775 TB/D (after divestment of its East Chicago y); the company's net crude production could then exceed 750 TB/D.

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In effect, ARCO will have attained enviable balance in the United States while integration ratios of its peers continue to erode. Already among the nation's top producers of natural gas, ARCO will achieve preeminence (surpassed only by Exxon and Texaco) in that area. Meanwhile, the company is expanding on many fronts--in domestic oil and gas exploration apart from the North Slope, in petrochemicals and in foreign exploration and development. The company is also gearing up for development of its extensive coal reserves in the West, and for possible entry into the uranium-enrichment business.

ARCO has been fundamentally better positioned than Sohio to meet its capital requirements for the North Slope project without resort to exceptional dependence on debt financing. ARCO's cumulative financial needs for the North Slope including pre-production taxes may approximate $3 billion in the period 1969-1977; Sohio's requirements, in contrast, could reach $5.2 billion. ARCO's net book value at year-end 1975 was $3.7 billion and its debt ratio was 30%; Sohio's net book value was $1.5 billion and its debt ratio already 57%. ARCO's cash flow from operations in the remaining pre-production years, 1976-77, could amount to $2.1 billion compared with Sohio's potential cash flow of $480 million.

Pre-Production Expenditures and Financing:
1976-1977

As noted, ARCO's cumulative expenditures on the North Slope project through 1977 might approach $3 billion, divided $1.7 billion (59%) on TAPS, $305 million (10%) on tankers, and $915 million (31%) on development of the main reservoir. The $915 million for development includes $770 million for capital and $145 million of Alaskan pre-production taxes.

Of ARCO's total outlay for TAPS of $1.7 billion (which includes the company's 21% share of capital and construction interest for pipeline capacity of 1.2 million B/D, and pre-start-up property taxes) through 1977, $770 million will be spent in the remaining pre-production years 1976 and 1977.*

Of the total $305 million of outlays on tankers over the 1969-77 period, roughly $120 million remains to be spent this year and next. While tanker financing is taking the form of life-of-vessel charters rather than direct ownership, and while investments in tankers do not appear on the company's balance sheet, they represent very real long-term obligations of the company.

Of ARCO's total spending of $915 million for main field development in the 1969-77 period, $565 million will be spent during the remaining pre-production period; $430 million represents capital, and $135 million, Alaskan taxes.

*We assume that full-year 1977 capital requirements will have to be financed prior to mid-year startup of TAPS.

ATLANTIC RICHFIELD

ESTIMATED CAPITAL AND OTHER EXPENDITURES
ON THE NORTH SLOPE PROJECT, 1969-1977

(Millions of Dollars)

	Spent 1969-1975	Pre-Production 1976-77	Grand Total 1969-1977
S[a]	$ 985	$ 770	$1,755
ital	900	570	1,470
struction Interest	75	155	230
perty Tax	10	45	55
kers	$ 185	$ 120	$ 305
ital	160	105	265
struction Interest	25	15	40
hoe Bay Field[b]	$ 350	$ 565	$ 915
ital	340	430	770
erty Tax	10	15	25
Reserves Tax	...	120	120
ject Total	$1,520	$1,455	$2,975

TAPS Capacity of 1.2 MM B/D.

Development of main field to capacity of 1.5 MM B/D.

Continued......................

ATLANTIC RICHFIELD

PROJECTED USES, INTERNAL SOURCES OF FUNDS AND EXTERNAL FINANCING REQUIREMENTS
1976-77

(Millions of Dollars)

	1976	1977	Cumulative 1976-1977
Uses of Funds:			
TAPS Capital[a]	$ 435	$ 135	$ 570
TAPS Construction Interest	100	55	155
Tankers[b]	45	75	120
Prudhoe Development[c]	330	100	430
Alaskan Taxes[d]	85	95	180
TOTAL NORTH SLOPE	$ 995	$ 460	$1,455
Other Capital Expenditures	$1,005	$1,040	$2,045
Debt Repayment	117	24	141
Dividends	145	145	290
TOTAL	$2,262	$1,669	$3,931
Internal Sources of Funds:			
Earnings	$ 366	$ 420	$ 786
Non-cash Charges	655	675	1,330
BP Notes	58	...	58
TOTAL	$1,079	$1,095	$2,174
External Financing Requirements	$1,183	$ 574	$1,757

a. For TAPS capacity of 1.2 MM B/D.

b. Includes construction interest.

c. Development of main field to capacity of 1.5 MM B/D.

d. Pre-production property and oil reserves taxes.

AGO 531588

ARCO is employing traditional high debt financing for TAPS and, as ted, off-balance-sheet debt for tankers in the form of long-term leases on sels. The bulk of the debt required to finance its share of TAPS capacity 1.2 million B/D has already been raised. Financing of tanker requirements also been arranged.

Of the total outlay of $1.7 billion required for TAPS in 1976 and 7, we assume that 85%, or $1,445 million, will be debt and that 15%, or 5 million, will be equity capital.* To date, ARCO has raised $1,310 million ium-term debt (including a $250-million revolving credit convertible to a ear loan prior to end-1978, and $150 million in 4-year Eurodollar credits). s, ARCO has yet to raise some $135 million in debt and $255 million in equity ital for TAPS prior to 1977 startup.

ARCO's other corporate uses of funds during the remaining pre-production iod could total $3,248 million, which, when combined with remaining TAPS uirements of $390 million, raise financing requirements for 1976-77 to 638 million. ARCO's sources of funds apart from TAPS debt and tanker ncing might total $3,307 million in 1976-77. The total includes estimated flow from operations ($2,116 million); outstanding BP notes ($58 million); pended debt-equivalents for chemical facilities ($300 million); sale of jor carved-out production payment ($420 million); advance sales of gas ($250 lion); sale of the East Chicago refinery; and related inventories ($140 million); sale of ARCO's petroleum operations in the Province of Saskatchewan million).**

ARCO's unfunded capital requirements in 1976 and 1977 work out to $331 mil- --$196 million if unfunded debt for TAPS is excluded. ARCO could resort to riety of financing options--including additional debt or advance crude sales-- ise this relatively small amount of capital. It may also be noted that the ny is discussing the sale of its remaining petroleum operations in Canada to national oil company. ARCO had valued its Canadian properties at $400 million r to the recent sale of its interest in Saskatchewan for $23 million.

CO may decide to fund TAPS with 10% equity capital and 90% debt.

allowance by the FPC of inclusion of advance payments for gas commitments in eline rate bases led to the cancellation of $720 million in advances to ARCO. recent advance sales of gas in the lower-48 states and sale of a production ment compensated for the bulk of this loss.

AGO 531589

ATLANTIC RICHFIELD

TAPS AND OTHER FINANCING:
ADDITIONAL PRE-PRODUCTION FUNDING REQUIREMENTS

(Millions of Dollars)

	TAPS Capital Requirements, 1969-1977	$1,700
(1)	TAPS Equity Requirement	$ 255
(2)	TAPS Debt Requirement	$1,445
	TAPS Debt Financing	
	ARCO Pipe Line 7% bank note due 3/6/78	$ 25
	ARCO Pipe Line 7½% bank note due 2/5/80	25
	ARCO Pipe Line 7 3/4% notes due 6/1/98	40
	11/1/74 ARCO Pipe Line 8.7% notes due 11/1/81	200
	1/15/75 ARCO Pipe Line 8% notes due 1/15/82	250
	7/16/75 ARCO Pipe Line 8 3/8% notes due 7/15/83	250
	1/1/75 ARCO Pipe Line, revolving credit convertible to 3-year term loan prior to end-1978	250
	Early 1975 4-year Eurodollar credits from Canadian and European banks	150
	1/27/76 ARCO Pipe Line 8% notes due 2/1/84	200
		$1,390
	Less: Repayment of Short-term Bank Debt	80
(3)	TAPS Debt Financing to date	$1,310
(4)	(2)-(3) TAPS Debt Requirement less Financing to date	$ 135
	Other Corporate Uses of Funds, 1976-1977 (ex TAPS and Tankers)	
	North Slope	$ 610
	Other Capital Expenditures	2,045
	Purchases of 6 million Common Shares of Anaconda at $27/sh.	162
	Debt Repayment	141
	Dividends	290
(5)	Total Other Corporate Uses of Funds	$3,248
	Other Sources of Funds, 1976-1977	
	Corporate Cash Flow	$2,116
	BP Notes	58
	Approximate Unexpended Private Debt for Chemicals	300
	12/5/75 Sale of Production Payment	420
	Advance Sales of Gas in Lower-48 States	250
	Sale of East Chicago Refinery and inventories	140
	Sale of Petroleum Interests in Saskatchewan	23
(6)	Total Other Corporate Sources of Funds	$3,307
(7)	(1+4+5-6) Additional Financing Requirements, 1976-1977	$ 331

AGO 531590

ATLANTIC RICHFIELD

POSSIBLE IMPACT OF TAPS DELAY ON FINANCING REQUIREMENTS*

(Millions of Dollars)

Capital Costs[a]	$100
Construction Interest on TAPS	115
Property Taxes	40
One-half of 1978 Spending[b]	235
Increment	$490

One year delay.
Speculative.
Excludes possible expenditures on lower-48 pipeline.

We estimate that a full year's delay in bringing North Slope crude on stream ıld add approximately $490 million to ARCO's preproduction expenditures. As noted ·lier, chances of such delay--let alone a protracted delay--now appear minimal.

A Glimpse Beyond 1977

Although ARCO's prospective cash flow from North Slope operations is very ressive, continuing outlays on the project may prove to be almost equally im-ssive, particularly if the company undertakes development of the Kuparuk and burne reservoirs, tertiary recovery in the Sadlerochit reservoir, early develop-t of natural gas, and construction of a pipeline system to East-of-Rockies markets e table on next page).

ATLANTIC RICHFIELD

NORTH SLOPE CASH FLOW AND POSSIBLE CAPITAL EXPENDITURES,
1978-1983

(Millions of Dollars)

	1978	1979	1980	1981	1982	1983
"Reserves Constraint" Case						
Cash Flow[a]	415	532	507	508	484	491
Possible Capital Outlays	470	82	125	380	380	50
Main Field/TAPS/T	470	82	50	50	50	50
Gas Development	...	...	...	330	330	...
"Production Potential" Case						
Cash Flow[a]	404	519	520	618	691	722
Possible Capital Outlays	760	372	415	960	710	380
Main Field/TAPS/T	470	82	725	50	50	50
Lower-48 Pipeline	40	40	40	...	...	...
Lisburne/Kuparuk	250	250	250	250	...	...
Tertiary Recovery	...	...	...	330	330	330
Gas Development	...	...	...	330	330	...
"Market Constraint" Case						
Cash Flow[a]	412	421	393	560	516	520
Possible Capital Outlays	470	332	300	630	630	50
Main Field/TAPS/T	470	82	50	50	50	50
Lisburne/Kuparuk	...	250	250	250	250	...
Gas Development	...	...	...	330	330	...

a. Cash flow includes investment tax credits for the period 1978-1981 and reimbursement of Alaskan reserves taxes in 1978 and 1979. Earnings included in cash flow assume $11.00-per-barrel crude price and current tax laws.

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INCORPORATED

tandard Oil of Ohio

Sohio's prospective transformation from a severely crude-deficient, regional ·finer/marketer of medium size (with supporting interests in coal, chemicals, and ›reign production) into a crude-rich integrated major is being accompanied by severe owing pains.

Sohio's capital commitment on the North Slope is huge both in absolute terms ·l relative to its capital base. As already noted, the company's cumulative expen- tures on the North Slope project through 1977 could reach $5.2 billion. In contrast, hio's net book value at end-1975 was $1.5 billion; its debt-to-capital ratio was al- ady 57% and headed a bit higher. More disturbing to investors, Sohio's capital re- irements have continued to grow in discrete chunks owing in part to inflation and part to catch up for early delays in constructing TAPS. In addition, Alaska has posed an onerous tax on oil reserves, payable prior to the startup of North Slope erations. A major concern of investors--now ebbing--has centered on the potential- large increment to pre-production costs, and external financing requirements, from ssible delay in bringing North Slope crude on stream. If such delay were open- 'ed, then Sohio might face a true financial crisis. As noted earlier, the proba- 'ity of a protracted delay in completion of the North Slope project appears slim.

STANDARD OIL OF OHIO

ESTIMATED CAPITAL AND OTHER EXPENDITURES
ON THE NORTH SLOPE PROJECT, 1969 - 1977

(Millions of Dollars)

	Spent 1969-1975	Pre-Production 1976-1977	Grand Total 1969-1977
S[a]	$1,593	$1,252	$2,845
ital	1,407	928	2,335
truction Interest	171	254	425
perty Tax	15	70	85
ers	$ 233	$ 391	$ 624
tal	208	320	528
truction Interest	25	71	96
hoe Bay Field[b]	$ 755	$ 995	$1,750
tal	740	705	1,445
erty Tax	15	30	45
Reserves Tax	...	260	260
ct Total	$2,581	$2,638	$5,219

TAPS capacity of 1.2 MM B/D.
Development of main field to capacity of 1.5 MM B/D.

STANDARD OIL OF OHIO

PROJECTED USES, INTERNAL SOURCES OF FUNDS AND EXTERNAL FINANCING REQUIREMENTS
1976-1977

(Millions of Dollars)

	1976	1977	Cumulative 1976-1977
Uses of Funds:			
TAPS Capital[a]	$ 675	$ 253	$ 928
TAPS Construction Interest	195	59	254
Tankers[b]	216	175	391
Prudhoe Development[c]	400	305	705
Alaskan Taxes [d]	175	185	360
TOTAL NORTH SLOPE	$1,661	$ 977	$2,638
Other Capital Expenditures	120	90	210
Debt Repayment	11	18	29
Dividends	50	50	100
TOTAL	$1,842	$1,135	$2,977
Internal Sources of Funds:			
Earnings	$ 131	$ 138	$ 269
Non-cash Charges	105	105	210
TOTAL	$ 236	$ 243	$ 479
External Financial Requirements	$1,606	$ 892	$2,498

a. For TAPS capacity of 1.2 MM B/D.

b. Includes construction interest.

c. Development of main field to capacity of 1.5 MM B/D.

d. Pre-production property and oil reserves taxes.

AGO 531594

Of the $5.2 billion committed for the period 1969-77, TAPS will account for 45 million (54%), tankers for $624 million (12%), and development of the main hoe Bay field for $1,750 million (34%).

Of the TAPS total of $2,845 million (which includes Sohio's 33.34% share of tal and construction interest for a 1.2 million-B/D pipeline and pre-startup erty taxes), $1,252 million will be spent in the remaining pre-production years -77.* Of the total $624 million for tankers, $391 million will be spent in -77. Of the total $1,750 million projected for main field development, some million remained to be spent during the pre-production years 1976-77. It is h noting that of this $995 million, some $705 million represents actual capital irements, while $290 million will be for Alaskan taxes.

Thus far, Sohio has relied very heavily on debt to finance its North Slope irements. Pipeline and tanker costs account for a hefty chunk (66%) of total ncial requirements through 1977, with traditional methods of financing pipelines tankers accounting for the preponderance of debt issuance to date. High debt/ ty ratios on pipelines are typically justified by I.C.C. requirements for through- commitments over the economic life of facilities and by the assured rate of re- built into pipeline tariffs. (Alaska's past forays into the arena of prospect- profits on TAPS have, from time to time, caused some nervousness over eventual ns on this pipeline investment.) Tanker financing is following the industry of off-balance-sheet debt in the form of lease commitments for life of vessel.

As noted, Sohio's cumulative capital requirements for TAPS (including con- tion interest but excluding property taxes) in the 1969-1977 period will total 0 million, of which 85% or $2,346 million will be supplied by debt and 15% or million by equity capital. Advances by the parent to Sohio Pipe Line Company quity capital have thus far amounted to $150 million of the $414 million total rement for equity capital. To date, Sohio has raised $1,724 million in medium long-term debt.** The company also has available a revolving bank credit (con- ible into a term loan) of $600 million. Thus, total debt financing for TAPS al- arranged is almost sufficient to cover TAPS' debt needs through 1977. Other rate uses of funds in the remaining 1975-77 pre-production period could amount ,404 million of which $1,065 or 76% would represent expenditures for North exploration/development and Alaskan taxes, $210 million or 15% for other cor- te capital expenditures (mainly in the lower 48 states), and the remaining $129 ion or 9% for dividends and scheduled debt repayment.

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assume that full-year 1977 financial needs have to be met prior to mid-year artup of TAPS.

date, Sohio's term debt for TAPS has been raised mainly through Sohio/BP Trans aska Pipeline Finance Inc. (Sohio Pipe Line Co., 67.8%; BP Pipeline Inc. 32.3%) d includes the following issues: December 4, 1974, $250 million in 9 3/4% deben- res due 1999; January 29, 1975, $250 million of 8 5/8% notes due 1983; July 1975, ,750 million of privately-placed 10 5/8% notes due in 1993 and 1998. In March 76, Sohio offered $200 million of notes due October 1, 1977. The funds may be d for North Slope facilities other than TAPS.

STANDARD OF OHIO

TAPS AND OTHER FINANCING: ADDITIONAL PRE-PRODUCTION FUNDING REQUIREMENTS

(Millions of Dollars)

	TAPS Capital Requirement, 1976-1977	$2,760
	TAPS Equity Requirement	$ 414
	Less: Advances by Parent to Sohio Pipeline	150
(1)	TAPS Equity Requirement less Financing to date	$ 264
(2)	TAPS Debt	$2,346
	TAPS Debt Financing	
	12/4/74 Sohio/BP $250 million 9 3/4% debentures due 1999	$ 169
	1/29/75 Sohio/BP $250 million 8 5/8% notes due 1983	169
	7/75 Sohio/BP $1,750 million 10 5/8% notes due 1993 and 1998	1,186
	Revolving Bank Credit	600
	3/76 Sohio $200 million 7.1% notes due 1/1/77[a]	200
(3)	TAPS Debt Financing to date	$2,324
(4)	(2)-(3) TAPS Debt Requirement less Financing to date	$ 22
	Other Corporate Uses of Funds 1976-1977: (ex TAPS and tankers)	
	North Slope	$1,065
	Other Capital Expenditures	210
	Debt Repayment	29
	Dividends	100
(5)	Total Other Uses of Funds	$1,404
	Other Sources of Funds, 1976-1977:	
	Corporate Cash Flow	$ 479
	Bank Credit, payable from crude proceeds	300
	10/2/75 Issuance of 2 million shares of common stock	136
	Advances on Coal ($96 million) and Uranium Development ($16 million)	112
	3/76 $50 million 7.6% notes due 4/1/79, and $75 million 8% notes due 4/1/81, both for payment of Alaskan reserves tax for 1976	125
(6)	Total Other Sources of Funds	$1,152
(7)	(1+4+5-6) Additional Financing Requirements, 1976-1977	$ 538

a. We assume the entire amount ($200 million) will be spent on TAPS.

Other sources of funds--including funds from operations ($479 million), issuance of common stock ($136 million), a bank credit repayable from proceeds on North lope crude ($300 million), advances on coal and uranium development ($112 million), nd sale of notes for 1976 payment of Alaskan reserves taxes ($125 million)--may total 1,152 million in the years 1976-77. Remaining financing requirements before start-up pproximate $538 million.

Sohio's options for financing the additional $538 million range widely. They nclude additional debt (public or private), equity financing, advance sales of crude everal modes are available), elimination of the dividend, even sale of an interest its equity in TAPS. Sohio could issue additional debt except as constrained by ctures attaching to existing debt, since the real collateral behind its Alaskanlated debt is the company's Prudhoe reserves, nothing else.* Obviously, Sohio's avy reliance on debt is contingent upon a rapid build up of its cash flow from rth Slope production, promising fairly prompt correction of the debt/equity imbalce. If North Slope crude were to sell for $11 a barrel on the West Coast (and if hio were to raise debt to cover the whole of its remaining financial requirements rough 1977), Sohio's cumulative cash flow from the first four years of its North pe operations would be sufficient to retire the company's entire outstanding debt projected for the close of 1977.

STANDARD OF OHIO

PROSPECTIVE DEBT/CAPITAL RATIOS, END 1977

(In Per Cent)

-1975	57%[a]
-1977 If 1976-77 Requirements Financed by Debt	60%[b]

Sohio's debt-to-capital ratio approximates 60% if deferred revenue (obligations) were included.

Sohio's debt-to-capital ratio would approach 63% if deferred revenue (obligations) were included.

io's leeway under those strictures for raising additional debt or for sale of rves in the ground would be more than ample even if current cost estimates were scalate substantially or were pre-production expenditures to balloon owing to y in completion of North Slope facilities.

his report was nearing completion, Sohio announced plans to issue $250 million ohio Pipe Line Co. debentures due 2001.

While from Sohio's point of view the cost of additional debt might be regarded as high by conventional standards relative to the cost of an equity financing, it is understandable why Sohio is postponing a major common stock offering. (Last year's equity issue was modest, given the scale of Sohio's capital needs.) Besides the variety of other options available for raising capital, an equity financing of almost 7.7 million shares at the recent price of the common would be needed to raise the entire remaining $538 million in external financing requirements for 1976-77. (Sohio must also consider BP's financial condition in issuing common stock since BP is entitled to purchase 54% of new stock offerings by Sohio.) Undoubtedly, Sohio is looking forward to the day when the price of its stock more adequately reflects the company's earnings possibilities.

In order to avoid both additional debt and a large equity financing, Sohio could resort to advance crude sales--its ace in the hole. To raise $538 million from advance crude sales, Sohio might have to convey roughly 110 million barrels of crude, or a little over 2.5% of its net proved reserves of liquids in the main field at Prudhoe Bay.

STANDARD OIL OF OHIO

POSSIBLE IMPACT OF TAPS DELAY ON FINANCING REQUIREMENTS*

(Millions of Dollars)

Capital Costs[a]	$ 60
Construction Interest on TAPS	235
Property Taxes	80
One-half of 1978 Spending[b]	190
	$565

* One-year delay.

a. Speculative.

b. Excludes expenditures on lower-48 pipeline.

On our reckoning, a full year's delay in startup could add $565 million to Sohio's remaining pre-production financing requirements, raising the total to $1,100 million. This lofty level of external cash needs would still be tolerable, prospective debt ratios considered, provided that a plausibly assured start-up date were then foreseeable.

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STANDARD OIL OF OHIO

NORTH SLOPE CASH FLOW AND POSSIBLE CAPITAL EXPENDITURES, 1978 - 1983

(Millions of Dollars)

	1978	1979	1980	1981	1982	1983
'Reserves Constraint" Case						
ash Flow[a]	897	1,061	1,005	1,022	980	991
ossible Capital Outlays	382	155	130	425	425	130
Main Field/TAPS/Tankers	382	155	130	130	130	130
Gas Development	...	...	...	295	295	...
'roduction Potential" Case						
sh Flow[a]	878	1,036	995	1,100	1,119	1,138
ssible Capital Outlays	507	280	370	1,005	965	670
Main Field/TAPS/Tankers	382	155	245	130	130	130
Lower-48 Pipeline	85	85	85	...	...	...
Lisburne/Kuparuk	40	40	40	40	...	...
Tertiary Recovery	...	...	...	540	540	540
Gas Developement	...	...	...	295	295	...
arket Constraint" Case						
h Flow[a]	881	896	810	963	919	924
sible Capital Outlays	382	195	170	465	465	130
Main Field/TAPS/Tankers	382	155	130	130	130	130
Lisburne/Kuparuk	...	40	40	40	40	...
Gas Development	...	...	...	295	295	...

Cash flow includes investment tax credits for the period 1978-1981 and reimbursement of Alaskan reserves taxes in 1978 and 1979. Earnings included in cash flow assume $11.00-per-barrel crude price and current tax laws.

AGO 531599

SCOMM

#12:14

ALASKA
STATE LEGISLATURE

MEMORANDUM

October 6, 1975

TO: Senator John Huber, Chairman
Special Committee on Taxation and Revenue

FROM: Franklin D. Fleeks
Committee Counsel

SUBJECT: Alaska Mineral Severance Tax, SB 294.

This memo is a summary of what has happened up to this date on SB 294. It is submitted for your information.

Review of the letters submitted and testimony at the hearing held on May 9, 1975, reveals that mining industry representatives, municipal utility officials, ancillary industry representatives, and interested individuals were unanimously opposed to the tax. The only testimony in favor of the tax was from the Department of Revenue.

The Department of Revenue Position

The Department of Revenue representatives stated that there is a severance tax on all of the state's renewable and non-renewable resources, oil and gas, timber, fishing, etc., except the "hard" mineral industry. The industry, at present, is taxed through a mining license tax, which is a tax on net income. From Commissioner Gallagher's testimony, the hard mineral industry grossed $62,000,000 for the 1974 fiscal year. The sources were as follows:

Sand and Gravel	$42,000,000
Coal	14,000,000
Other	6,000,000
Total	$62,000,000

From the approximately 200 licenses issued only two paid tax. One from the coal industry and one from the platinum industry. The amount collected brought the state $30,000 in revenue. The mining license tax is considered ineffective.

The present law is an additional net income tax. The Department considers it a tax on efficient procedures. Their position is that if a graduated severance tax is imposed it will fall on all producers of hard minerals in the State except those who sever less that $100,000 worth of minerals in a year. SB 294 would serve to tax a non-renewable resource, extract revenue from those producers who ship out-of-state or to foreign countries, provide easier administration, and would provide additional revenues from a source that other taxes may not be able to touch. Instead of $30,000 the anticipated revenue is $3,500,000.

SB 294 is considered prospective because of the low level of hard mineral activity in the State. Passage would allow the hard mineral industry to plan rationally its tax cost if further development takes place.

In answer to criticism that the bill was like the British Columbia Royalty tax, the Department of Revenue stated the following. The B.C. bill is a two step royalty linked to international price for the refined mineral and a Canadian wholesale price index. The royalty is in addition to Federal and provincial taxes and cannot be taken as a deduction in computing the taxes. The proposed mineral severance tax would be deductable on Federal and State Income Tax returns, the effect being that the tax would be paid half by the Federal and State governments and half by the taxpayer.

In talking to John Messenger, Assistant Attorney General, it was sensed that it is still the intent of the Department to go forward with the bill. Attempts will be made to make it more palatable.

Mining Industry Position

From testimony and the letters the industry's position is that passage of SB 294 will discourage current and future exploration for minerals. They consider the mineral severance tax a gross receipts tax and as such it is inherently unfair. They also stated that because the proposed tax would add another cost to the already heavy burden of exploring and developing minerals in Alaska, only those prospects having the greatest potential will be exploited. Marginal deposits would be left untouched.

Ancillary Industry Position

Testimony was given by Jim Dotson of the Alaska Air Carriers Association. He represented the view of the air taxi and air charter firms in the State. A large amount of the revenue of his members is derived from providing support to survey teams, geological teams, and others doing the summer exploration work. He had been informed that just because SB 294 had been proposed, two large summer contracts for 1975 had been cancelled. His position was that passage of SB 294 would seriously reduce the air carriers' revenue with a consequent reduction in air service in the State.

Utilities Position

Letters were received from Fairbanks Municipal Utilities System and Golden Valley Electric Corporation, since they are two of the largest consumers of coal for electric generating purposes. Their position is that the proposed tax would be passed on to them and increase their operating costs. This in turn would lead to a rate increase for their customers.

Native Corporations Position

In our Anchorage staff meeting on September 24, 1975, Representative Anderson gave the Native Corporations' position. He stated that SB 294 would make it more difficult to go to the capital market to obtain funds for exploration and development. He also stated that the proposed bill had caused delays in current negotiations with financial institutions.

It should be noted that the Administration, by Governor Hammond's letter of May 8, 1975, states that further hearings would be held " . . in order to jointly develop a rational tax . . "

Listed below are the names of the companies and persons who wrote to the Committee.

Mineral Severance Tax Project

Digest of Letters

Date	Correspondent
4/25/75	Dr. Johl Morris
4/17/75	Perry, Knox, Kaufman Inc. M.A. Kaufman
4/30/75	Cominco American J.C. MacLean
4/11/75	Rodney A. Blokestad
4/10/75	U.S. Borax J.E. Stephens
4/18/75	Heflinger Mining & Equipment Company Carl F. Heflinger
4/12/75	Eagle Creek Lodge Don Bennett
4/8/75	GVEA R.L. Hufman
4/4/75	Alaska Miners Association - Fairbanks Branch Mark Ringstad
4/11/75	MUS Robert Hanson
5/5/75	John E. Clark
5/6/75	Ketchkian Pulp Company Edward W. Borger, Sr.
5/6/75	Alaska Gold Company W.A. Glovinovich
5/19/75	C.C. Hawley & Association W.E. Shoemaker

460 Lovella Way
Sacramento CA 95819
26 October 1975

Senator John Huber
Special Committee on Taxation and Revenue
Pouch V
Juneau Alaska 99811

Dear John:

It was so very nice that you and Francis were able to visit us the other night, although I am sorry for both of your sakes that the occasion was so demanding physically, and sorry for all of us that it was so brief.

This letter's intent is to tell you something about the Nevada-type of tax on mineral rights (or leasehold interest, or whatever you want to call it) and give an indication of what it might mean relative to Prudhoe Bay. Here is the critical aspect of this sort of tax in contrast to the income tax: the Nevada system levies the tax <u>on the income to the property</u>, whereas an income tax is a tax <u>on the income to the person</u> (either individual or corporation). Thus, there is none of this jiggery-pokery about the geographic point at which income is realized. It is realized at the property.

Nevada has a successful 90-year history of administering this tax, which is in lieu of property taxes (Nevada has no income tax or severance tax). The tax is simple to administer, and it achieves equity because it is based on ability to pay. I should add that Nevada has a property tax on equipment, just as Alaska has, but it has no property tax on mineral rights.

Let's take a quick look at the approximate tax base that Prudhoe Bay will generate in its first year of production. You may recall that I testified in April of this year that Prudhoe Bay then had a value of about $10.3 billion; I estimated this value by escalating the price of oil and otherwise updating my 1973 appraisal made for the North Slope Borough. Employing the same escalation of price, and also escalating expenses, I estimate that the 1977-78 net income to mineral rights will be

<u>$2,259,000,000</u>.

Incidentally, I did not include $203 million that would otherwise be levied in severance taxes, for two reasons. One is that the severance tax complicates the issue of net income to mineral rights, and the other reason, which follows on the first, is that I do not believe that the severance tax should be levied if the net income tax to M.R. is used. It muddies the waters relative to tax equity.

The tax on net income to M.R. permits the retention of your present ad valorem property tax on equipment. The way this is done is to allow an expense against income that is an amortization charge on all the equipment. Thus, the value of the equipment is removed from the net income tax base.

There it is in a nutshell: a prospective $2 billion tax base consisting of the net income to properties, producing a tax to be paid in lieu of either severance, regular income, or ad valorem property taxes. Of course, the state's royalty income would also be received, and would be a charge against income in computing the net income to M.R.

If you would like me to do a detailed job on this for you, I will (1) write a report containing tax comparisons and prospective tax bases, (2) compose forms that will be required for administration, (3) suggest the staff required for the job (it will be remarkably small), and (4) testify on the issue. Of course, I would also be happy to work for you along other lines, such as the issues encountered this last spring. If you are interested in considering a net income tax to M.R. on mines as well as oil and gas fields, I can write a parallel report on that topic.

By the way, my work for Nevada was highly successful, in that the legislature adopted all of my major recommendations. If you want to check on this, you might write James Anderson, Chief, Division of Assessment Standards, Capital Plaza, 1100 East Williams, Carson City, Nevada 89701. He is in charge of implementing Nevada' revised program

And finally: as I told you when you were here, I will be out of the country all of December.

Oh, here's another "finally": I just got a letter from Sterling Gallagher inviting me to a meeting in Anchorage on November 6 on the subject of "Mining Tax Policy." Besides the fact that I will be giving a talk that day to the California Manufacturers Association in Newport Beach, I couldn't come to Anchorage merely on that invitation. I had earlier corresponded with Gallagner aoout doing some research for his Department on the above subject, but of course it was as a consultant and not merely as an individual visiting Alaska. Thought you might like to know.

Sincerely

Bob

Robert H. Paschall
Consulting Valuation Geologist
and Engineer

AGO 531605