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968

severance tax. In short, the subsidy is not available to fields like Cook Inlet, where no severance tax is currently paid.

While Weeks' example was restricted to one hypothetical new well at Kuparuk, and may or may not reflect what is currently happening at Kuparuk or Prudhoe Bay, recent econometric modeling studies by the Department of Revenue estimate the Prudhoe Bay drilling subsidy in the range of $19 million in FY 88, and about $40 million in FY 89. The model indicates that a tax break that would have totalled about $240 million during FY88-89 has been increased to approximately $300 million by the additional drilling.

Not only is this subsidy going to be costly to Alaska, it is an extraordinarily inefficient way to create jobs or additional oil production.[7] The overall effect of this subsidy may be that, by accelerating drilling that would have occurred later anyway, it robs jobs and economic stability from the future for the sake of higher production and profits in the short term.

ELF and Jobs

Alaskans are concerned about the effects a change in the ELF may have on jobs. Oil industry proponents have said that the recent increase in drilling has created 2,400 new jobs — 800 drilling jobs and 1,600 additional jobs. They implied that those jobs would be lost if the proposed new ELF is adopted.

[7] A March 1988 analysis by the Dept. of Revenue implies that each barrel gained through the subsidy through the year 2000 costs the state $175 in foregone revenue.

The figure of 2,400 new jobs (or even 800) bears no resemblance to the reality reflected in Department of Labor employment figures taken from employer records. Total oil and gas employment on the North Slope during the fourth quarter of 1987 was 3,994 jobs, down by 122 jobs from a year earlier. Drilling employment at the end of 1987 was actually about 50 jobs less than at the end of 1986. Some modest employment increase may occur this spring, but nothing on the scale of 800 new jobs is conceivable, given that 1987 year-end North Slope drilling employment was only around 500 with 12 rigs operating.[8] The Department of Natural Resources estimates the rig count will climb to 14 on the North Slope this spring. The resulting rise in employment might be 80 to 100. Each rig employs an estimated 40 to 50 workers, depending on the type of drilling.

In total, the oil industry generates about 8,500 jobs in Alaska, about 4 percent of Alaska's work force — and only about 6 percent of the entire private sector work force. Unfortunately, many of those employed by the oil industry are not Alaska residents.

The drilling companies now operating on the North Slope employ about 28 percent non-Alaskans. The hiring record of the major drilling firms ranges from 57 percent non-residents to 15.4 percent non-residents. The hiring of non-residents by other oil industry segments (exploration and services) also runs about 28 percent , with the exception of the production/ management sector, which has trimmed its non-Alaskan hiring to about 11 percent.[9] These statistics make for one of the poorest resident hire

[8] Statewide oil industry employment, however, was up by about 200 jobs over this period. For more detail on recent employment trends, see Alaska Economic Trends, Alaska Department of Labor, October 1987.

[9] The Department of Labor developed the statistics by cross-checking employment records with Permanent Fund dividend records.

records in the state, according to the Department of Labor.

Industry-wide, these non-Alaskans have total earnings of about $80 million, which is the highest amount of wages paid by any industry to non-residents. Much of this non-resident income, of course, does not circulate in or benefit the Alaska economy.

As oil fields mature, labor required to produce a given amount of oil tends to increase. Over the long run, oil and gas employment is likely to increase in Alaska due to these technical factors, regardless of the state's action on the ELF bill. A huge tax increase might discourage additional field development, but economic studies by the state and others indicate that the economic effects of the ELF change will be marginal.[10] Also, correcting the misapplication of the current ELF to Prudhoe Bay and Kuparuk, while improving incentives for smaller fields, is not likely to adversely affect future field developments. From an Alaskan perspective, given the record of the oil industry to date, a real concern will continue to be whether the jobs generated by additional oil development will be filled by residents or non-residents.

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[10] "[T]he economic limit factor in Alaska's severance tax...has limited ability and high revenue cost for conserving oil and gas from producing fields," according to University of Alaska researchers led by Mathew Berman in Alaska Petroleum Revenues: The Influence of Federal Policy, Institute of Social and Economic Research, October 1984, pp. xxvii. See also, "Severance Tax Impact Often Misinterpreted," by John Lohrenz, in Oil and Gas Journal, June 18, 1984, pp. 133-137; "Analysis of ELF Alternatives," by Charles Logsdon, Alaska Dept. of Revenue, October 14, 1986; and "A Model to Assess Economic Feasibility and Optimum Production Volume for North Slope Fields," by R. Marks and J. W. Moore (both with the Alaska Dept. of Revenue) in Journal of Petroleum Technology, August 1987, pp. 943-54.

Profitability

Does the oil industry in Alaska need a tax break now to continue production at Prudhoe Bay and Kuparuk? This question is at the heart of the current oil tax discussions.

Companies with major oil interests in Alaska are all publicly traded on the stock market. Alaska industry operations have attracted the interest of numerous trade publications, investment advisory services, and occasionally academic and government researchers. All the studies indicate that Prudhoe Bay and Kuparuk are extraordinarily profitable oil fields.[11]

According to a recent study, published February 1, 1988, in *Petroleum Intelligence Weekly (PIW),* a respected trade journal, oil companies are currently making after-tax profits of $6.2 million per day from North Slope operations. State and local revenue from North Slope oil, by comparison, is estimated by *PIW* at $4.7 million per day. (The *PIW* article and the state's analysis of the *PIW* figures are found in Appendix B.)

Under the new ELF, oil companies' profits would continue to be larger than state revenue, though not by as big a margin. Industry profits would decline to $5.6 million daily, after all expenses, taxes and royalties are paid. As Figure 1 shows, the ELF will have only a small impact on the relative shares of revenue going to the state and the producers.

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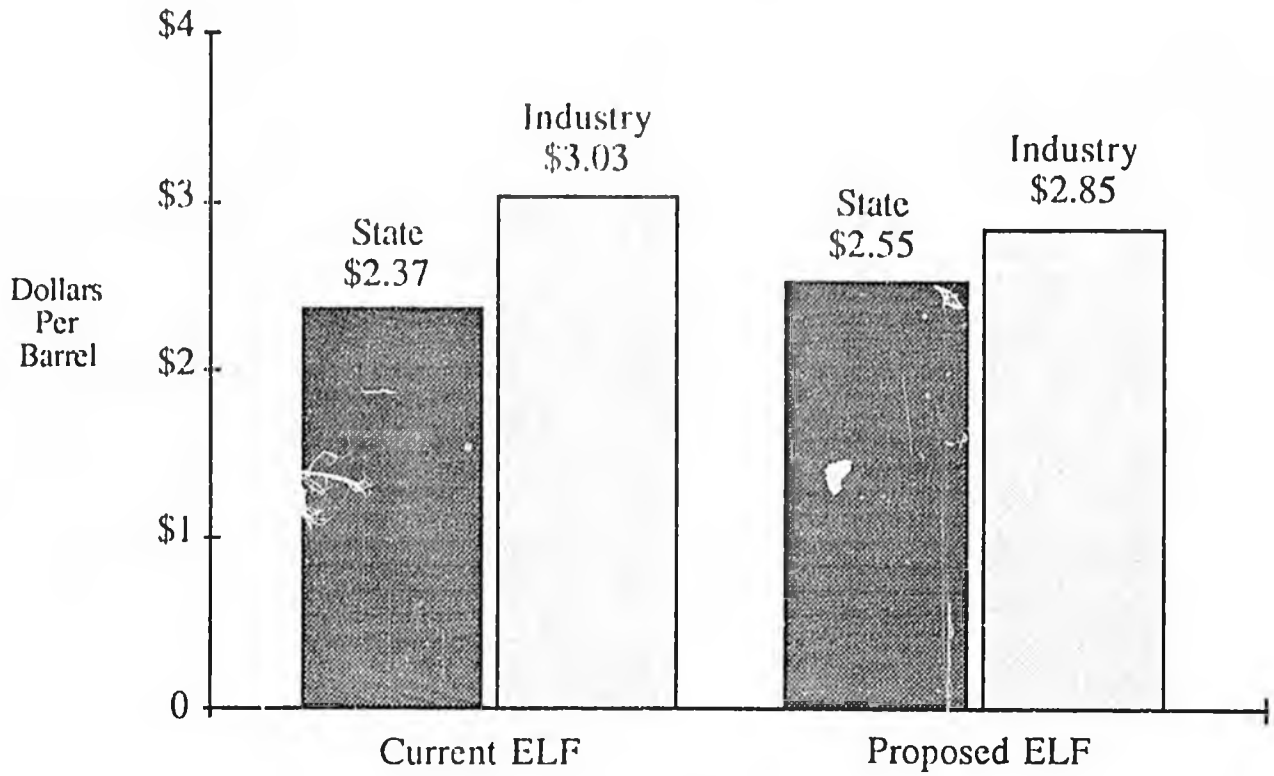
[11] In addition to the *PIW* analysis described below, the following studies have been released in 1988: "Alaska's Oil Promise Remains Strong," in International Petroleum Finance, March 18, 1988, p. 8; "Alaskan Resource Wealth -- The Inestimable Bounty" in Atlantic Richfield Company -- Restructured and Resourceful, Part II, by Salomon Brothers (Bernard Picchi, author), March 31, 1988, p. 3-4; "$30 a Barrel Profits in an $18 World," in Forbes, March 21, 1988, pp. 110-114; and "Income and Investment Flows From Alaska Oil and Gas Producing Activities," by Edward Deakin, in Joint Special Committee on Tax Policy, Final Report, Alaska State Legislature, January 1988.

Figure 1

State and Industry Shares

(Dollars Per Barrel)



Shares under current ELF are from *Petroleum Intelligence Weekly* Feb. 1, 1988; shares under the proposed ELF are by the Division of Policy, April 11, 1987.

Data on the cash flowing to and from North Slope operations suggest that since 1978 in Alaska, only a fraction of the funds generated by North Slope oil have been reinvested in Alaska. According to the *PIW* figures, the companies' current cash flow (profits and depreciation) from the North Slope comes to $10.6 million per day.[12] The Division of Policy estimates that the rate of oil industry reinvestment in Alaska is $1.9 million per day. Thus, as shown in Figure 2, the oil industry today is taking $8 Outside for every $2 it reinvests in Alaska.

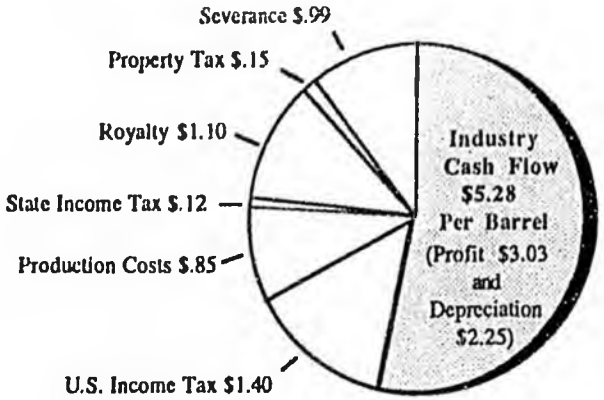
This "takeout" from Alaska's North Slope production has made the major producers in Alaska uniquely successful companies. A March 21,

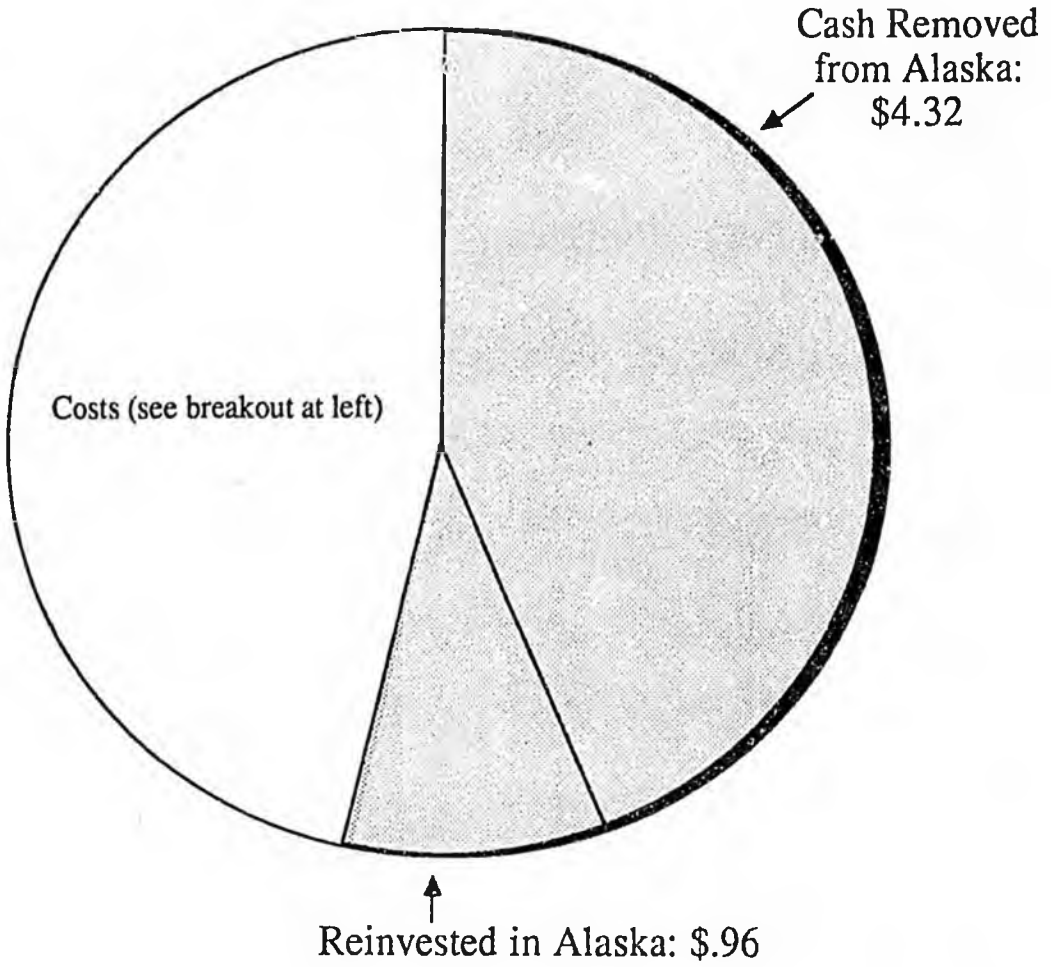
[12] The *PIW* figures do not include depreciation on the pipeline, so the cash flow to producers from North Slope operations is understated.

Figure 2

The Economics of North Slope Oil

(Dollars Per Barrel)





Source: Division of Policy, based on *Petroleum Intelligence Weekly* February 1, 1988.

Office of the Governor
Division of Policy
4/12/88

1988 *Forbes* article examined ARCO's phenomenal success: "...a return on equity of 23 percent, just about the best in the industry and roughly twice the industry average." Astute corporate management, company restructuring, and its Alaska resources let ARCO " claim the highest per-barrel profit of any marketer on the West Coast." Key to ARCO's current strength, said *Forbes*, "is its commanding position in the U.S. largest oil reserve, the Alaskan North Slope, from which it derived 68 percent of its production last year." With $3 billion in cash reserves, ARCO is actively investing its Alaskan profits elsewhere.

A report by Salomon Brothers, March 31, 1988, similarly calls ARCO "the premier equity investment in the domestic oil industry." The report goes on to say, "Arco's Alaskan resource base is without parallel in the industry in terms of its size alone. Arco's net share of the original oil in place in its Alaskan oil fields, 20 billion barrels, is **equal to 75 percent of the proved oil reserves of the rest of the country."** Top ARCO management also cited its Alaska holdings as key to the company's profitability: "ARCO Alaska's low-cost producing ability provides the base for ARCO's West Coast downstream infrastructure: its integrated transportation and refining and marketing assets." [13]

Production

Oil development patterns are not easily predictable so forecasts of future production should be interpreted cautiously. Department of Revenue modeling studies nevertheless suggest that while the new ELF

[13] "Alaska Operations," Harold Heinze, President, ARCO Alaska, Inc., Oil Industry Analysts Meeting, March 31, 1987.

could initially cause lower production, any impact would be small. The probabilities are that the new ELF will decrease North Slope output by a cumulative 1 million barrels during the FY 1988-93 period — equal to about 12 hours of flow through the TAPS pipeline. The cumulative production loss through 2005 is estimated at about 21 million barrels, or about 10 days of North Slope production. Losses taper off in later years but become gains sometime after 2020, when the new ELF increases incentives for production in the later stages of oil field life.

The ELF is a minor factor in industry decisions to pursue Prudhoe Bay development. What matters most is oil prices. For example, a spokesperson for ARCO, commenting on that company's plans to drill five Prudhoe Bay development wells in September, 1987, stated," resuming production drilling in Prudhoe i. ood news and strictly the result of higher oil prices."[14] A March 31, 1988, stock research report notes, "West Sak field production could start in 1992, because the field is profitable at oil prices of $15-20 per barrel."[15]

How does increased production benefit Alaska? Nearly all manufacturing and assembly of equipment used in the oil industry is done outside Alaska so economic impacts from that sector are small, according to Department of Labor economists. The ARCO newsletter of January 1, 1988, states, "Between 1980 and 1986, North Slope development accounted for approximately $10.5 billion in hard goods alone, according to ARCO Alaska, Inc., Standard Alaska Production Company and Conoco." The newsletter indicates one-eighth of that amount ($1.35 billion) was spent in

[14] Alaska Report, p. 1, 7/22/87.

[15] Atlantic Richfield Company---Restructured and Resourceful, Part II, by Salomon Brothers, March 31, 1988, p.1.

Alaska, with the remainder going Outside, with Texas and California the largest beneficiaries.[16] Employment opportunities, however limited, and revenues to the state, are the most readily discernible benefits to Alaska.

Comparing Taxes

Though the existing tax at Prudhoe Bay is 12.3 percent, the *nominal* rate at Prudhoe Bay, without the ELF, is 15 percent. But no field in Alaska pays the full tax rate. Furthermore, the severance tax rate contrasts with the low corporate income tax rate. [17]

Each state designs its severance tax structure for its particular conditions in that jurisdiction. The range of profitability among fields in Alaska is very different from any other state. In none of the other states is there an oil field even close to the size of Prudhoe Bay. But because the fields in other states are much nearer to oil markets, the wellhead price of a barrel is much lower in Alaska. Unlike other states, Alaska gains little

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[16] On Top of ANWR. ARCO Alaska, Inc., January 1, 1988.

[17] Here is how Alaska's effective severance tax rate compares to other major oil-producing states on a percentage basis:

State	Severance Tax as a Percent of Value
Alaska (Prudhoe proposed)	14.8 %
Wyoming (state & average local)	13.0 %
Louisiana	12.5 %
Alaska (Prudhoe existing)	12.3 %
Alaska (Kuparuk proposed)	11.9 %
Alaska (Kuparuk existing)	8.0 %
Oklahoma	7.0 %
Texas	4.6 %
New Mexico	3.8 %

This chart is based on average effective severance tax rates in FY 1988. Under current law the Prudhoe Bay rate will decline to 11.9 percent in FY 1989.

from the manufacturing and retail sales of most of its petroleum resources — although the producers realize additional profits from transporting, refining, and selling North Slope oil. Differences like these make simplistic comparisons regarding which state has the "highest" or "lowest" severance tax of limited use.

On a dollars-per-barrel basis, for example, Alaska's tax rate is among the lowest of all the producing states.[18] If the oil fields in these states were somehow transported to Alaska, all would find their severance taxes reduced or eliminated. The reason for this apparent paradox is that all are so much smaller than Prudhoe Bay or Kuparuk. Prudhoe Bay wells, according to Standard Alaska, are producing an average 2,300 barrels per day. The average oil well in Texas, in contrast, produces 145 barrels per day. A well producing at that rate in Alaska, like most oil wells in Cook Inlet, would pay no severance tax whatever under either the existing or proposed ELF. Similarly, virtually all the fields Outside that would pay tax under the current ELF would pay less tax under the new ELF.

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State	Approximate Severance Tax Per Barrel
Wyoming (state & average local)	$2.02
Louisiana	$1.94
Alaska (Prudhoe proposed)	$1.26
Oklahoma	$1.08
Alaska (Prudhoe existing)	$1.05
Alaska (Kuparuk proposed)	$1.04
Texas	$0.71
Alaska (Kuparuk existing)	$0.62
Alaska (Cook Inlet)	$0.00

Estimates for other states are derived from the effective tax rates of other states at a well-head price of $15.50 (Gulf Coast).

The "Commitment"

The ELF issue in 1988 is the legacy of a 1981 tax bill that passed in an extraordinary hurry. The issue of how to respond to the North Slope oil producers' legal challenge to separate accounting was the focus of attention for much of the 1981 legislative session. However, the proposal that modified the ELF was first unveiled to a free conference committee on June 22, 1981. Two days later, it passed both houses and was on its way to the governor. There was little time to study the bill; moreover, the fiscal note prepared by then-Commissioner Williams included no projections beyond FY 1985. The confusion concerning what legislators and Governor Hammond meant when they adopted the 1981 legislation is not surprising.

A 1981 post-session analysis by the Legislative Finance Division showed that the ELF provision would cause state revenue to fall sharply in FY 1988. When Governor Hammond reluctantly signed the bill, he expressed "full confidence in the ability of the legislature to deal at that time" with any adverse revenue consequences.

Governor Hammond insisted that the oil tax changes adopted in 1981 not reduce the state's share below the 30 percent that was thought to be the rough percentage level of the state's share *at that time*. Hammond sought to insure that the tax changes would be "revenue neutral;" i.e., that the changes would leave state oil revenue largely unaffected. It is now clear that the changes adopted in that bill were far from neutral as to state revenue: between fiscal 1982-87 total tax collections were reduced by over $1 billion compared with what would have been collected had the changes not been made.

As shown in Appendix C, the 1981 record contains statements by Hammond, then-Rep. Rick Halford, Commissioner Williams and others addressing the future need to revise the 1981 scheme by 1987 or 1988. But the written record of the 1981 deliberations provides no evidence of any legal, moral, or political commitment by state officials to limit the state's appropriate share of future oil income. Additionally, company officials testified to the Legislature that the state's share should equal the industry share.

Revenue Effects

As originally introduced by the Governor in 1987, the ELF legislation would have kept the ELF from applying to Prudhoe Bay for an additional five years. The measure that passed the House and now awaits action in the Senate takes a more comprehensive approach: the new ELF applies at Prudhoe Bay, but the formula for calculating the new ELF includes consideration of field productivity in addition to well productivity. The new formula gives Prudhoe Bay a much smaller tax break now, but a larger tax break later when the giant field finally reaches its marginal years of production. Tax revenue from nearby Kuparuk, the second largest producing field in the United States, would also increase. All other producing fields would either pay no tax at all or receive a bigger tax break than they get under the current ELF.

The net effect of the new ELF, using the Department of Revenue's March, 1988 "mid-case" assumptions, would be $150 million in additional state revenue in FY 1988, and $152 million in FY 1989. To put this amount

in perspective, $150 million is about the amount of the combined annual general fund budgets of the departments of Fish and Game, Labor, Commerce, Natural Resources, Revenue and Environmental Conservation, and about one-quarter of the amount the state spends each year on elementary and secondary education. As the table below shows, the revenue gain from the new ELF depends, in part, on the level of oil prices.[19]

Average Oil Prices[20]	Incremental FY 89 Revenue From the ELF Bill, CSHB 164 (Fin) am
$11.00/B	$114 million
$12.00/B	$125 million
$13.00/B	$136 million
$14.00/B	$146 million
$15.00/B	$157 million
$16.00/B	$167 million

According to Department of Revenue projections, the dollar gain from the new formula would peak in FY 91 at $223 million, and then gradually diminish as Prudhoe Bay production declines. The yearly dollar gain from the new ELF will vary with oil prices and total oil production. Over the next six years, the percentage loss to the state's oil revenue from

[19] Other factors would also affect the fiscal effect of the proposed legislation. The table is based on the "mid-case" assumptions in the current Department of Revenue forecast.

[20] Weighted average of U.S. West Coast and Gulf Coast selling prices for Alaska North Slope crude.

the current ELF will increase from approximately 8 percent this year to nearly 14 percent in fiscal year 1993. (Complete long-run projections are contained in the ELF legislation fiscal note, in Appendix A .)

Budget Stability and the Economy

In opposing the ELF legislation, one senator argues that "the solution to Alaska's economic problems is not increasing taxes to fuel more government spending," but instead to just cut state spending.

How big a cut would be required to balance the budget? With only weeks to go in the legislative session, Alaska faces a revenue shortfall of about $150 million to $400 million, depending on the optimism of the forecaster. Theoretically, the budget could be balanced by cutting hundreds of millions of dollars from spending, but this approach is hard to take seriously in light of the vital impact of state spending on a recovering economy. In fact, the legislature has already recognized the role of state spending in the economy's health in its early passage of the "jobs" bill.

Budget cuts over the last three years have brought per capita real spending down — dramatically. The deepest recession the state has ever experienced was one consequence. Now — as that recession is ending — is not the time for extracting hundreds of millions of dollars from Alaska's economy.

With state spending now well below its 1979 level and the economy starting its recovery, Governor Cowper has proposed a maintenance level budget. The House and Senate can reduce the budget shortfall by eliminating proposed expenditures. But, close to half the budget is pass-

through entitlement programs to local governments, schools, and individuals, politically difficult areas to cut. It appears the majority of Senators and Representatives do not believe this is the time for inflicting the stress of another multi-million dollar spending cut on the Alaska economy. Although reductions and reallocations will certainly occur, deep cuts are not a realistic possibility.

So what options are left? The use of the Railbelt Energy Fund has been proposed. But many Railbelt voters rebel against "their" money being spent to solve a statewide problem, and the construction industry opposes any non-construction use of the money.

Another option is to use the cash reserves (earnings reserve account) of the Permanent Fund. Using the reserves would reduce future dividends. However, the necessary appropriation could be a "loan" with a promised but problematical payback in the future. Combined, the Railbelt Energy Fund and the Permanent Fund earnings reserves are the state's cash reserves since last year the Budget Reserve Fund was emptied to help meet last year's revenue shortfall. Without these funds as backstops, Alaska is left with no emergency monies to meet another precipitous drop in oil prices.

Leaving aside the obvious difficulties inherent in the use of either the Railbelt Energy Fund or Permanent Fund earnings to fill the budget shortfall this year, there remains the issue of revenue stability. This issue deserves very serious consideration for two reasons. First, Alaskans desire and need public services. Second, there clearly exists a now-demonstrated tie between Alaska's revenue stability and Alaska's economic stability. [21]

[21] For evidence of the relationship of state budget stability to economic activity in Alaska, see "Can State Spending Speed Alaska's Recovery," by Professor Scott Goldsmith and Lee Gorsuch, Institute of Social and Economic Research, University of Alaska, December, 1987.

Both reserve sources are only stop-gap measures, providing one or two years of fiscal relief, at most. Neither fund provides an answer to the on-going loss of more than 8 percent of Alaska's oil revenues and the erosion of Alaska's fiscal strength year after year. The new ELF does. It's a long-term solution to what will otherwise be a long-term loss.

Finally, the legislature simply could pretend that there is no problem. Led by the Senate, the legislature gambled last year that oil price increases would cover the shortfall in the budget with extra revenue. It worked then, due in part to the unexpected receipt of some monies owed the state by the federal government. [22] The legislature could roll the dice again. The risk is that the extra revenue will not materialize and that the state will be unable to pay its bills. If oil prices don't rise, current cash flow projections show that the risk could become reality as early as February or March 1989.

Division of Policy

April, 1988

[22] The funds received were $160 million which had been held in escrow by the federal government pending resolution of the Dinkum Sands boundary dispute.

Appendix A

STATE OF ALASKA
1988 LEGISLATIVE SESSION

BILL VERSION: CSHB164 (fin) am
PUBLISH DATE: _____

FISCAL NOTE

REQUEST:

Revision Date: April 4, 1988
Title: An Act Relating to the Oil and Gas Properties Production Tax & Effective Date
Sponsor: Rules/Governor
Requestor: _____

Agency Affected: _____
BRU: _____
Components: _____

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING						
CAPITAL						
REVENUE	150,150	152.330	203,450	222,850	213,940	207,490

FUNDING: (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER						
TOTAL						

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

See Attached

Prepared by: Charles L. Logsdon
Division: Oil and Gas Audit
Phone: 277-5627
Date: April 4, 1988

Approved by Commissioner: _____
Agency: Revenue
Date: 4/4/1988

Distribution (by preparer):
Legislative Finance
Legislative Sponsor
Requestor
Office of Management and Budget
Impacted Agency(ies)

page ____ of ____

This bill would effectively increase the severance tax rate on fields producing greater than approximately 120,000 barrels per day. At the same time, fields producing less than this amount would be taxed at a lower rate. The relative increase or decrease would depend on the relative per well productivity of the field. The estimates contained in this fiscal note are based on the Department of Revenue March 1988 mid scenario assumptions about production, wells, and oil prices.

The attached tables illustrate the revenue and tax rate impact of the bill by North Slope oil field. The sensitivity of the tax revenues to change in oil prices is also illustrated.

FY 1989 PRICE/REVENUE SENSITIVITY OF CSHB164(fin) am
(Millions $)

	$10.00/bbl	11.00	12.00	13.00	14.00	15.00	16.00	17.00
Prudhoe	93.16	102.47	111.79	121.10	130.42	139.73	149.05	158.36
Kuparuk	21.54	23.69	25.84	28.00	30.15	32.30	34.46	36.61
Milne	0	0	0	0	0	0	0	0
Endicott	-6.49	-7.14	-7.79	-8.43	-9.08	-9.73	-10.38	-11.03
Lisburne	-3.72	-4.10	-4.47	-4.84	-5.21	-5.59	-5.96	-6.33
TOTAL	104.48	114.93	125.37	135.82	146.27	156.72	167.17	177.61

CHANGE IN REVENUE CSHB164
(Millions $)

YEAR	PRUDHOE	KUPARUK	MILNE	ENDI	LISB	W SAK	PT THOM	SEAL IS	NIAKUK	TOTAL
1988	130.03	30.30	0.00	-4.27	-5.93	0.00	0.00	0.00	0.00	150.15
1989	125.82	31.40	0.00	-9.46	-5.43	0.00	0.00	0.00	0.00	152.33
1990	172.12	39.56	0.00	-2.04	-6.19	0.00	0.00	0.00	0.00	203.45
1991	190.27	40.37	0.00	-2.25	-5.53	0.00	0.00	0.00	0.00	222.85
1992	183.74	39.61	0.00	-2.40	-7.01	0.00	0.00	0.00	0.00	213.94
1993	180.62	38.38	0.00	-5.24	-6.27	0.00	0.00	0.00	0.00	207.49
1994	178.59	36.55	0.00	-6.55	-6.74	0.00	0.00	0.00	0.00	199.74
1995	171.39	30.60	0.00	-7.41	-7.18	0.00	0.00	0.00	0.00	187.40
1996	162.83	22.19	0.00	-7.50	-7.83	0.00	0.00	0.00	0.00	169.69
1997	164.10	14.09	0.00	-7.32	-8.17	0.00	0.00	0.00	0.00	162.70
1998	157.08	6.98	0.00	-6.84	-8.44	0.00	0.00	0.00	0.00	148.78
1999	144.16	2.76	0.00	-4.29	-8.30	0.00	0.00	0.00	0.00	134.33
2000	137.86	1.22	0.00	-2.29	-8.44	0.00	0.00	0.00	0.00	128.35
2001	127.38	0.46	0.00	-0.61	-9.29	0.00	0.00	0.00	0.00	117.94
2002	118.80	0.08	0.00	0.00	-9.79	0.00	0.00	0.00	0.00	109.09
2003	122.08	0.06	0.00	0.00	-9.43	0.00	0.00	0.00	0.00	112.71
2004	116.55	0.04	0.00	0.00	-9.28	0.00	0.00	0.00	0.00	107.32
2005	103.90	0.03	0.00	0.00	-8.90	0.00	0.00	0.00	0.00	95.03
2006	91.47	0.00	0.00	0.00	-9.36	0.00	0.00	0.00	0.00	82.11
2007	80.19	0.00	0.00	0.00	-7.52	0.00	0.00	0.00	0.00	72.67
2008	69.43	0.00	0.00	0.00	-6.12	0.00	0.00	0.00	0.00	63.31
2009	61.76	0.00	0.00	0.00	-4.73	0.00	0.00	0.00	0.00	57.03
2010	55.85	0.00	0.00	0.00	-3.38	0.00	0.00	0.00	0.00	52.48

CHANGE IN SEVERANCE TAX RATE PERCENT OF VALUE CSHB164

YEAR	PRUDHOE	KUPARUK	MILNE	ENDI	LISB	W SAK	PT THOM	SEAL IS	NIAKUK
1988	0.0249	0.0391	0.0000	-0.0258	-0.0382	0.0000	0.0000	0.0000	0.0000
1989	0.0281	0.0448	0.0000	-0.0332	-0.0321	0.0000	0.0000	0.0000	0.0000
1990	0.0353	0.0481	0.0000	-0.0040	-0.0324	0.0000	0.0000	0.0000	0.0000
1991	0.0373	0.0513	0.0000	-0.0023	-0.0291	0.0000	0.0000	0.0000	0.0000
1992	0.0384	0.0539	0.0000	-0.0023	-0.0277	0.0000	0.0000	0.0000	0.0000
1993	0.0421	0.0550	0.0000	-0.0028	-0.0270	0.0000	0.0000	0.0000	0.0000
1994	0.0450	0.0545	0.0000	-0.0194	-0.0282	0.0000	0.0000	0.0000	0.0000
1995	0.0488	0.0491	0.0000	-0.0251	-0.0282	0.0000	0.0000	0.0000	0.0000
1996	0.0548	0.0405	0.0000	-0.0315	-0.0289	0.0000	0.0000	0.0000	0.0000
1997	0.0548	0.0334	0.0000	-0.0353	-0.0314	0.0000	0.0000	0.0000	0.0000
1998	0.0574	0.0171	0.0000	-0.0375	-0.0345	0.0000	0.0000	0.0000	0.0000
1999	0.0583	0.0083	0.0000	-0.0320	-0.0368	0.0000	0.0000	0.0000	0.0000
2000	0.0587	0.0042	0.0000	-0.0231	-0.0373	0.0000	0.0000	0.0000	0.0000
2001	0.0585	0.0017	0.0000	-0.0102	-0.0391	0.0000	0.0000	0.0000	0.0000
2002	0.0585	0.0001	0.0000	0.0000	-0.0413	0.0000	0.0000	0.0000	0.0000
2003	0.0589	0.0000	0.0000	0.0000	-0.0426	0.0000	0.0000	0.0000	0.0000
2004	0.0592	0.0000	0.0000	0.0000	-0.0433	0.0000	0.0000	0.0000	0.0000
2005	0.0598	0.0000	0.0000	0.0000	-0.0440	0.0000	0.0000	0.0000	0.0000
2006	0.0462	0.0000	0.0000	0.0000	-0.0475	0.0000	0.0000	0.0000	0.0000
2007	0.0409	0.0000	0.0000	0.0000	-0.0434	0.0000	0.0000	0.0000	0.0000
2008	0.0344	0.0000	0.0000	0.0000	-0.0411	0.0000	0.0000	0.0000	0.0000
2009	0.0339	0.0000	0.0000	0.0000	-0.0357	0.0000	0.0000	0.0000	0.0000
2010	0.0309	0.0000	0.0000	0.0000	-0.0314	0.0000	0.0000	0.0000	0.0000

APPENDIX B

ALASKA NORTH SLOPE ECONOMICS *

Weighted Average of West and Gulf Coast Sales as Reported in PIW

	REVENUE, COSTS &INCOME PER BARREL			
	1985	1986	1987	1988
Wellhead price/barrel	$16.72	$10.17	$7.54	$9.47
LESS:				
Royalty/barrel	$2.01	$0.73	$0.86	$1.10
Severance/barrel	$2.21	$0.87	$1.00	$0.99
Property tax/barrel	$0.21	$0.18	$0.16	$0.15
Producing cost/barrel	$0.90	$0.75	$0.80	$0.85
Depreciation/barrel	$1.53	$2.17	$2.21	$2.25
State income tax/barrel	$0.29	$0.06	$0.08	$0.12
US income tax/barrel	$4.54	$0.84	$0.89	$1.40
PLUS:				
Pipeline profit/barrel	$2.18	$0.64	$0.58	$0.43
EQUALS:				
Industry profit/barrel	$7.22	$1.56	$2.13	$3.03

	NET INCOME SHARES			
Shares in dollars per barrel				
Industry profits/barrel	$7.22	$1.56	$2.13	$3.03
State & local rev./barrel	$4.71	$1.84	$2.10	$2.37
Federal rev./barrel	$4.54	$0.84	$0.89	$1.40
Shares in billions of $ per year				
Industry profits/year	$5.004	$1.102	$1.530	$2.211
State & local revenue/year	$3.269	$1.294	$1.512	$1.728
Federal revenue/year	$3.148	$0.592	$0.640	$1.022
Shares in percent of total				
Industry profits	43.8%	36.9%	41.6%	44.6%
State & local revenue	28.6%	43.3%	41.1%	34.8%
Federal revenue	27.6%	19.8%	17.4%	20.6%

	ALASKA REINVESTMENT PERFORMANCE			
Reinvestment in billions $/year				
Cash flow (billions $/year)	$6.065	$2.630	$3.119	$3.853
Reinvestment (billions $/year)*	$0.860	$1.322	$0.650	$0.700
Reinvestment in $/barrel				
Cash flow per barrel	$3.75	$3.73	$4.34	$5.28
Reinvestment per barrel*	$1.24	$1.88	$0.90	$0.96
Percentage reinvested in Alaska	14%	50%	21%	18%

** Revenue, costs and income data from Petroleum Intelligence Weekly (attached); reinvestment performance estimated by the Division of Policy.*

See the following page for additional notes.

Division of Policy, 4/11/88

Notes to analysis of *PIW* data on North Slope economics:

1. PIW data for the first and second half of 1986 and 1987 were averaged using equal weights to produce the average annual values shown on the preceding page.

2. PIW values stated separately for U.S. West and Gulf coasts were combined to provide weighted average figures; the following weighting factors were used (West/Gulf): 1985-50%/50%; 1986-52.5%/47.5%; 1987-56.66%/46.67%; 1988-60%/40%.

3. Annual revenue figures assume production levels of 1.90 MMB/D, 1.93 MMB/D, 1.96 MMB/D, and 2.00 MMB/D in 1985-88 respectively.

4. Data for 1988 are extrapolated assuming costs and revenues continue at the per barrel levels reported in *PIW* for the first two months of 1988.

5. Reinvestment estimates for 1985-6 are from Income and Investment Flows From Alaska Oil and Gas Producing Activities, by Edward Deakin, May, 1987. Estimates for 1987-8 are Division of Policy estimates based on industry statements of current and planned project activity.

6. Cash flow is understated by an estimated $2.00 per barrel because depreciation on pipeline investments are not accounted for separately in the *PIW* data. (Pipeline tariffs are deducted before determining the wellhead price per barrel.)

Division of Policy
11 April 1988

FOUNDED 1961. Vol.XXVII No.5 February 1, 1988

PETROLEUM INTELLIGENCE WEEKLY®

Short-Haul Sales By Saudis Key To Overseas Stockbuild

Oil markets should be very careful in drawing grand conclusions about Saudi Arabia's oil policies on the basis of its latest foray to charter ships for moving crude oil into its overseas stockpile. The fact is that Saudi Arabia is in the process of placing a large chunk of stockpile crude with several of the Aramco partners on a delivered basis, and it chartered the tankers almost entirely to replenish those supplies, according to well informed PIW sources in shipping circles. The stockpile moves say more about Riyadh's wish to retain a basic presence as a short-haul crude supplier in the Caribbean and Europe (p5) than about its long-term goals or role within Opec (PIW Jan.25,p1). PIW confirms that the Saudis have lined up five ships to move 10-million barrels of oil into overseas storage in the coming weeks, plus at least one other vessel to supply non-Aramco clients like Ashland and Marathon. In the past, the Saudis have used the Western Hemisphere stockpile for occasional spot sales, and more routinely to supply term customers on a prompt basis.

By taking nearby crude from the stockpile now, the Aramco partners get the benefit of the oil in the heart of the winter season, rather than in late March or early April when oil loaded today in Saudi Arabia would arrive at Atlantic Basin destinations. The stockpile barrels are within the overall 1.4-million b/d of crude the partners obtained from the Saudis in January, and are expected to take in February. They do not represent any extra supply. Overall Saudi output volume is still below Opec quota in the 3.8- to 4-million b/d range (excluding the Neutral Zone). This suggests Riyadh is willing to cautiously and temporarily stick with other Opec producers in sharing some of the burden of

(continued on p.4)

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Alaskan Oil Profits Staying Buoyant Amid Volatile Prices

With oil markets again threatening a possible sharp drop in prices, US Alaskan production looks surprisingly well positioned to cope with a repeat of the collapse of 1986. Despite high transport costs that would appear to make Alaskan North Slope output highly vulnerable to lower prices, it is currently making good profits at $14.50-$15.50 delivered prices, and has shown it can break even at $10 a barrel. Profits also bounce back quickly as prices recover, according to a PIW analysis of Alaskan North Slope economics (see table). Producers briefly suffered losses of a few pennies a barrel in mid-1986 when the delivered price at the Gulf Coast fell to $10. But profits rebounded to an average $3.50 in 1987, and even managed to average over $1 a barrel in disastrous 1986. ANS crude — which is one-fourth of US production — realizes a healthy $2.60-$3.20 a barrel now, depending on sales destination.

Even if prices dropped below $10, very little North Slope production would be shut in, mainly because of the large amounts already invested in current output and its importance to US supply. What's more, the oil is primarily absorbed into the refining and marketing systems of producing companies, and low crude prices usually provide

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offsetting improvements in the profitability of downstream refining. Meanwhile, the long-term outlook for Alaskan North Slope crude is encouraging a continuing buildup of production capacity, in sharp contrast to plunging production in other US areas. ANS output surged over 2-million b/d in late 1987 as Alaska displaced Texas for the first time as the largest source of US crude. The North Slope is still regarded as holding the best potential for finding big new fields. But discoveries have to be large to offset growing development and operating costs, already apparent at the Kuparuk River and Endicott fields, and for enhanced recovery in super-giant Prudhoe Bay (PIW Jan.25,p10).

Since the 1986 price collapse, the economics for Alaskan North Slope crude sold on the West Coast have become relatively more profitable than the longer shipments to the Gulf and East Coasts, which used to earn almost as much. As a result, more North Slope crude is moving to the California market, with the West Coast absorbing 60% of last year's higher production versus 50% in 1985. Profits on West Coast sales are now about 65¢ a barrel higher than those to Atlantic ports, compared to a gap of 10¢ in 1985. This mainly reflects the much larger $11.66 a barrel drop in ANS prices to Gulf and East Coast destinations in the last two years compared to a drop of just under $10 on the West Coast. The bigger decline in the east is hard to explain but is probably only partly due to the highly competitive Atlantic Basin crude oil market.

THE COMPARATIVE ECONOMICS OF ALASKAN NORTH SLOPE PRODUCTION (In dollars per barrel)

	Sales To US Gulf Coast						Sales To US West Coast					
	1988	1987		1986		1985	1988	1987		1986		1985
Delivered Price	Current	2nd H	1st H	2nd H	1st H	Year	Current	2nd H	1st H	2nd H	1st H	Year
Sohio Price	$15.50	$18.45	$17.00	$12.00	$16.80	$27.00	$14.50	$17.45	$16.00	$11.00	$15.80	$25.00
Average Price(a)	15.25	16.82	16.95	12.31	15.72	26.91	14.25	15.48	15.56	10.75	14.54	24.23
Less:												
Shipping Cost	3.35	3.21	3.19	3.38	3.72	4.21	0.99	0.96	0.94	0.94	1.14	1.29
Valdez f.o.b.	11.90	13.61	13.80	8.93	12.00	22.70	13.26	14.52	14.62	9.81	13.40	22.94
Less:												
Pipeline Loss	0.05	0.10	0.05	0.05	0.05	0.10	0.05	0.10	0.05	0.05	0.05	0.10
Pipeline Tariff	3.20	3.95	3.95	4.50	4.50	6.00	3.20	3.95	3.95	4.50	4.50	6.00
Wellhead Price(b)	8.65	9.56	9.80	4.38	7.45	16.60	10.01	10.47	10.62	5.26	8.85	16.84
Less:												
Royalty(c)	1.00	1.11	1.14	0.47	0.85	1.99	1.17	1.23	1.24	0.58	1.02	2.02
Severance(d)	0.91	1.00	1.30	0.59	0.99	2.19	1.05	1.09	1.40	0.70	1.17	2.22
Property Tax	0.15	0.15	0.15	0.18	0.18	0.21	0.15	0.15	0.15	0.18	0.18	0.21
Producing Cost	0.85	0.85	0.85	0.75	0.75	0.90	0.85	0.85	0.85	0.75	0.75	0.90
Depreciation(e)	2.25	2.25	2.25	2.17	2.17	1.53	2.25	2.25	2.25	2.17	2.17	1.53
Pre-Tax Profit	3.49	4.20	4.11	0.23	2.51	9.78	4.54	4.90	4.72	0.88	3.56	9.96
Less:												
State Income Tax(f)	0.10	0.13	0.12	0.01	0.08	0.29	0.14	0.15	0.14	0.03	0.11	0.30
US Windfall Tax(g)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
US Income Tax(h)	1.19	1.43	1.40	0.11	1.16	4.50	1.54	1.67	1.61	0.41	1.64	4.58
Oil Profit	2.20	2.64	2.59	0.12	1.28	4.99	2.86	3.09	2.98	0.45	1.81	5.08
Pipeline Profit	0.43	0.53	0.53	0.64	0.64	2.18	0.43	0.53	0.53	0.64	0.64	2.18
Overall Profit	2.63	3.17	3.12	0.76	1.92	7.17	3.29	3.62	3.51	1.09	2.45	7.26

a) Average of all producers. b) Price at Pump Station #1. c) Royalty 12.5% after deduction of gathering costs (63¢ 1988, 66¢ 1987 & 1986, 65¢ 1985). d) Severance Tax based on wellhead price after deduction of royalty (11.94% from 2nd Half 1987 to present, 14.96% 1985 to 1st Half 1987. e) Includes depletion. f) Average state income tax rate of 3% for all producers. g) Windfall profits tax not applicable at lower wellhead prices. h) US income tax rate 34% 1987 to present and 46% previously, after deduction of costs, state taxes.

Another big change in the last few years is the more even split between producing company profits and the tax take of federal and state governments. With Alaskan wellhead prices well below the floor level of US "windfall" taxation, the tax burden has shrunk to an estimated $3.35 a barrel currently. Reduced corporate income tax rates from 46% to 34% starting in 1987 has also helped producers. However, Washington claims that the companies may owe $200-million in "windfall" profits taxes for 1984 and 1985 due to disparities in pricing and pipeline charges among the various Alaskan oil producers (PIW June 13,'83,p3).

The settlement of a 7-year legal dispute over Alaskan pipeline tariffs has also put an extra squeeze on profits since 1986, with the Trans-Alaskan Pipeline providing 15% of North Slope profits now compared to 30% in 1985. Aimed at fostering greater competition for North Slope leases, the resolution with the seven owners (BP 50%, Exxon and Arco

20% each, and the rest split between Mobil, Phillips, Union and Amerada Hess) sharply reduced tariffs, settled back claims of overcharges and put the pipeline on a real-rate-of-return basis starting in 1986 (PIW Nov.4,'85,p8).

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US ...n't End ...ans For ... ...ole

The existence of a semi-secret and unofficial "mini-Brent" North Sea market might help London's International Petroleum Exchange win a central role in the globalization of oil futures dealing. Mini-Brent could provide a model for the IPE as it prepares another relaunch for its failed Brent futures contract following the New York Mercantile Exchange's refusal to trade US crude futures in London as a joint venture (PIW Jan.25,p8). Shocked and disappointed by Nymex's rejection of joint trading of West Texas Intermediate futures, the IPE is considering a number of alternative options, with a restyled 1,000-barrel Brent contract based on cash settlement rather than physical delivery at the top of the list (PIW Jan.25,p8). Other possibilities include a London-based West Texas Intermediate contract administered independently of Nymex, and a link to another US exchange such as the Chicago Board of Trade, which dabbled with oil futures several years ago.

Steady but largely unpublicized trade in the unregulated mini-Brent market leaves little doubt that demand exists for a financial tool of this type geared to European crude. Also known as the Brent partial market, and only reluctantly revealed to PIW by major players, mini-Brent is the brainchild of US investment banks. But its future is now in doubt due to new UK laws which may leave room for the IPE to take over instead. Mini-Brent works because the investment banks are willing to buy and sell futures contracts for part-cargoes of Brent in 50,000 barrel increments under their own set terms, normally closing out at an agreed cash-settlement price as 600,000-barrel forward Brent cargoes begin to trade in the physical market. However, this trading could fall foul of the forthcoming UK Financial Services Act (PIW Jan.11,p2). The IPE, as a recognized futures exchange, might win approval of a similar standard contract, using well-established procedures of exchange-of-futures-for-physicals for participants wanting to take delivery. The IPE is now seeking industry advice on how to tailor a new contract, but there's virtually universal agreement that simply restyling the existing 1,000-barrel contract won't work.

Even with its poor track record in marketing and planning, the London futures exchange is still eager to launch its own crude contract that will spark trade both locally and from Mideast and Far East time zones, largely out of New York's normal reach. It plans "some form of significant trading incentive scheme to encourage initial participation" and scope for broader membership, aimed at attracting more active floor traders. While Nymex boasts almost 800 members and last year traded an average 40-million b/d, there are currently just 57 authorized IPE dealers. There's general dismay in European trading circles over the Nymex's "parochial" decision not to come to London, coupled with the recognition that Eastern Hemisphere traders increasingly want to use crude futures (PIW Dec.7,p6). The IPE has already been approached by the Singapore International Monetary Exchange on possible broad cooperation.

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In Opec ...tives To ...counting

Like the big Mideast exporters, Opec's key African members are moving fast to cushion themselves against rapid swings in output even in a weak market. But they are using very different means to achieve the same ends. Resisting straight market-related pricing, the Africans are looking to product sales, processing deals of various kinds and enhanced margins for foreign equity producers to sustain volumes. Though techniques differ, almost all Opec exporters are adapting to an oil market in which some price volatility is seen as inevitable, making maintenance of sales to key customers in ways that cause the least market disruption a top priority (PIW Jan.25,p1). The various methods reflect marketing strengths of individual producers and preferences of traditional customers, among other factors.

Among African producers, Libya appears to have significantly reduced its vulnerability to short-term market swings. Though volume has fallen somewhat, Tripoli seems to be offsetting much of the recent loss of up to 200,000 b/d in third-party crude sales to traders without flooding the Mediterranean with discounted crude. "They've

APPENDIX C -- EXPLANATION OF 1981 OIL TAX LAW CHANGES

I. Introduction

The 1981 oil tax legislation (ch. 116, SLA 1981) replaced the separate accounting oil and gas corporate income tax, enacted in 1978, with a modified apportionment- based corporate income tax. To make up the substantial loss in revenues caused by this shift, the legislation also raised the severance tax rate on Prudhoe Bay from an effective rate of just over 11% (with the ELF) to 15%. This increase was accomplished by raising the nominal rate from 12.25% to 15% and effectively suspending the ELF until the tenth anniversary of Prudhoe Bay production in 1987. (For fields beginning production after June 1981, the nominal rate was set at 12.25% for the first five years of production.) Taken together, the two changes were intended to be revenue neutral.

In addition to the two primary changes -- eliminating separate accounting and increasing the severance tax -- the 1981 law also:

(a) made retroactive technical amendments (known as the "warts" amendments) to state tax laws in order to improve the retrospective constitutionality of separate accounting;

(b) corrected tax problems posed by the sharing of oil and gas revenues among Native corporations under §7(i) of the Alaska Native Claims Settlement Act;

(c) allowed for the retroactive deduction of federal windfall profit tax payments; and

(d) instituted a graduated, stair stepped rate, beginning at 1%, for the taxation of corporate income under $100,000, and raised the top rate from 9.4% to 11% for one year.

Tax "stability" was not the issue in 1981. The 1981 law was passed solely in response to litigation filed by the oil industry challenging the 1978 separate accounting corporate income tax. Unlike the separate accounting law, which was passed after nearly a decade of study, discussion, and debate, the 1981 oil tax changes were not designed to make the state's tax system fair and predictable, or to encourage future exploration and production. Instead, the 1981 law was designed to limit the state's potential liability as a result of the oil companies' legal challenge to the 1978 separate accounting law. Because the oil industry benefitted from the 1981 law, it did not object to the changes in the state's oil tax structure.

At the time the 1981 law passed, many assumed that the oil tax issue would be revisited, after a decision on the 1978 law was made, and before the June 1987 reimposition of the ELF. The state won the separate accounting litigation in the trial court in May 1983 and on appeal to the Alaska Supreme Court in August 1985. The statute's constitutionality was affirmed by the U.S. Supreme Court in January 1986.

II. How It Happened

A. Activity Before 1981

The 1977-78 Alaska Legislature and Hammond Administration, confronted with the prospect of the first commercial production from Prudhoe Bay, instituted a comprehensive revision of the state's oil and gas tax structure. In 1977, the legislature, with the active support of the governor, increased the maximum severance tax rate from 8% (first put in effect in 1970) to 12.25%. An economic limit factor [ELF] formula replaced the statutorily-reduced rates for well production less than one thousand barrels per day (from 1973-1977, a well's first 300 barrels were taxed at 5%, and the next 700 barrels at 6%). The ELF was designed to give the severance tax a curved or sliding scale, instead of stair stepped, rate.

In 1978, the separate accounting oil and gas corporate income tax was enacted. The law was developed and passed in response to detailed analyses, prepared for the legislature and administration from 1970-78, showing that the state's existing apportionment-based corporate income tax would result in Prudhoe Bay oil producers paying less than a third of the statutory rate of 9.4% of net income. The apportionment tax also had the inequitable effect of imposing different tax levels on producers with the same profits in Alaska, in effect penalizing producers with a larger degree of investment and employment in Alaska.

In early 1979, the major Prudhoe Bay oil producers filed suits challenging the constitutionality of the 1978 separate accounting law. Concerned over the amount of revenues at risk in the litigation, in the fall of 1980 the Hammond Administration engaged in substantive settlement discussions with those companies. The options proposed would have required the sacrifice of several hundred million dollars of state revenue in order to settle the litigation.

B. The 1981 Session -- Policy Background

At the beginning of the 1981 session, House and Senate leaders urged the Administration to pursue solutions to the problems posed by the oil industry suit that would not require revenue losses to the state. On March 18, 1981, the leadership of

both chambers, including Senate President Kerttula and Finance Chairmen Dankworth and Bennett, House Speaker Duncan and Finance Chairman Cotten, and Governor Hammond, Attorney General Condon, and Revenue Commissioner Tom Williams, joined in a statement declaring that "any significant decreases in state oil and gas revenues appear both unwarranted and unsupported by a majority of Alaskans. . . . All agree that any changes which would give large sums of money to the oil industry at the expense of the people of Alaska are unacceptable."

House leaders did not agree with the Administration's view that existing law needed to be changed. They were more optimistic that the separate accounting statute would be upheld, as it was in 1986. They believed that the tax structure put in place in 1977-78 was sound, and preferable to the alternatives of a higher severance tax or an apportionment- based income tax. They also believed any changes to state tax laws should be made after, not prior to, any unfavorable court decision, and that the potential problem of having to refund money to the oil industry was better left to the future, if and when it was more than a hypothetical possibility.

C. The 1981 Legislation

Because the Administration felt that some action was required to limit the risk posed by the separate accounting lawsuit, the House developed a "backstop" bill (in conjunction with the Administration), which set an oil and gas reserves tax in place to take effect and preserve state revenues if the 1978 separate accounting law were to be found unconstitutional.

Governor Hammond introduced the backstop bill in May 1981 (as SSHB 200). It passed the House (as SB 524) in early June. A free conference committee, consisting of Senators Ray, Bennett, and Dankworth, and Reps. Gardiner, Vaska, and O'Connell, first met on June 11.

During the latter half of the session, Senator Dankworth had attempted to develop a bill that would succeed in settling the separate accounting litigation while preserving, in substantial part, past and future state oil revenues. He was unsuccessful, and gave up the idea of ending the existing separate accounting litigation. He then attempted to craft a bill that would repeal the separate accounting law prospectively and maintain future state oil revenues at a level roughly comparable to those collected under the separate accounting law.

On June 17, following the reorganization of the House, Rep. Halford replaced Rep. Vaska on the conference committee and became the House chair. At that time, the oil industry circulated a settlement proposal which repealed separate accounting, increased severance taxes, and instituted a 10% investment tax credit. The oil

industry estimated the proposal's revenue loss to the state for FY 82-85 at $1.37 billion; legislative staff estimates of revenue losses ranged from $1.5 to $2.1 billion.

Senator Dankworth prepared a draft bill embodying the settlement proposal, and distributed it to the conference committee on June 22. At a later point in the June 22 meeting, he also distributed a draft bill that modified the settlement proposal in two important ways, in order to make the bill as revenue neutral as possible. He abandoned the 10% investment credit and suspended the application of the ELF during a field's first ten years of production in order to achieve a 15% effective severance tax rate at Prudhoe Bay. As a result of these changes, the oil industry was not willing to settle the litigation, and stated in testimony that they would continue the separate accounting litigation even if the modified proposal were enacted.

Prior to the next meeting of the conference committee on June 23, Governor Hammond wrote a letter to all legislators clarifying his position on the oil tax issue. He stated his preference was for a public vote on the backstop bill versus the oil industry settlement proposal. Alternatively, he urged the Senate to pass the backstop bill, and stated he preferred passage of any proposal to doing nothing. He noted that legislative action should "[r]educe the likelihood that the oil tax issue will continue to be a perennial political liability for those in public office."

On June 23, Senator Dankworth submitted to the conference committee the legislation ultimately signed by Governor Hammond, described on the first page of this appendix. The June 23 bill, known as "Dankworth 3," retained the basic characteristics of Senator Dankworth's earlier proposal, but suspended the application of the ELF during the first ten years of production only if the ELF was greater than .7. The change did not affect Prudhoe Bay, but did provide a tax break for Kuparuk.

The June 23 legislation received only cursory examination in the free conference committee and on the floor of the House and Senate before its passage on June 24. No committee report or written analysis was provided by either the bill's sponsor, Senator Dankworth, or the Administration. A bare bones fiscal note, which projected total revenue losses from FY 82-85 of $141 million, did accompany the bill during the legislature's deliberations. Specifically, the note showed revenue losses of $21 million in FY 82, $117 million in FY 83, $18 million in FY 84, and a gain of $15 million in FY 85. No figures for the effect of the reimposition of the ELF on Prudhoe Bay in 1987 were provided. Revenue Commissioner Williams personally prepared the fiscal note and provided no supporting documentation for it, other than stating the estimates were based on confidential figures provided by the oil industry.

Speaker Hayes refused to allow a minority report opposing the legisla ı,

authored by Rep. Gardiner, to be published in the House Journal. At pages 2-3 of the minority report, after questioning the validity of the $141 million estimate, Rep. Gardiner stated the fiscal note "failed to point out an even more significant revenue loss which will occur in the latter half of this decade, due to the sharp decline in severance tax collections from Prudhoe Bay after the reimposition of the economic limit factor in 1987. This loss is on the order of two billion dollars." (The two billion dollar estimate was based on the optimistic oil price assumptions prevailing at the time.) The bill passed over the strenous objections of the former House majority.

At the time he signed the 1981 law, Governor Hammond noted that the new law would only reduce state income by .6%, relying on the figures in the fiscal note.

The key arguments made in opposition to the 1981 law were:

(a) It was not revenue neutral, because the estimates for the amounts to be collected by the new apportionment formula were overstated and speculative.

(b) A future legislature and administration would be saddled with a huge drop in revenues by the reimposition of the ELF in 1987.

Other arguments concerned the harmful effects of a shift from a net income-based separate accounting tax to a gross revenue severance tax.

Both Commissioner Williams and Governor Hammond explicitly recognized that a future legislature would have to deal with the post-1987 revenue effects from reimposition of the ELF. In the press statement issued on July 21, 1981, at the time he signed the oil tax bill, Governor Hammond declared, "As for the possible revenue effects in 1988 and beyond, I have full confidence in the ability of the Legislature to deal at that time with whatever is required to retain the state's 'fair share' of our oil wealth."

In responding to a question about the post-1987 ELF revenue loss at the June 23 conference committee meeting, Commissioner Williams noted that a future legislature would have the option of reimposing separate accounting if it proved constitutional. A newspaper account of the meeting reported that "If the projected revenue loss proves true, Williams said the Legislature would have the option of hiking taxes." (*Anchorage Daily News*, June 25, 1981, p. A4, "Lawmakers Pass Revision of Oil Tax Law.")

During the June 24 House floor debate on the 1981 bill, Rep. Gardiner noted the ELF factor would cause multi-hundred million dollar losses after 1987. Rep. Halford responded that "by that time [1987], if the companies continue to challenge the portion of funds that are in the state's hands under chapter 21 [separate accounting], we should have an answer to that lawsuit. And with that answer, we should be able to develop possibly a more consistent taxing policy at that time. That's

pretty far in the future, but we'll have more information available to us at that time."

III. Postscript

The revenue losses resulting from the shift to the modified appportionment method have exceeded considerably the $141 million estimate for FY 82-85 made in 1981 by Commissioner Williams. Analyses by the Department of Revenue shows the FY 82-85 revenue loss of the 1981 law at over seven hundred million dollars. Through FY 87, the state lost over one billion dollars in revenue as a result of passage of the 1981 law.

The problems arising from the reimpostion of the ELF are the subject of the main body of this report.

Appendix D

DRILLING/WORKOVER DISINCENTIVE
COMMITTEE SUBSTITUTE HB 164

SEVERANCE TAX CALCULATION

CURRENT LAW

Field Rate x *Wellhead Price* x *Severance Tax* x *ELF*

90,168,000 *BOPY* x $9/*BO* x 0.15 x 0.52134

= $63,461,050/year

Addition of 1 well:

90,277,000 *BOPY* x $9/*BO* x 0.15 x 0.5204

=$63,423,203/year

A decrease of $37,846 year

PROPOSED LAW

Field Rate x *Wellhead Price* x *Severance Tax* x *ELF*

90,168,000 *BOPY* x $9/*BO* x 0.16 x 0.7296

=$88,811,873/year

Addition of 1 well:

90,277,000 *BOPY* x $9/*BO* x 0.15 x 0.7292

=$88,870,484/year

An increase of $58,611 year

[Copy of ARCO Handout, March 27, 1987]

TECHNICAL NOTE
ON ARCO'S KUPARUK EXAMPLE

Tax Effects of Drilling an Additional Well Under Current Law

Mr. James Weeks, Kuparuk Unit Manger for ARCO, provided testimony to the House Finance Committee on March 27, 1987. Examples of severance tax effects (see preceding page) accompanied his testimony. The examples compare the severance tax effects of adding one additional well in the Kuparuk field under the current ELF and under the proposed ELF. The examples show that the addition of one well producing just under 300 barrels per day would increase output from 90,168,000 barrels of oil per year (BOPY) to 90,277,000 BOPY. At the $9.00 per barrel price assumed in ARCO's example, annual gross revenue to the owners increases by $981,000.

(90,277,000 BOPY - 90,168,000 BOPY)*($9/barrel) =
(109,000 BOPY)*($9/barrel) = $981,000

The first of ARCO's two examples shows how under current law the owners would collect an annual severance tax *rebate* of $37,846 on this additional revenue. The effective severance tax rate on the new production is thus -3.9 percent. The effect is analagous to a personal income tax where the effective tax rates become lower as increasing income moves the taxpayer into a higher bracket.

The second ARCO example illustrates how this will be changed under the proposed law. Instead of giving the owners a $37,846 windfall, the proposed law will collect $58,611 (6.0 percent) of the incremental $981,000 for the state in severance tax. The table below summarizes the effects under the current and proposed severance tax laws, as shown in the ARCO examples.

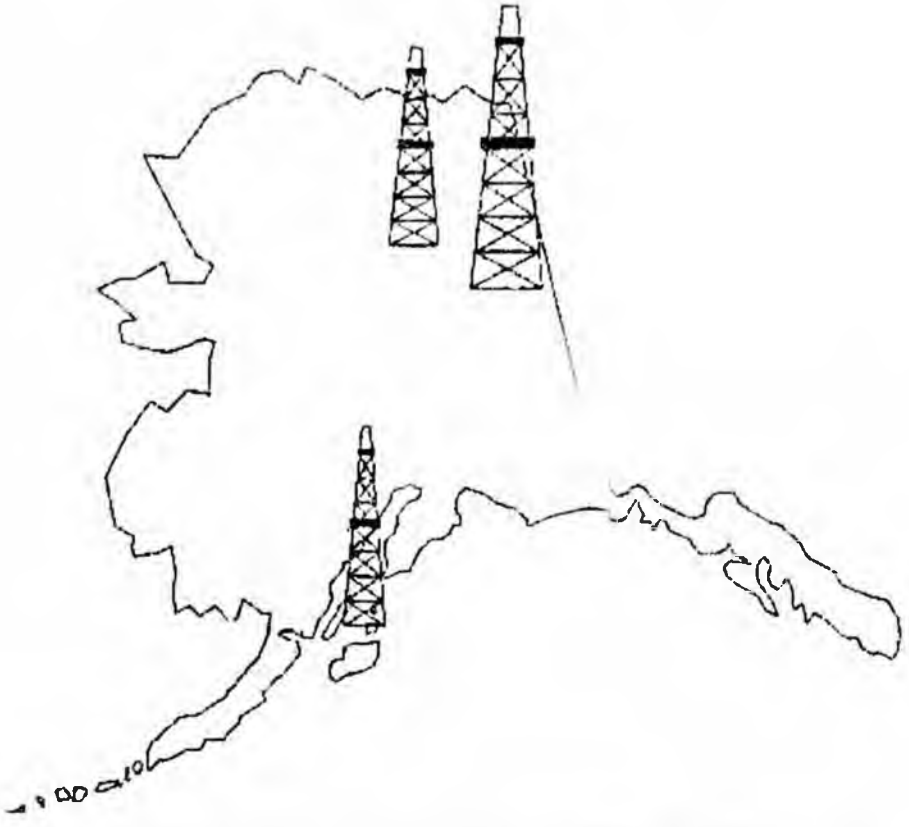
TAX EFFECTS OF DRILLING ONE ADDITIONAL WELL
(ARCO Kuparuk Example)

	Change In Annual Gross Revenue	Annual Severance Tax	Tax Rate On Incremental Production	Average Tax Rate Before Drilling	Average Tax Rate After Drilling	Percent Change In Average Tax Rate Due To Drilling
Current Law	$981,000	($37,846)	-3.9%	7.820%	7.806%	-0.180%
Proposed Law	$981,000	$58,611	6.0%	10.944%	10.938%	-0.055%

Prepared by Division of Policy, April 1987.

f - ELF

Oil Industry Profitability in Alaska 1969 through 1987



Prepared for the Department of Revenue
State of Alaska

by

Edward B. Deakin

Distinguished Enterprise Professor and
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University of Texas

March 15, 1989

Edward B. Deakin is the Distinguished Enterprise Professor at the University of North Texas in Denton, Texas. He directs the Institute of Petroleum Accounting there. He is on leave from his position as the Price Waterhouse Centennial Professor of Accounting at the University of Texas and has also held professorships at Stanford University and the University of Kuwait. Professor Deakin has written more than fifty articles and books, many of which addressed issues in the field of petroleum accounting. He has been an advisor to the U.S. Departments of Energy, Interior, and Treasury on issues related to oil industry accounting. He has also advised several state governments, including the State of Alaska, as well as a number of private companies. He served on two task forces of the Financial Accounting Standards Board which dealt with oil industry accounting matters. He holds a Ph.D. from the University of Illinois and C.P.A. certificates from the states of Illinois and Texas.

Department of Revenue Press Release

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March 15, 1989

A petroleum accounting expert says the oil industry has earned more than $42 billion in Alaska in after-tax profits from 1969 through 1987 -- including more than $460,000 per hour since the super-giant Prudhoe Bay field began producing in 1977.

According to the study by University of Texas Professor Edward B. Deakin, the industry's share of profits from Alaska operations since 1969 is 45 percent greater than the $29.3 billion received by the state. The state collects oil revenues through royalty, tax and lease payments.

Most of the oil company profits leave the state. The study found that the oil industry's cash flow, which includes profit and repayment of original investment, has exceeded $61 billion. The study calculates that the industry has re-invested approximately 28 percent of its cash flow in Alaska since Prudhoe Bay began producing in 1977.

Industry after-tax profits in Alaska in 1986 and 1987 averaged more than $8 million per day. In 1986 -- the year following a sharp decline in the world price of oil -- Deakin found that Alaska North Slope production and pipeline profits were $5.23 per barrel. In 1987 that figure rose to $5.47 per barrel. The industry's $42.6 billion in profits since 1969 represents a profit of $6.59 per barrel for all Alaska activities.

Deakin's study focuses primarily on North Slope production and the trans-Alaska pipeline, which account for $41.5 billion of the industry's Alaska profits since 1969. His analysis does not consider additional profits earned by the North Slope operators on transportation, marketing and refining of Alaska crude oil after it leaves the state.

The 110-page accounting analysis, prepared under contract to the Department of Revenue, is based on public documents, including annual reports and corporate filings with the Securities and Exchange Commission, the Federal Energy Regulatory Commission, state publications and reports by financial analysts.

In addition to his position as Price Waterhouse Centennial Professor of Accounting at the University of Texas at Austin, Deakin is also Distinguished Enterprise Professor and Director of the Institute of Petroleum Accounting at the University of North Texas. He is a certified public accountant, holds a Ph. D. and has served on two task forces of the Financial Accounting Standards Board (F.A.S.B.) which dealt with oil industry accounting matters. He has advised the federal government, as well as various states and companies on issues related to oil industry accounting.

= 30 =

SUMMARY

Total Profit. The oil industry received an estimated $42.6 billion in profit from production and transportation activities in Alaska from 1969 through 1987. The $42.6 billion represents amounts accruing to producers after accounting for all expenses, including exploration, lease acquisition and income taxes, and allowing for recovery of investment costs (depreciation). The main section of this report presents details of profit for each calendar year. The technical section of this report describes each component of the profit, investment and cash flow elements. Below is a summary statement.

Total Alaska Oil Profit
1969 through 1987
(billions of dollars)

Revenues:		
Production revenues	$ 97.6	
TAPS revenues	33.7	
Total Revenues		**$131.3**
Expenses:		
Depreciation	12.1	
Operating Expenses	9.1	
Exploration Expenses	4.1	
Overhead	.8	
Interest	7.5	
Royalty	11.8	
Severance Taxes	10.4	
Property Taxes	3.5	
State Income Taxes	3.6	
Windfall Profit Taxes	6.4	
Federal Income Taxes	19.4	
Total Expenses		88.7
Profit		**$ 42.6 Billion**

Profit per barrel: $6.59

Alaska North Slope (ANS) production contributed $29.1 billion to profit, with $27.8 billion of this amount attributable to Prudhoe Bay and $1.3 billion

attributable to Kuparuk. TAPS provided $12.4 billion. Production in Alaska other than ANS production added $1.1 billion in profit. (Lisburne is included with Prudhoe Bay and Milne Point with Kuparuk. Endicott did not have significant production until after 1987. Alaska production other than ANS production is at Cook Inlet).

Shares. The $42.6 billion in after-tax profit that accrued to the oil industry compares to $29.3 billion in State of Alaska receipts from oil industry activities during this period. During the same period, Federal government receipts were $25.8 billion from these activities.

Investment. From 1969 through 1987, the industry invested $25.0 billion in ANS development costs and for TAPS. $13.1 billion of this represents the initial costs of Prudhoe Bay and TAPS. Of the $25.0 billion investment, $11.6 billion has been recovered through depreciation charges ($6.6 billion from Prudhoe, $1.0 billion from Kuparuk and $4.0 billion from TAPS).

Rates of Return on Investment. Cash flows from all Alaska investments from 1976 through 1987, assuming no debt, total $61.3 billion ($41.8 billion of profit plus $12.0 billion of depreciation plus $7.5 billion of interest[1]). Comparing these cash flows to the investment amounts over time implies that the after-tax rate of return on Alaska investments has been 29.7% from 1976 through 1987. Assuming that 75% of the initial investment was borrowed, an assumption that is indicated by available data, the rate of return on the investment is 43.7% after tax.

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[1]Interest is added back under the assumption of no debt because there would be no interest expense if the entire project were funded with equity. This analysis incorporates all ANS investments prior to 1976 into 1976 and 1977. A more detailed timing of these investments was beyond the scope of this study. As indicated in the technical discussion, the effects of this assumption create minimal changes in the results.

These rates of return compare to the long run rate of return on the New York Stock Exchange of 10% *before* tax. [*Wall Street Journal* (February 20, 1989)] The prime rate peaked at 21.5% *before* tax in 1982, but that was an exceptional year. During this period, a prime rate of 10% to 18% *before* tax was more typical. Using an average effective tax rate of 36%, which approximates the tax rate observed in this study, the equivalent after-tax return on the New York Stock Exchange is 6.4%. The equivalent peak prime rate after an effective tax rate of 36% is 13.76%.

Reinvestment of Alaska Cash Flows. Subsequent to the initial investment for Prudhoe Bay field and TAPS, the industry invested $15.8 billion for ANS development and exploration throughout Alaska from 1978 through 1987. This includes $3.9 billion in exploration expenses which are not included in the analyses of profits from individual fields. The reinvestment rate has been 27.8% of cash flows received during this period.

Seventy-five sources of data about Alaska oil operations were researched to develop this report. Although details do not exist on each and every data item, the information available in the references is sufficient to develop a reasonably accurate picture of industry profit. A study of the data suggests that the actual profit number could be as low as $41 billion or as high as $47 billion. The estimate reported here is at the conservative end of this range.

Oil Industry Profit in Alaska: 1969-1987
Overview

How profitable is the oil industry in Alaska? This is a question of major significance to the State of Alaska and to its residents because the State's share of the revenues from oil production and transportation activities are a primary factor in determining the State's General Fund revenues as well as the additions to the Permanent Fund. This report looks at available information on industry activities in Alaska to derive a picture of the profit attained from these activities. The results of the study indicate that the oil industry received $42.6 billion in after-tax profit from 1969 through 1987 from oil production and from TAPS. The components of this profit estimate are given in Table 1:

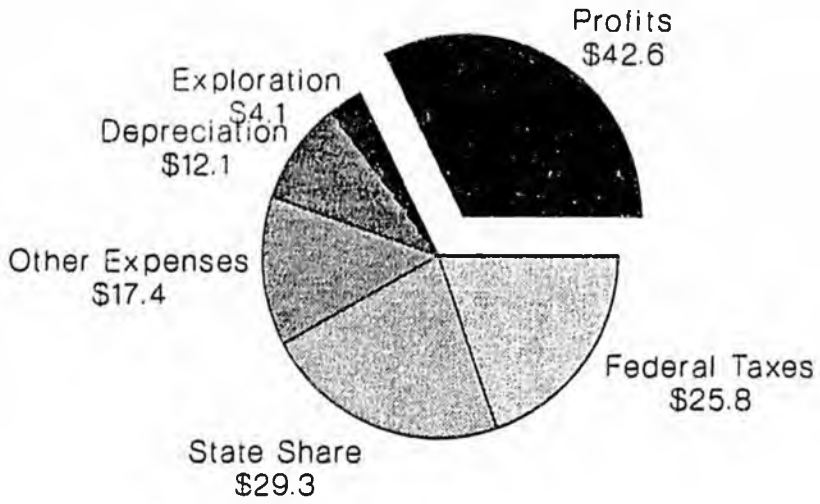
Table 1
Total Alaska Oil Profit
1969 through 1987
(billions of dollars)

Revenues:		
Production revenue	$ 97.6	
TAPS revenue	33.7	
Total Revenues		**$131.3**
Expenses:		
Depreciation	12.1	
Operating Expenses	9.1	
Exploration Expenses	4.1	
Overhead	.8	
Interest	7.5	
Royalty	11.8	
Severance Taxes	10.4	
Property Taxes	3.5	
State Income Taxes	3.6	
Windfall Profit Taxes	6.4	
Federal Income Taxes	19.4	
Total Expenses		88.7
Profit		**$ 42.6 Billion**

Profit per barrel: $6.59

Figure 1 graphs the relationship among the revenues, expenses and profit for all Alaska oil production and transportation activities.

Figure 1
Revenues, Expenses and Profit
All Alaska Oil Activities
(billions of dollars)



The $42.6 billion in profit is what the producers received after accounting for all expenses, including exploration, lease acquisition, and after allowing recovery of the costs of investments in Alaska oil activities related to the useful lives of the investments.[1]

From 1977 through 1987, virtually all of these profits were earned from the Alaska North Slope (ANS). ANS production contributed $29.1 billion to profit, with $27.8 billion of this amount attributable to Prudhoe Bay. Total production profit for the Prudhoe Bay field is given in Table 2.

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[1]Details of how the profit estimates were obtained are provided in the technical discussion. Some of the amounts could not be readily determined from publicly available data or the data were ambiguous. In these situations, a conservative approach was taken. As a result, this report gives a low-end estimate of oil industry profits. Throughout this report, the sum of the individual numbers may not add to identical totals due to rounding.

Table 2
Total Prudhoe Bay Production Profit
1977 through 1987
(billions of dollars)

Production Revenue	$ 83.5
Less Expenses:	
Depreciation	6.6
Operating Expenses	4.4
Overhead	.7
Interest	1.3
Royalty	10.0
Severance Taxes	9.9
Property Taxes	1.4
State Income Taxes	2.5
Windfall Profit Taxes	5.9
Federal Income Taxes	13.0
Profit	**$ 27.8 Billion**

Profit per barrel: $5.81

Figure 2 shows the division of these revenues, expenses and profit.

Figure 2
Revenues, Expenses and Profit
Prudhoe Bay Production
(billions of dollars)

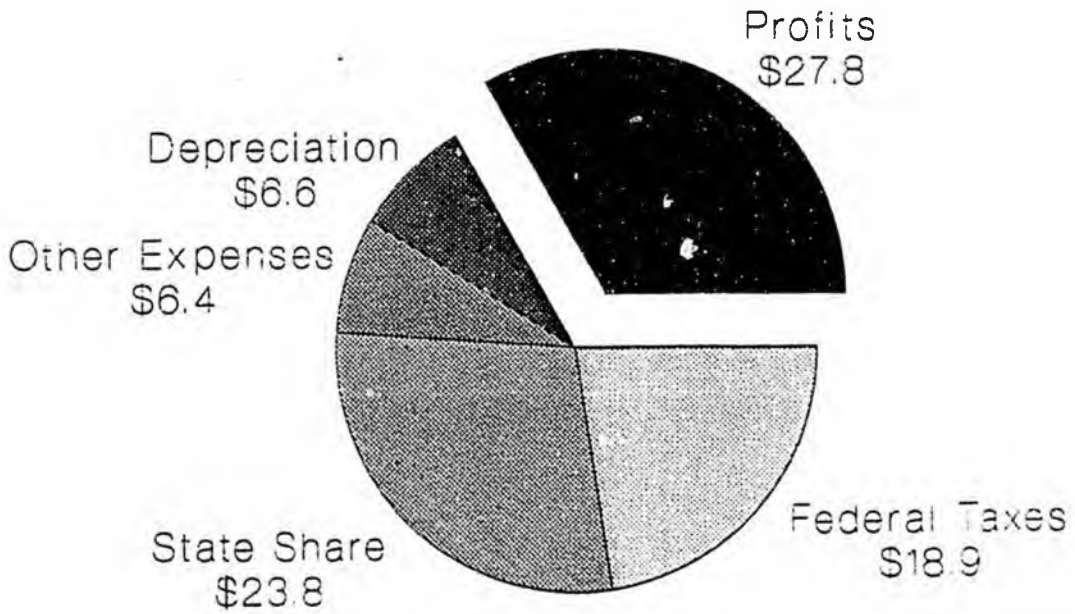


Table 3 shows Prudhoe Bay production profit for the oil producers on a year-by-year basis from 1977 through 1987.

Table 3
Profit from Prudhoe Bay Production
(millions of dollars)

1983 - 1987:

	1987	*1986*	*1985*	*1984*	*1983*
Production Revenue	$6,573	$4,327	$9,847	$10,097	$10,079
Expenses:					
Depreciation	1,074	1,110	873	710	632
Operating Expenses	740	514	535	578	394
Overhead	109	104	139	89	93
Interest	146	139	141	119	119
Royalty	787	518	1,179	1,209	1,207
Severance Taxes	787	571	1,300	1,333	1,331
Property Taxes	150	148	150	148	147
State Income Taxes	83	37	165	171	172
Windfall Profit Taxes			39	211	426
Federal Income Taxes	917	0	2,212	1,469	1,756
Profit	**$1,780**	**$1,186**	**$3,114**	**$4,061**	**$3,801**
Profit per barrel:	**$3.55**	**$2.40**	**$6.25**	**$8.26**	**$7.75**

1977 - 1982:

	1982	*1981*	*1980*	*1979*	*1978*	*1977*
Revenue	$11,271	$13,330	$9,541	$5,892	$1,849	$ 717
Expenses:						
Depreciation	581	510	476	320	254	38
Operating Expenses	504	546	182	184	157	46
Overhead	77	51	15	2	0	2
Interest	139	17	10	156	203	117
Royalty	1,350	1,596	1,143	706	221	86
Severance Taxes	1,488	1,291	924	622	195	76
Property Taxes	147	146	146	123	104	30
State Income Taxes	168	669	550	367	67	30
Windfall Profit Taxes	1,375	3,089	797			
Federal Income Taxes	2,125	1,971	2,086	383	9	32
Profit	**$3,315**	**$3,443**	**$3,212**	**$3,030**	**$ 639**	**$ 260**
Profit per barrel:	**$6.78**	**$7.09**	**$6.61**	**$7.39**	**$1.84**	**$2.58**

The Kuparuk field is the second major source of production profit on the ANS. Total producer profit after taxes from this field are shown in Table 4.

Table 4
Total Kuparuk Production Profit
1982 through 1987
(billions of dollars)

Production Revenue	$ 5.1
Less Expenses:	
Depreciation	1.0
Operating Expenses	.7
Overhead	.1
Interest	.2
Royalty	.5
Severance Taxes	.4
Property Taxes	.2
State Income Taxes	.1
Federal Income Taxes	.6
Profit	**$ 1.3 Billion**
Profit per barrel: $3.66	

Annual Kuparuk profits are shown in Table 5.

Table 5
Kuparuk Production Profit
(millions of dollars)

	1987	*1986*	*1985*	*1984*	*1983*	*1982*
Production Revenue	$1,055	$ 644	$1,282	$ 767	$ 707	$ 591
Expenses:						
Depreciation	263	254	204	117	112	83
Operating Expenses	174	110	125	100	77	78
Overhead	20	20	25	11	11	7
Interest	32	32	33	20	21	20
Royalty	113	69	137	82	76	63
Severance Taxes	85	52	103	62	57	48
Property Taxes	44	41	35	20	17	14
State Income Taxes	10	2	19	11	10	8
Federal Income Taxes	105	0	247	91	102	104
Profit	**$ 207**	**$ 65**	**$ 351**	**$ 254**	**$ 222**	**$ 165**
Profit per barrel:	**$2.31**	**$.79**	**$5.04**	**$6.28**	**$6.37**	**$5.80**

Total revenues, costs and profit from Alaska production activities from 1969 to the end of 1987 are given in Table 6.

Table 6
Total Alaska Production Profit
1969 through 1987
(billions of dollars)

Production Revenue	$ 97.6
Less Expenses:	
Depreciation	8.1
Operating Expenses	5.3
Exploration Expenses	4.1
Overhead	.8
Interest	1.7
Royalty	11.8
Severance Taxes	10.4
Property Taxes	1.8
State Income Taxes	2.7
Windfall Profit Taxes	6.4
Federal Income Taxes	14.3
Profit	**$ 30.2 Billion**

Profit per barrel: $4.96

A graph showing the distribution of these revenues, expenses and profit is shown in Figure 3.

Figure 3
Revenues, Expenses and Profit
All Alaska Production
(billions of dollars)

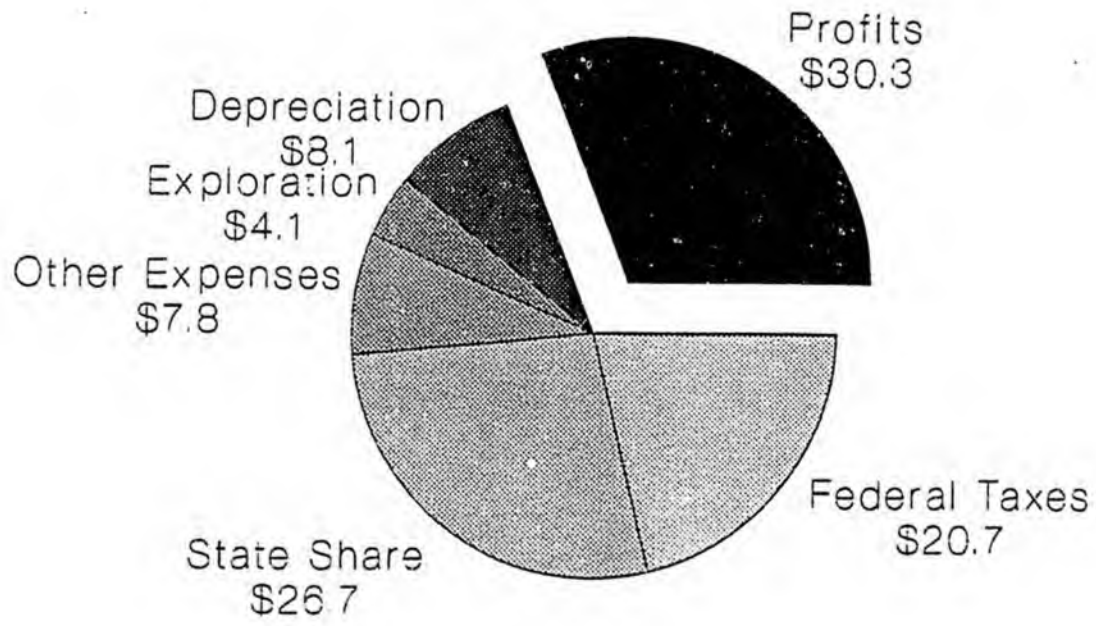


Table 7 shows the annual profits received from production activities in Alaska from 1969 through 1987.

Table 7
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1983 - 1987:

	1987	*1986*	*1985*	*1984*	*1983*
Production Revenue	$8,046	$5,367	$11,735	$11,592	$11,564
Depreciation	1,394	1,418	1,123	866	779
Operating Expenses	940	653	679	678	500
Exploration Expenses	288	288	514	258	818
Overhead	139	133	173	106	111
Interest	192	183	183	148	150
Royalty	970	647	1,414	1,397	1,393
Severance Taxes	871	623	1,403	1,395	1,388
Property Taxes	197	192	188	172	159
State Income Taxes	92	37	182	189	174
Windfall Profit Taxes			39	235	475
Federal Income Taxes	1,007	0	2,424	1,627	1774
Profit	**$1,956**	**$1,192**	**$3,413**	**$4,521**	**$3,841**
Profit per barrel:	**$3.18**	**$2.01**	**$5.83**	**$8.15**	**$6.97**

1978 - 1982:

	1982	*1981*	*1980*	*1979*	*1978*
Revenue	$12,785	$14,484	$9,961	$6,321	$2,254
Expenses:					
Depreciation	698	540	504	345	280
Operating Expenses	506	571	183	188	176
Exploration Expenses	647	419	176	174	274
Overhead	91	55	16	2	a
Interest	171	18	10	167	247
Royalty	1,641	1,745	1,198	762	272
Severance Taxes	1,536	1,291	923	622	195
Property Taxes	165	151	152	130	113
State Income Taxes	175	702	556	369	66
Windfall Profit Taxes	1,491	3,314	861		
Federal Income Taxes	2,212	2,067	2,110	399	8
Profit	**$3,452**	**$3,610**	**$3,270**	**$3,161**	**$ 623**
Profit per barrel:	**$6.33**	**$6.96**	**$6.21**	**$6.97**	**$1.56**

Table 7 (continued)
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1973 - 1977:

	1977	*1976*	*1975*	*1974*	*1973*
Revenue	$ 1,054	$ 380	$ 396	$ 372	$ 377
Expenses:					
Depreciation	53	16	16	16	16
Operating Expenses	64	16	15	10	3
Exploration Expenses	25	25	25	25	25
Overhead	3	a	a	a	a
Interest	177	1	1	a	a
Royalty	131	46	48	45	45
Severance Taxes	76	28	27	15	15
Property Taxes	31	12	13	13	13
State Income Taxes	49	23	24	24	24
Federal Income Taxes	52	85	91	89	89
Profit	**$ 394**	**$ 133**	**$ 142**	**$ 140**	**$ 140**
Profit per barrel:	**$2.49**	**$1.94**	**$1.94**	**$1.89**	**$1.33**

1969 - 1972:

	1972	*1971*	*1970*	*1969*
Revenue	$ 283	$ 279	$ 278	$ 227
Expenses:				
Depreciation	16	16	17	14
Operating Expenses	3	2	1	1
Exploration Expenses	25	25	25	25
Overhead	a	a	a	a
Interest	a	a	a	a
Royalty	34	34	34	27
Severance Taxes	12	11	8	6
Property Taxes	13	10	14	13
State Income Taxes	17	17	17	13
Federal Income Taxes	63	63	64	50
Profit	**$ 99**	**$ 98**	**$ 100**	**$ 79**
Profit per barrel:	**$1.23**	**$1.22**	**$1.17**	**$1.04**

a. Less than $1 million.

TAPS PROFIT

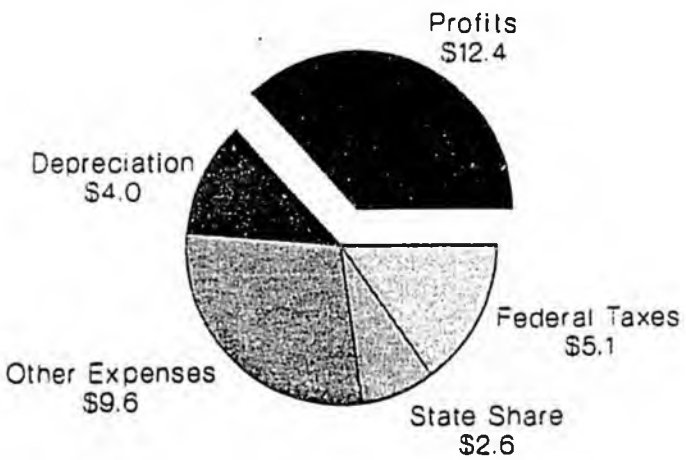
The Trans-Alaska Pipeline System (TAPS) is owned by the Prudhoe Bay producers in approximately the same proportion as their ownership interest in the Prudhoe Bay field. Profit from TAPS, therefore, accrues to the same producers. Table 8 shows the overall revenues, expenses and profit for TAPS from 1978 through 1987.[2]

Table 8
Total Estimated TAPS Profit
(billions of dollars)

Revenue	$ 33.7
Expenses:	
Depreciation	4.0
Operating and Administrative	3.8
Interest	5.8
Property Taxes	1.7
State Income Taxes	.9
Federal Income Taxes	5.1
Profit	**$12.4 Billion**
Profit per barrel: $2.41	

The distribution of these items are shown in Figure 4.

Figure 4
TAPS Revenues, Costs and Profit
(billions of dollars)



[2]The one-half year of activity during 1977 when TAPS started does not have a significant effect on the results. Data from that year are unavailable.

A year-by-year comparison of TAPS profit is shown in Table 9.

Table 9
Annual TAPS Profit
(millions of dollars)

1983 through 1987:

	1987	*1986*	*1985*	*1984*	*1983*
Revenue	$2,765	$3,080	$3,578	$3,926	$3,899
Expenses:					
Depreciation	299	310	309	431	475
Operating and Administrative	255	343	247	387	483
Interest	150	440	411	570	579
Property Taxes	147	164	168	171	165
State Income Taxes	57	55	73	71	66
Federal Income Taxes	631	0	984	610	674
Profit	**$1,226**	**$1,768**	**$1,386**	**$1,686**	**$1,457**
Profit per barrel:	**$2.08**	**$3.07**	**$2.44**	**$3.17**	**$2.77**

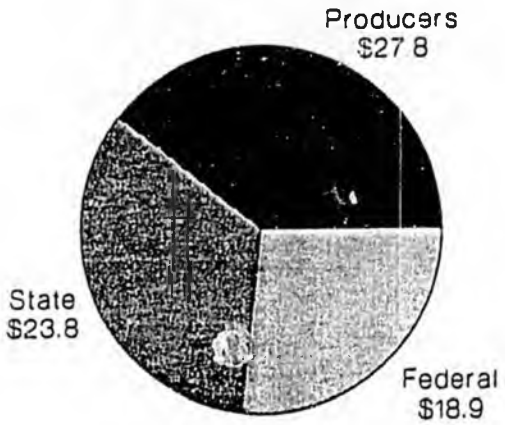
1978 to 1982:

	1982	*1981*	*1980*	*1979*	*1978*
Revenue	$3,896	$3,605	$3,554	$2,963	$2,394
Expenses:					
Depreciation	467	431	503	421	355
Operating and Administrative	498	474	435	330	381
Interest	648	681	720	771	846
Property Taxes	168	171	168	174	174
State Income Taxes	63	203	162	119	60
Federal Income Taxes	802	599	617	129	8
Profit	**$1,250**	**$1,046**	**$ 949**	**$1,019**	**$ 570**
Profit per barrel:	**$2.42**	**$2.15**	**$1.95**	**$2.49**	**$1.64**

SHARES

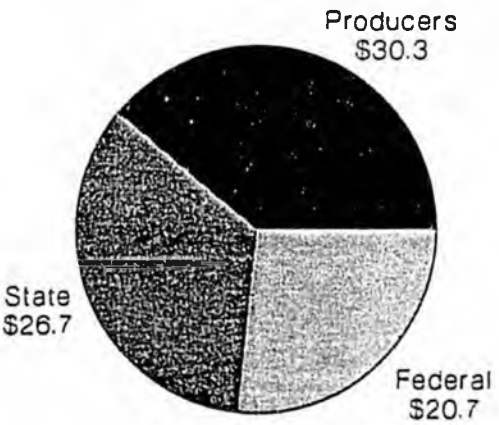
At the super-giant Prudhoe Bay field, producers earned $27.8 billion. The State received $23.8 billion from Prudhoe Bay and the Federal government received $18.9 billion. This is shown visually in Figure 5. The nearby giant Kuparuk field added $1.3 billion to producer profit, $1.2 to the state and $0.6 billion to the Federal government's revenues.

Figure 5
Shares
Prudhoe Bay Production
(billions of dollars)



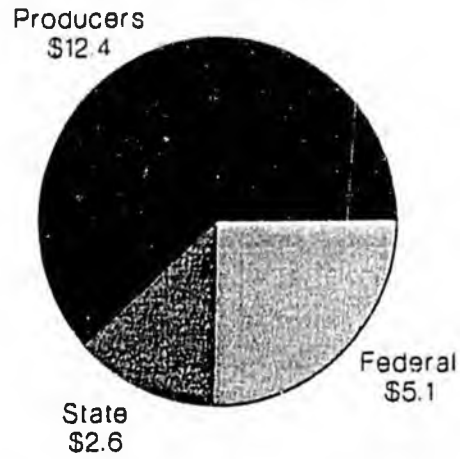
The sharing from all production in Alaska between 1969 and 1987 is shown in Figure 6, with $30.3 billion to the producers, $26.7 billion to the State and $20.7 billion to the Federal government.

Figure 6
Shares
All Alaska Production
(billions of dollars)



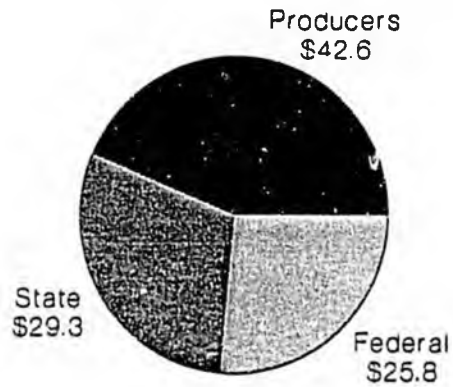
TAPS profit of $12.4 billion went to the producers, $2.6 billion went to the State through property and income taxes and $5.1 billion went to the Federal government through income taxes. This distribution is shown in Figure 7.

Figure 7
TAPS Shares
(billions of dollars)



A summary of the distribution for all Alaska oil operations is shown in Figure 8. The $42.6 billion in after-tax profit that accrued to the oil producers compares to $29.3 billion in State of Alaska receipts from oil industry activities during this period. During the same period, Federal government receipts were $25.8 billion from these activities. Figure 8 shows the relationship between industry profit and the state and federal receipts from oil industry revenues.

Figure 8
Shares
All Alaska Production and Transportation
(billions of dollars)



ADDITIONAL BENEFITS OF ANS OIL

ANS producers receive profits from Alaska oil outside of Alaska which provides an additional bonus beyond what it would cost if they had to purchase imported oil. An additional profit of approximately $0.7 billion went to the producers through the operation of the U.S. Department of Energy crude oil entitlements program. Producers are believed to earn additional profit through the refining of ANS crude because, among other things, they have access to a secure source of crude oil. If they did not have the ANS crude, it would be necessary for them to acquire crude from foreign sources.

Others estimate that profits on tanker operations and trans-Panama shipment activities added between $.25 and $1.00 profit per barrel of ANS crude produced. These additional profits would have been received on the nearly 6 billion barrels of ANS production. These added profits are not included in the $42.6 billion of total oil industry profit in Alaska covered in this report.

INVESTMENTS MADE ON THE ALASKA NORTH SLOPE

Figure 9 shows the relative amounts of money invested in projects to produce ANS crude. The greatest investment was $9.4 billion in TAPS. The total investment to date in Prudhoe Bay was $8.7 billion. This includes the waterflood project and the miscible gas injection project as well as infield drilling. The investment in Kuparuk was $4.3 billion which includes amounts for the newly installed waterflood project that had not been in operation during the period of this study. Milne Point cost $575 million. Endicott and Lisburne each cost approximately one billion dollars. As of the end of 1987, Milne Point had been shut in, while Endicott and Lisburne had just begun operations too recently to have a significant impact on the revenue numbers reported here. The investments made in Cook Inlet during this period were not significant relative to the ANS investments during this period.

Figure 9
ANS Investments
(billions of dollars)

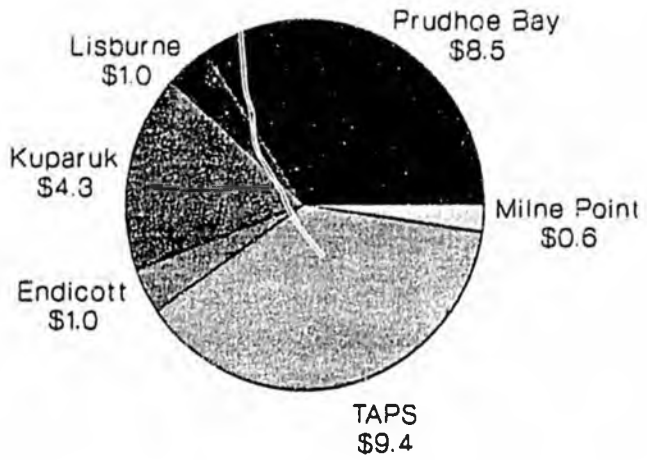


Table 10 shows the timing of the investments in Prudhoe Bay and other ANS projects together with an estimate of the timing of the investment in TAPS. These investment timings are based on information from the producers and may not be exact.

Table 10
ANS Investments
(millions of dollars)

Year	*Project*	*Amount*
1987	Prudhoe gas	$ 720
1987	Kuparuk waterflood	900
1987	Endicott	1,000
1986	Lisburne	1,000
1985	Prudhoe gas plant	720
1984	Milne Point	570
1983	Prudhoe waterflood	2,000
1981	Kuparuk	3,400
1981	Prudhoe drilling	1,100
1980	Prudhoe drilling	250
1979	Prudhoe drilling	250
1977	Prudhoe*	1,850
1977	TAPS*	4,700
1976	Prudhoe*	1,850
1976	TAPS*	4,700
Total		**$ 25,015**

*These amounts were spent over the period 1969 through 1977, with the majority of the funds spent later in the construction phaso of the project.

Cash flows can be related to these investments to compute a rate of return on the investment in Alaska. Assuming the entire investment was made with equity funds, cash flows are deemed equal to profit plus depreciation and interest. A schedule of these "all-equity" cash flows is shown in Table 11.

Table 11
All-Equity Cash Flows
(millions of dollars)

		---Cash Flows---		Net
Year	*Investment*	*Production*	*TAPS*	*Cash Flow*
1987	2,620	3,542	1,675	2,597
1986	1,000	2,793	2,518	4,311
1985	720	4,719	2,106	6,105
1984	570	5,512	2,687	7,629
1983	2,000	4,770	2,511	5,281
1982	0	4,321	2,365	6,686
1981	4,500	4,168	2,158	1,826
1980	250	3,764	2,172	5,686
1979	250	3,673	2,211	5,634
1978	0	1,151	1,771	2,922
1977	6,550	655	0	-5,895
1976	6,550	0	0	-6,550

The equivalent rate of return earned on this stream of cash flows after tax is 29.7%.

As it happened, a substantial portion of the investment was financed with borrowed monies. The 1978 Sohio annual report to shareholders indicated that 75% of the company's funds were from debt. In this case, the investments in 1976 and 1977 as shown in Table 11 would be $1,638 net each year. This is 25% of the investment outflows in those years. The remainder would have been financed with debt. Interest expense would be incurred on this debt and the debt would have to be repaid. The cash flow data in Table 12 is the profit plus depreciation. These cash flows include a deduction for interest expense. Assuming that all of the cash flows were used to pay of the debt as quickly as possible, the loan repayment would have consumed all of the cash flows in 1978

through 1979 and all but $2,131 million in 1980. The net cash flows in each year are shown in column 4 of Table 12.[3]

Table 12
Cash Flows with 75% Borrowing
(millions of dollars)

		-----Cash Flow-----		*Net Cash*
	Investment	*Production*	*TAPS*	*Flow*
1987	2,620	3,350	1,525	2,255
1986	1,000	2,610	2,078	3,688
1985	720	4,536	1,695	5,511
1984	570	5,364	2,117	6,911
1983	2,000	4,620	1,932	4,552
1982	0	4,150	1,717	5,867
1981	4,500	4,150	1,477	1,127
1980	250	3,754	1,452	2,131
1979	250	3,506	1,440	0
1978	0	903	925	0
1977	6,550	478	0	-1,160
1976	6,550	0	0	-1,637

The rate of return implied from the stream of cash flows shown in Table 12 is 43.7%.

REINVESTMENT OF ALASKA PROFIT

A question of importance to Alaska is what happens to the profit earned from oil activities in Alaska. It has been necessary for the industry to make certain investments to maximize production from the Prudhoe Bay field. Initial investments are shown in 1976 and 1977 in Table 10. Reinvestments are shown in Table 10 for the years 1978 through 1987. In addition, the industry has reinvested through exploration.

Reinvestments shown in Table 10 are added to exploration expenses to obtain total reinvestments for the period 1978 through 1987. These reinvestments are shown in the first column of Table 13. For the years 1978

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[3]Loan repayments took place over a longer time period, but it is not feasible within this project to determine actual repayment dates for ANS investment-related debt. This model assumes earlier repayment, but also includes the later interest costs reported by the producers. The net effect of this is to understate the rate of return.

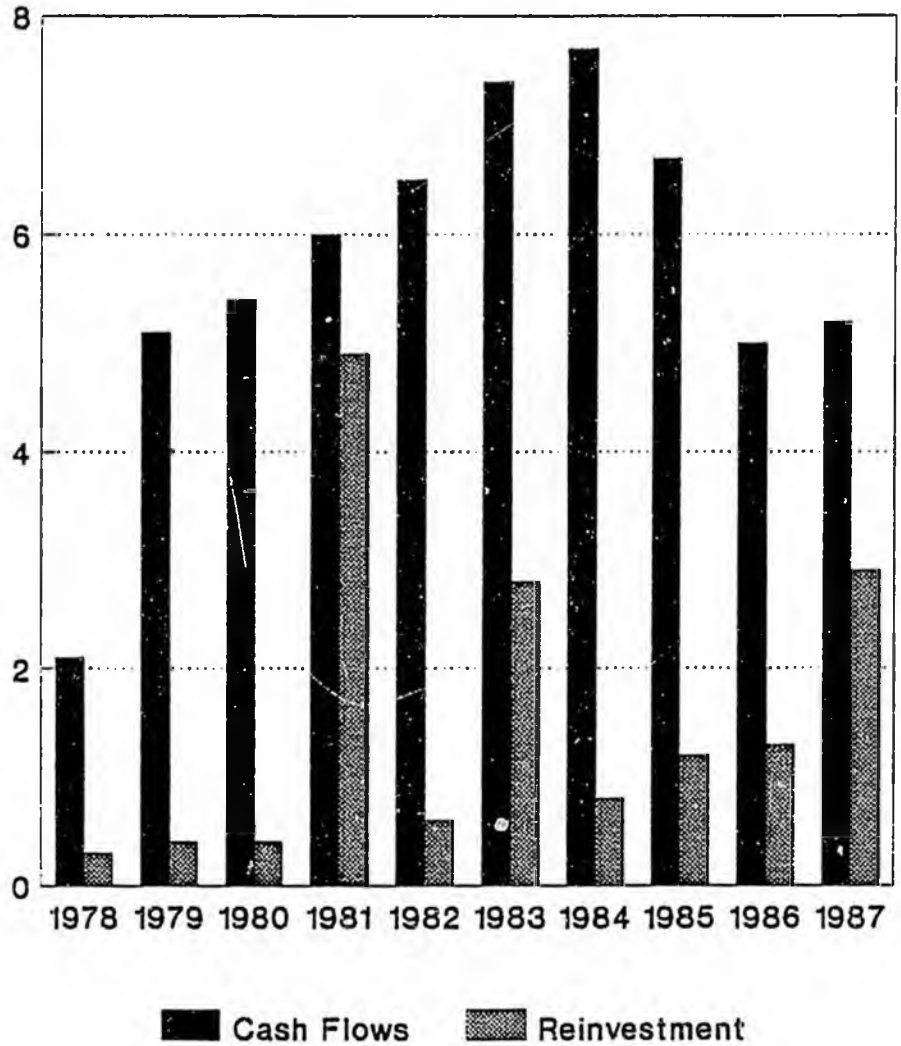
through 1987, these reinvestments are compared to cash flows received from Alaska oil operations. These cash flows are equal to profit plus depreciation and exploration expenses. They are shown as the third and fourth columns in Table 13. Each year's ratio of reinvestment to cash flows is shown in the last column of Table 13.

Table 13
Reinvestment and Reinvestment Flows
(millions of dollars)

	Re-	*----Cash Flows----*			*Reinvestment*
Year	*investment*	*Production*	*TAPS*	*Total*	*Ratio*
1987	2,908	3,638	1,525	5,163	56.32%
1986	1,288	2,898	2,078	4,976	25.88%
1985	1,234	5,050	1,695	6,745	18.30%
1984	828	5,622	2,117	7,739	10.70%
1983	2,818	5,438	1,932	7,370	38.24%
1982	647	4,797	1,717	6,514	9.93%
1981	4,919	4,569	1,477	6,046	81.36%
1980	426	3,930	1,452	5,382	7.92%
1979	424	3,680	1,440	5,120	8.28%
1978	274	1,177	925	2,102	13.04%

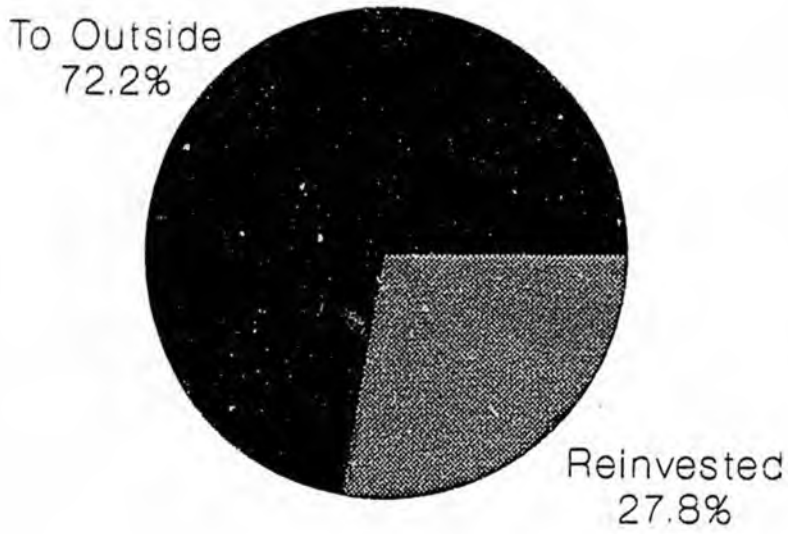
Table 13 indicates that 27.8% of the cash flows from oil and gas industry activities in Alaska was reinvested in Alaska. The reinvestment is shown graphically in Figure 10.

Figure 10
Reinvestment in Alaska by Years
(billions of dollars)



The relationship between the percentage of funds reinvested in Alaska oil projects and those which flow outside is shown in Figure 11.

Figure 11
Overall Reinvestment of Oil Industry Flows
(percentage)



HOURLY PROFIT RATE

Looking at these profits as an hourly earnings number may bring the amounts into better perspective. After-tax profits have been earned by the producers at the rate of $463,144 per hour, twenty-four hours per day for each day of the first ten and one-half years of ANS production.

SENSITIVITY OF ESTIMATES

Where possible, the different assumptions used to develop these profit estimates were studied in more detail to see how sensitive the profit estimates were to the different assumptions. When in doubt, a conservative approach was taken. A total of $7.5 billion in potential profit increases related to assumptions

that were resolved in favor of conservatism was ignored. By contrast, a total of $.6 billion in potential profit decreases related to assumptions were also ignored.

After considering the impact of all potential adjustments due to the assumptions used in the report, the range of profit estimates runs from a minimum of $41 billion to a maximum of $47 billion. The $42.6 billion reported here is at the low end of this range.

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Oil Industry Profitability in Alaska

1969 through 1987

TECHNICAL DISCUSSION

Oil Industry Profitability in Alaska 1969 through 1987

Index to Technical Discussion

Technical Discussion

The profit estimates reported in this report were developed from publicly available information about oil industry activities in Alaska. Although a substantial amount of information exists about oil industry activities in Alaska, a complete picture of profit from Alaska activities is not published in any known reference. Assembling a report on oil industry profit requires gathering information from a number of different sources, piecing together an overall picture of profit and cross-checking the estimate obtained in this manner with other data sources. In the end, the profit estimate should be quite close to the actual results.

Throughout this report the terms "approximate" and "estimate" appear quite frequently. These terms are necessary because public data do not exist which would enable one to compute Alaska profit precisely. The approach taken here, when there are questions about amounts, is to take the conservative approach. The profit reported then will represent the low end of the range. This section of the report provides details on how the pieces of the puzzle were assembled and how the resulting profit estimates were cross checked. After all of this, some questions still remain. The effect of these remaining questions is covered in Section III of this technical discussion.

APPROACH TO MEASURING ALASKA OIL COMPANY PROFIT

In its most fundamental form, profit is the amount that is left over from revenues after paying all expenses including income taxes and an allowance for the cost of the initial investment. In accounting terms, estimation of profit becomes more complex because accountants must relate revenues to expenses that occur in different times. Accounting profits therefore are based on an

analysis of transactions that took place in the past with appropriate adjustments to determine the profit attributable to a specific period of time. In this report, profit from Alaska oil industry activities are estimated over the period 1969 through 1987.[1]

Alaska oil producers earn profit from the production, transportation and sale of crude oil. The primary sources of these profits are production from Prudhoe Bay field on the Alaska North Slope (ANS) and TAPS.

A company engaged in Alaska oil activities can estimate its own profit rather readily by extracting transaction data from its own books and by making appropriate adjustments. To make such an estimate from the outside is much more complex because a significant portion of company data is kept private. Hence, it is necessary to identify that information which is public and piece together a picture of the profitability of Alaska oil operations. This task requires obtaining as much information as possible and then making assumptions about the missing data and, where possible, cross-checking the results with other public data sources. This is the process followed to develop the profit estimates reported here.

For example, Standard Oil Company of Ohio (formerly Sohio, now BP America) includes a section in its corporate annual report that states its profit from Alaska oil production operations. (See Appendix A for an example of this disclosure.) If every other producer obtained the same revenues per barrel of crude oil and incurred the same costs to produce that oil, one could project from the Sohio data to all Alaska production. However, this approach cannot be used because it is widely known that Sohio sells most of its ANS crude on the U.S. Gulf Coast whereas other producers sell their crude oil on the U.S. West Coast.

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[1]See Financial Accounting Standards Board, *Statement of Financial Accounting Concepts No. 3*, Pars. 12 and 56 - 62 for a comprehensive discussion of profit concepts.

Prices in the two markets differ. According to Barclay's de Zoete Wedd (1988), U.S. West Coast prices are about $1 lower than the Gulf Coast, but it costs about $2.45 more to ship a barrel of crude oil to the Gulf Coast. To obtain revenues for all producers, it is necessary to adjust Sohio revenues by taking account of the differences in crude oil values. This is one of the many adjustments necessary to obtain an estimate of profit.

The more assumptions that need to be made, the more questions that will arise about the profit number that is obtained. However, there are alternate sources of information that can be used to compare a significant portion of the data used to compute profit. To the extent that these alternate sources are consistent, the computed profits will be more reliable. The most important item in the profit equation is revenue. Fortunately, estimates of producers can be checked against Alaska severance tax collections. For most of the period covered by this report, the Alaska severance tax is stated as 15% of the value of producers' production, subject to certain adjustments. This implies that for production subject to the 15% rate, an amount equal to 15% of production revenue should approximate the reported severance tax collections by the State of Alaska. Similar comparisons can be made for production subject to other severance tax rates.

In addition, the estimate included in this report is not the only estimate of oil industry profit in Alaska. Financial analysts and others have, from time to time, estimated profit from Alaska oil industry activities. (See Appendices B and C for examples.) The numbers reported here have been checked, to the extent possible, with other data sources.

Not all of the numbers can be checked and many of the alternate information sources use different bases for reporting their data. The last part of section III of

this report discusses the effects that substantial questions raised by the estimation process are likely to have on the total estimated profit. As noted in this report, most of the effects are quite small. This is an unavoidable problem. Indeed, it is very likely that producers are unable to estimate their own profits down to the last cent because of the assumptions that they make in developing their profit numbers. The point is that the estimate developed here is, on balance, consistent with other estimates of profits earned in Alaska. Indeed, the total effect of questions about alternate treatments is that the profit reported here is on the conservative side. One may perhaps argue that total profit is $2 billion higher or lower than this estimate, but such a debate should not detract from the validity of the overall picture presented here.

The first part of this report develops estimated revenues from production activities, essentially the gross receipts from operations. This report focuses on the revenues that accrue to the producers, net of royalty. This is defined as "working interest revenue." To calculate working interest revenue, it is necessary to know production and the value of each barrel of production. Those matters are discussed in Section I under "Production Revenues".

Section II covers the expenses that must be deducted from revenues to obtain profit for this project. These expenses include depreciation, severance taxes, operating expenses, windfall profit taxes, exploration expenses, overhead and interest. Each of these items is discussed in turn. Both the State of Alaska and the U.S. government levy taxes on income as defined in their laws. These are expenses for accounting purposes and are also presented in Section II. Royalties are eliminated from revenues reported by oil and gas producers. In Section III, royalties are included as a separate line item to determine both the working interest (producers') revenues and total revenues.

The third section of the report gives the detailed statements of profit for Prudhoe Bay, Kuparuk and all Alaska production. This section also includes a discussion of the sensitivity of the profit estimates to cost estimates, missing data, various allocations, and other factors on the profit estimates.

The fourth section of the report shows the profit earned from TAPS. Here it is reasonable to rely extensively on Sohio Pipeline Company's disclosures. Other data sources generally confirm the Sohio Pipeline information.

Each part of this technical discussion is designed to provide further detail about the way the data presented in the report was developed. To the extent possible, the report follows accounting practices and conventions that enable one to obtain a reasonable estimate of the profitability of Alaska's oil industry activities. The resulting estimates give an accurate, although not exact, picture of the profitability of Alaska's oil industry operations.

Profit has been estimated for Prudhoe Bay, Kuparuk, all Alaska production and TAPS. After making all of the calculations and cross-checking available data, total oil industry profit in Alaska is estimated as $42.6 billion. This includes $27.8 billion from Prudhoe Bay, $1.3 billion from Kuparuk and $12.4 billion from TAPS. An additional $1.1 billion was earned elsewhere in Alaska.

After looking at the effects of all of the estimates made on reported profit, a range within which the actual number is likely to fall can be developed. The low end of this range is $41 billion and the high end is $47 billion. The estimated profit of $42.6 billion reported here is in the low end of this conservative estimated range.

Finally, reported profit is based on public information which was available at the time this report was written. It is entirely possible that data not available

could affect the analysis. Any such data would be welcomed to advance the goal of obtaining a more precise estimate of Alaska oil industry profit.

I. PRODUCTION REVENUES

PRODUCTION ESTIMATES

Production estimates for crude oil and natural gas were obtained from different data sources and compared. Since the foundation of reported profit depends on production estimates, it is important to note how the estimates compare. Moreover, each company's reported accounting data are based on its production estimates. Thus, the production data are needed for making certain computations from company reports. The estimates for crude oil are discussed first in this section, followed by the estimates for natural gas.

Crude Oil. Production estimates were obtained from the corporate annual reports of Arco, Sohio and BP America, the Alaska Oil and Gas Conservation Commission Statistical Series, DeGolyer and MacNaughton's *20th Century Petroleum Statistics* (1987) and the *International Petroleum Encyclopedia*, as well as from the *U.S. Energy Statistics Sourcebook* (1988). As shown below, the estimates provided by each of these sources differ with respect to the time periods covered, the level of detail and the volumes of production.

The producers' corporate annual reports present production information in terms of barrels per day of production. The data as reported by each company are shown in Table I-1.

Arco presented separate information on the production from Prudhoe Bay, Kuparuk and Lisburne for the years 1980 through 1987. From 1978 on, Sohio/BP presented data for all of its Alaska operations. Prior to 1982, virtually all of Sohio/BP's production was from the Prudhoe Bay field. These data facilitated obtaining production estimates for each of those fields.

Table I-1
Company Net Production Data
(000 barrels per day)

	-------Arco Reports-------			
Year	*Prudhoe*	*Kuparuk*	*Lisburne*	*Sohio/BP*
1987	324.9	122.0	15.0	827.2*
1986	306.9	109.9	4.1	706.4#
1985	304.9	94.9	8.5	699.7
1984	326.1	71.7	8.9	617.9
1983	336.4	69.9	10.0	594.8
1982	292.4	61.8	na	676.6
1981	275.5	2.1	na	698.2
1980	274.7			696.4
1979	248.6**			590.8
1978	213.3**			506.8
1977	213.3**			143.8
1976	78.4**			
1975	27.9**			

* BP America data.
# Sohio data. BP America reported 781.4 thousand barrels per day.
** Arco's total Alaska production.

The data reported in Table I-1 were converted to an annual number by multiplying the daily figures by 365. The company statistics were then divided by the company's proportionate share in production to arrive at an estimate of total production based on each company estimate. Adjustments were made for the 1982 redetermination of each company's Prudhoe Bay share of production. The estimates of total Prudhoe Bay production based on Arco's and Sohio/BP's corporate disclosures are in the first two columns of Table I-2, below. The estimates of total Kuparuk production based on Arco's corporate disclosures are in the first column of Table I-3, below. The corporate disclosures give the company's working interest production (net of royalty).

The Alaska Oil and Gas Conservation Commission provides gross production by field for all years covered by this study. The *International Petroleum Encyclopedia* reports gross production from major fields by year. However, the *Encyclopedia* is not complete. In certain years it does not show all fields.

The DeGolyer and MacNaughton statistics are based on the U.S. Department of Energy reports and show gross production from Alaska. They do not show production from specific fields.

The *U.S. Energy Statistics Sourcebook* data show total ANS production for 1981 through 1987 and total Alaska production for prior years. An assumed 1/8 royalty interest was deducted from this number to arrive at an estimate of ANS working interest production. Production from Kuparuk and Lisburne (based on Arco's disclosures) were deducted to arrive at an estimate of Prudhoe Bay production. These data are in Column 3 of Table I-2.

The estimates presented under each method differed. To test the different estimates for reasonableness, TAPS and Kuparuk pipeline throughputs were analyzed. This analysis is based on the assumption that all of Kuparuk production (including royalty oil) should equal the Kuparuk pipeline throughput. TAPS throughput should be comprised of Kuparuk, Lisburne, and Prudhoe Bay crude, including royalty oil. Deducting Kuparuk, Lisburne and Prudhoe Bay royalty oil should give the working interest production from Prudhoe Bay.

Annual total TAPS throughput for 1982 through 1987 was obtained from the Arco annual report. Similar data for 1980 to 1981 were obtained from the Sohio report. Royalty interests as well as Lisburne and Kuparuk production were deducted from total TAPS throughput to obtain an estimate of Prudhoe Bay production. The results of this analysis are shown in Column 5 of Table I-2.

In addition to these estimates, data on total production from Prudhoe Bay, including royalty, were presented in the *International Petroleum Encyclopedia*. These data were available for 1983, 1984, 1985, and 1987. Royalty of 1/8 was deducted from gross production to obtain another estimate of Prudhoe Bay working interest production for comparison purposes.

The sources that provided reasonably complete data series included Arco, Sohio/BP, the *U.S. Energy Statistics Sourcebook*, the Alaska Oil and Gas Conservation Commission statistics and the analysis of pipeline throughput. The estimated working interest production from Prudhoe Bay based on each of these different estimates is shown in Table I-2. After reviewing the data and the different levels of complexity required for each alternate estimate, it appears that the Alaska Oil and Gas Conservation Commission (AOGCC) statistics provided a reasonable, conservative and consistent data series over the period covered by this report.

Table I-2
Annual Production Estimates: Prudhoe Bay
Net of Royalty
(000,000 barrels per year)

Year	*Arco*	*Sohio/BP*	*U.S. Energy Data Sourcebook*	*AOGCC Statistics*	*Pipeline Throughput Analysis*
1987	544.5	592.0	507.3	500.8	520.9
1986	500.1	508.8	493.6	494.5	493.8
1985	496.8	503.9	497.8	498.5	497.3
1984	531.4	467.5	492.1	491.9	489.6
1983	547.4	458.6	487.3	490.8	486.1
1982	492.7	490.0	489.2	489.2	488.4
1981	493.4	480.8	486.7	485.8	495.0
1980	527.7	479.6	517.7	486.0	479.1
1979	na	406.9	447.4	409.9	na
1978	na	349.0	392.5	348.0	na
1977	na	99.1	148.1	100.9	na

For 1977 through 1986, production estimates used for computing Prudhoe Bay profit are based on the AOGCC statistics shown in Table I-2. The 1987 estimate used the AOGCC estimate for Prudhoe Bay plus Arco's estimate for Lisburne. The production number chosen was neither the highest nor the lowest for all years. It is generally believed that the AOGCC estimates are reliable and acceptable estimates of field production.

Kuparuk production estimates are based on 7/8 of Kuparuk pipeline throughput as reported by Arco. The 7/8 number reflects the net working interest

production. The *International Petroleum Encyclopedia* also reported estimated production from Kuparuk. The *International Petroleum Encyclopedia* data were adjusted to reflect a 1/8 royalty interest. The AOGCC reported Kuparuk production was adjusted to reflect a 1/8 royalty interest also. These different annual working interest production estimates for Kuparuk are reproduced in Table I-3.

Table I-3
Annual Production Estimates: Kuparuk
Net of Royalty
(000,000 barrels per year)

Year	*Arco*	*International Petroleum Encyclopedia*	*AOGCC Statistics*
1987	90.4	87.1	89.6
1986	87.2	na	82.2
1985	70.3	69.6	69.7
1984	40.2	32.6	40.4
1983	38.3	34.0	34.9
1982	28.4	na	28.6
1981	na	na	.1

The Arco data are slightly higher for most of the years of Kuparuk production. Since the differences are minor, the Arco production data were used for Kuparuk. The very small production from Milne Point and Endicott would be included with Kuparuk. However, the amounts are too small to affect the analysis.

Lisburne production was reported by Arco at 14.4 million barrels in 1987. The *International Petroleum Encyclopedia* and the AOGCC reported this production at 14.3 million barrels in 1987. This amount has been included with Prudhoe Bay production in subsequent analysis.

For 1981 through 1987 and for years prior to 1978, other Alaska production was reported separately in the *U.S. Energy Statistics Sourcebook*. These data were used for comparison for those periods. For 1978 through 1980, other Alaska production was estimated as the difference between total Alaska production as reported in the *U.S. Energy Statistics Sourcebook* and ANS

production as computed in the two tables above. The results gave significantly higher estimates of other Alaska production during those three years. It was not possible to ascertain the reasons for the difference between these data and the AOGCC data. The two series of working interest production estimates for non-ANS production reproduced in Table I-4.

Table I-4
Non-ANS Production Estimates
Net of Royalty
(millions of barrels)

Year	*AOGCC Statistics*	*U.S. Energy Statistics Sourcebook*
1987	14.3	14.1
1986	15.4	15.4
1985	14.8	14.8
1984	19.3	19.2
1983	21.7	21.7
1982	24.0	24.0
1981	27.1	27.2
1980	31.7	98.1
1979	37.5	91.4
1978	43.8	87.1
1977	49.1	61.4
1976	58.6	55.5
1975	63.0	61.1
1974	63.2	61.8
1973	64.0	63.3
1972	64.4	63.8
1971	69.0	70.0
1970	73.2	73.2
1969	65.0	64.7

The Alaska Oil and Gas Commission statistics were used for purposes of non-ANS production in this report. The differences between AOGCC and an approach based on the Energy Statistics Sourcebook appears significant only in the years 1977 through 1980. During that period, the AOGCC data appear more reliable because the significant increase in production indicated for 1978 - 1980 by the *U.S. Energy Statistics Sourcebook* cannot be confirmed from other sources. It appears that this increase is a statistical fluke. In other years the two

data series track one another closely. It is unlikely that the differences in other years would have any substantial effect on the results.

Natural Gas. Estimation of natural gas production was simplified because there were fewer data sources. BP/Sohio provided information about gas production in their annual reports. All of Sohio's gas production was on the North Slope, and most of that was produced from Prudhoe Bay for use in production operations. Estimates of natural gas production in column 1 of Table I-5 are based on these data. The *U.S. Energy Statistics Sourcebook* provided data on total Alaska natural gas production. This data series is gross of royalty. Adjusting the *U.S. Energy Statistics Sourcebook* data for a 1/8 royalty and deducting the Sohio-based estimate of ANS production gives an estimate of ANS natural gas working interest production and other Alaska natural gas working interest production. The non-ANS production data computed by this method are reported in column 3 of Table I-5. These estimates were compared with AOGCC data and with data reported by the U.S. Department of Energy. The differences were not significant.

Table I-5
Natural Gas Production Estimates
Net of Royalty
(billions of cubic feet)

Year	*ANS per BP/Sohio*	*All Alaska per Sourcebook*	*Non-ANS Estimate*
1987	80.1	314.8	234.6
1986	70.4	266.7	196.4
1985	55.5	281.2	225.6
1984	41.8	253.0	211.2
1983	39.4	242.1	202.7
1982	35.8	231.3	195.5
1981	33.2	212.2	179.0
1980	48.5	201.8	153.2
1979	25.6	193.2	167.5
1978	20.5	177.7	157.2
1977	8.0	164.4	156.4
1976			145.3
1975			140.2
1974			112.8
1973			114.6
1972			110.0
1971			106.4
1970			97.6
1969			44.5

REVENUE ESTIMATES

Production data multiplied by the price per unit of production gives gross revenues. The question is how to obtain an accurate estimate of the price per barrel of ANS crude oil given that the oil is disposed of at different prices.

There are several estimates of ANS per barrel revenue which must be considered when preparing a total revenue estimate. The approach used here was based primarily on the weighted average of the reported per barrel prices given in the producers' corporate annual reports. Adjustment was made to reflect the transportation and quality differences between Kuparuk and Prudhoe Bay crude. These adjustments were based on information provided by Salomon Brothers and Barclay's.

The first set of data used were the reported per barrel prices for crude oil obtained from the annual reports of Sohio and Arco as well as the *U.S. Energy*

Statistics Sourcebook. These data are presented in columns 1 through 3 respectively of Table I-6. In 1988, Barclay's produced a report on BP which, among other things, detailed revenues at Pump Station 1 for 1985 through 1987. This information is included in column 4 of Table I-6 for comparison.

Estimates given in Table I-6 are based on overall production. It is necessary to disaggregate the data for Prudhoe Bay and for Kuparuk. Given that Arco reported production for both fields, and that its per barrel revenue is, effectively, a weighted average of the prices from these two fields, it is possible to disaggregate the prices if the difference between the two prices is known. The difference between the Prudhoe Bay price and the Kuparuk price would be due to the Kuparuk pipeline tariff and a quality differential between the two fields.

Table I-6
Per Barrel ANS Revenue Data
(Pump Station #1)

Year	*Sohio*	*Arco*	*Sourcebook*	*Barclay's*
1987		$ 10.95	$ 10.84	$ 10.74
1986	$ 7.38	6.43	6.45	6.76
1985	16.92	16.81	16.98	17.83
1984	17.78	17.11	17.91	
1983	17.73	17.31	17.69	
1982	19.97	19.08	19.92	
1981	23.86	22.65	23.23	
1980	16.79	16.95	16.87	
1979	10.72	na	10.57	
1978	4.56	na	5.21	
1977			5.84	
1976			5.02	
1975			4.92	
1974			3.62	
1973			3.23	
1972			3.17	
1971			3.01	
1970			2.90	
1969			na	

According to Barclay's, the Kuparuk pipeline tariff is $1.00 per barrel. Barclay's also estimated that the quality differential is $.50. For the years 1982 and 1983, these estimates are consistent with other sources. Therefore, the

Kuparuk price should be $1.50 per barrel less than the Prudhoe Bay price for 1982 and 1983. In 1984, the new Kuparuk pipeline was brought on stream and a new pipeline tariff established. *Petroleum Intelligence Weekly* (February 1988) and other sources indicate that the price difference between Prudhoe Bay and Kuparuk for 1982 and 1983 should equal $.95 per barrel. In later years the difference declines. The $.95 per barrel differential together with the average per barrel ANS price data were used to construct estimates of the price of crude oil for each field.

The formula for generating these estimates is developed as follows. For 1984 through 1987, Arco's average per barrel price:

$$\frac{P_{Kuparuk} \times (X - \$0.95) + P_{Prudhoe} \times X}{\text{Total Production}}$$

Where P = Production for each field and
X = Price for Prudhoe Bay

Using the formula for 1987, for example, gives the following price estimates:

$$\frac{122.0 \times (X - \$0.95) + 324.9\ X}{446.9} = 10.95$$

$$X \text{ (Prudhoe Bay Price)} = \underline{11.21}$$

$$X - \$\ 0.95 \text{ (Kuparuk Price)} = \underline{10.26}$$

Similar estimates are obtained for each other year when Kuparuk was in production.

The amounts reported in Table I-6 and the field prices obtained from the calculations discussed above provide a starting point for determining the final estimate. The per barrel revenue amounts for Arco are widely believed to be greater than for Sohio because a greater portion of Arco's ANS crude is disposed of on the U.S. West Coast and, therefore, avoids the extra cost of the longer marine voyage and trans-Panama shipment.[2] The realizations for Exxon are

[2]See Barclay's de Zoete Wedd (1988), *Petroleum Intelligence Weekly* (Feb. 1, 1988) and Salomon Brothers (1987) for discussions of the differences in dispositions.

also believed to be somewhat greater than for Sohio because Exxon's dispositions occur almost exclusively on the U.S. West Coast. For these reasons, the per barrel data given in Table I-6 probably understate actual realizations. This belief is confirmed by reports by financial analysts such as Salomon Brothers and *Petroleum Intelligence Weekly* who use higher realization prices for Arco's ANS crude.

As a result of all these factors, it appeared that the revenue number needed to be adjusted for the greater proportion of dispositions on the West Coast by producers other than Arco and Sohio. Examination of price differentials for West Coast and Gulf Coast dispositions as well as cost differences suggests that, conservatively, crude oil disposed of on the West Coast should have a value that is approximately $1 per barrel greater on the North Slope than crude oil disposed of elsewhere. Because public data are limited on the precise value of each North Slope company's crude oil, the revenue here is based on the assumption that Arco and Sohio's average disposition prices were as reported in their 10-K's and that other producers obtained an average of $1 more per barrel for their crude. The difference is presumed due to Arco's netback method. The results are more consistent with outside analysts' observations and tie more closely to the State's reported severance tax collections. The Alaska Department of Revenue's report of revenue sources states that severance tax collections totalled $10.2 billion over the period 1969 through 1987. The analysis in this report gives a total severance tax collection of $10.4 billion. The amounts are within a 2.3% margin of error.

Estimates of total revenue for Prudhoe Bay were calculated by using a weighted average price for Prudhoe Bay crude oil. It was assumed that 51% of Prudhoe Bay crude was sold at the price reported by Sohio and 21% at the price calculated for Arco. The remaining 28% of Prudhoe Bay production was

assumed to have been sold at a price that was $1 per barrel greater than that reported by Arco. This approximates the dispositions indicated in other information sources.[3] Data were available to make these calculations for the years 1980 through 1986. In 1987, Sohio was no longer in existence as a separate entity. Its successor, BP America, did not report weighted average ANS crude prices. Dividing BP America's Alaska revenues by its ANS production gives a substitute estimate. For 1978 and 1979, data limitations required use of Sohio's prices. The 1977 average price was based on the *U.S. Energy Statistics Sourcebook* because other data were not available. Comparing all of the different estimates across time, it does not appear that using different base estimates will have a significant effect on the results.

An alternate method for computing Prudhoe Bay revenue is to take Sohio's price per barrel times total production. This should provide a lower overall estimate since Sohio's price realizations are expected to be lower due to their additional transportation costs.[4] The weighted-average revenue estimate used in this report is 1.19% greater over the eleven-year production history. Given that Sohio's prices are expected to be lower, this lends further support to the assertion that the estimate used in this report is reasonably close, and probably somewhat conservative, relative to the actual revenue realized.[5]

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[3]It may be possible to derive more accurate estimates of revenue. Examination of public and private data sources indicated in the list of references suggests that the resulting revenue estimates will be somewhat greater than those reported here.

[4]The per barrel prices reported in the 10-K are different from what one would expect given that Sohio's transportation costs downstream of Valdez are higher than the costs for Arco. The reasons for this discrepancy are unknown. The *Sourcebook* data series and the Barclay's data suggest that the per barrel numbers used here are not consistently the highest nor the lowest. Moreover, the different series are usually within a few cents per barrel of each other. At best, it appears that the data are approximately consistent. It is not possible to obtain an exact estimate of these revenues.

[5]Indeed, on a weighted average basis over the life of ANS production, an estimate using Sohio's price alone should be approximately 7% lower than actual realizations.

Kuparuk revenue was based on the calculated Kuparuk price per barrel times the production estimate for Kuparuk. The Kuparuk price was estimated by taking the weighted average Prudhoe Bay price and deducting $0.95 per barrel for the years 1984 through 1987 and deducting $1.50 per barrel for 1982 and 1983. The results conform to the prices reported in such other sources as *Petroleum Intelligence Weekly*, Salomon Brothers and Barclays de Zoete Wedd (1988).

For 1977 through 1987, price data for non-ANS crude was obtained from DeGolyer and MacNaughton's *20th Century Petroleum Statistics* (1988), which is derived from U.S. Department of Energy statistics. The DeGolyer and MacNaughton data report Tier I and Tier II prices, but do not indicate how much crude was sold under either price level. For lack of any available data, it has been assumed that 1/2 was Tier I and 1/2 was Tier II. Prior to 1977, the composite published Alaska prices are directly available from the *U.S. Energy Sourcebook*. Other Alaska crude oil revenue was based on the AOGCC production data times the prices obtained from DeGolyer and MacNaughton for 1978 through 1987 and from the *Sourcebook* for prior years. There does not appear to be a substantial difference between the estimates obtained under other methods not described here.

A summary of the estimated revenues realized for Prudhoe Bay (including Lisburne), Kuparuk (including Milne Point) and all other Alaska crude oil production is provided in Table I-7. These revenue data are net of royalty. In Section III, an adjustment is made to add royalty to these revenues and then to deduct it as an expense.

Table I-7
Crude Oil Revenue Data
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Other Alaska*	*Total*
1987	$5,695	$ 942	$ 232	$6,869
1986	3,729	575	191	4,495
1985	8,600	1,145	343	10,088
1984	8,842	685	468	9,995
1983	8,823	631	539	9,993
1982	9,842	528	674	11,044
1981	11,665		873	12,538
1980	8,304		284	8,568
1979	5,136		285	5,421
1978	1,587		291	1,878
1977	631		262	893
1976			294	294
1975			329	329
1974			311	311
1973			232	232
1972			208	208
1971			218	218
1970			221	221
1969			189	189

Natural Gas. Natural gas price estimates were available for Arco for the years 1983 through 1987. Sohio presented natural gas price data for 1977 through 1986. These numbers were used to estimate revenues from natural gas on the North Slope for the years when Prudhoe Bay was in production. The numbers are relatively close in amount. A weighted average was used for the years when both Arco and Sohio published these data. The assumption was that the Arco price was attributable to 76% of the production, the Sohio price was attributable to 24%, and the missing data are proportional to these numbers. Separate data were not available for Kuparuk.

Other Alaska gas prices were based on the *U.S. Energy Sourcebook* unit prices and are shown in column 3 of Table I-8. All of the unit price data are given for comparative purposes in Table I-8.

Table I-8
Natural Gas Price Data
(dollars per thousand cubic feet)

Year	*Sohio*	*Arco*	*Sourcebook*
1987		$ 1.14	$ .50
1986	$ 1.06	1.16	.74
1985	1.06	1.28	.73
1984	1.06	1.10	.73
1983	1.97	1.03	.63
1982	2.20		.62
1981	2.08		.73
1980	1.96		.52
1979	2.00		.52
1978	2.02		.40
1977	na		.39
1976			.30
1975			.17
1974			.18
1973			.15
1972			.24
1971			.25
1970			.25
1969			.25

na. Not available.

Multiplying the unit price data from Table I-8 times the production data from Table I-5 gives an estimate of total revenues. The revenue estimates for natural gas are given in Table I-9.

A comparison of Table I-9 with Table I-7 shows that natural gas revenues are not significant in dollar terms for the Alaska North Slope. Hence, the inability to subdivide ANS natural gas revenues between Prudhoe Bay and Kuparuk will not have a meaningful effect on the analysis. By contrast, natural gas revenues are significant for the remainder of Alaska. In some years they account for more than one-half of the reported revenues.

Table I-9
Natural Gas Revenue Data
(millions of dollars)

Year	*Prudhoe*	*Other Alaska*	*Total*
1987	$ 91	$ 117	$ 208
1986	80	145	225
1985	68	165	233
1984	46	154	200
1983	49	128	177
1982	79	121	200
1981	69	131	200
1980	95	80	175
1979	51	87	138
1978	41	63	104
1977		61	61
1976		44	44
1975		24	24
1974		20	20
1973		17	17
1972		26	26
1971		27	27
1970		24	24
1969		11	11

Combining natural gas revenues from Table I-9 with the crude oil revenues reported in Table I-7 yields the total revenue estimates for each major area in Alaska. These estimates are shown in Table I-10. It is these revenue estimates that form the basis for the profit analysis which follows. To obtain profit, it is necessary to deduct expenses incurred to earn the revenues reported in this section. Estimation of these expenses is the next topic in this report.

Table I-10
Producers' Revenue Data
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Other Alaska*	*Total*
1987	$5,786	$ 942	$ 349	$7,077
1986	3,809	575	336	4,720
1985	8,668	1,145	508	10,321
1984	8,888	685	622	10,195
1983	8,872	631	667	10,170
1982	9,921	528	795	11,244
1981	11,734		1,004	12,738
1980	8,399		364	8,763
1979	5,187		372	5,559
1978	1,628		354	1,982
1977	631		323	923
1976			338	338
1975			353	353
1974			331	331
1973			249	249
1972			234	234
1971			245	245
1970			245	245
1969			200	200
Totals	**$73,523**	**$4,507**	**$ 7,889**	**$85,918**

II. PRODUCTION EXPENSES

Production expenses fall into nine major categories: depreciation, severance taxes, operating expenses, windfall profit taxes, exploration costs, overhead, interest, state and federal income taxes. Federal income taxes, severance taxes and depreciation are larger in amount relative to the other expenses. Overhead, interest and state income taxes are relatively low. The ability to estimate each of these cost categories accurately varies. The most difficult to estimate are overhead and interest. Fortunately, these are relatively small in amount. Severance taxes and depreciation are relatively easy to estimate. Federal income tax estimates depend on several assumptions. The effect of the assumptions on reported profit is tested later in this technical discussion.

Each of the expense categories and the method of determining the expense is discussed in this section.

DEPRECIATION

Depreciation represents a pro rata share of the initial cost of the investment in drilling, lease acquisition, production facilities and other similar costs over the periods or products that benefit from those investments. Depreciation expense also includes a provision for future dismantlement of the facilities and for restoration of the affected sites. Unlike most other expenses, depreciation does not require a current outlay of cash; it is a current accounting for a prior or an anticipated outlay.

There were three company sources for estimates of depreciation on the Alaska North Slope: (1) BP America's 1987 annual report, (2) Sohio's annual reports from 1977 to 1986, and (3) Arco's 10-K's. In addition, the public data reported here were compared to Alaska property tax information. The results

suggest that use of private data would tend to support the findings reported here. The data and the limitations of the data from each source is addressed in turn.

In its 1987 Annual Report, BP America provided an estimate of its 1986 and 1987 Alaska depreciation which, when divided by its Alaska production, gave a per barrel depreciation amount. However, when BP purchased the outstanding shares of Sohio, it paid a premium over the book value of the assets of Sohio. BP added this premium to its asset base and depreciated this premium along with the cost of the assets. As a result, BP America's Alaska depreciation reflects not only a portion of the costs actually incurred in Alaska, but an additional amount which reflects payments to Sohio shareholders. This latter amount was not part of the cost to acquire oil producing facilities in Alaska. Rather, it reflects BP's purchase of shares from Sohio stockholders. The amortization of this cost is not a cost of operating BP America's Alaska properties, but rather is a transfer payment.[6] As a result, BP America's depreciation numbers overstate amortization of the costs incurred in Alaska and would understate profit.

In its annual reports for 1981 to 1986, Sohio provided a per barrel total production cost amount with and without depreciation. Subtracting the reported production costs without depreciation from production costs with depreciation yields the depreciation per barrel for Alaska production.

Certain of Arco's 10-K reports stated its depreciation charge for Alaska production activities as a total dollar amount. Dividing these amounts by each year's Alaska production volumes gave an estimate of Arco's per barrel Alaska depreciation. This is referred to below as the Arco production-based estimate.

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[6]See Barclay's de Zoete Wedd 1988 report on British Petroleum, p. 4, for the reasons why BP was willing to pay a premium for the remaining outstanding shares of Sohio.

Arco's 10-K also gave its Alaska producing property plant and equipment. When these amounts were divided by Arco's proved reserves each year, an alternate estimate of per barrel depreciation was obtained. This is referred to as Arco's reserve-based estimate. These are composite estimates for all Alaska production, so that adjustments are necessary to obtain estimates for crude oil for each significant field. The alternate estimates are given in Table II-1.

Table II-1
Unit Depreciation Data
($ per equivalent barrel)

			Arco	
Year	*BP America*	*Sohio*	*Production*	*Reserves*
1987	$ 2.83		$ 2.21	2.49
1986	2.26	$ 2.15	2.56	2.62
1985		1.51	2.47	2.47
1984		1.34	1.65	2.17
1983		1.14	1.81	1.92
1982		1.11	1.56	1.73
1981		1.07	1.30	1.23
1980		1.05		.96
1979		.90		
1978		.84		

These depreciation numbers reflect a weighted average of both Kuparuk and Prudhoe Bay. It is generally recognized that Prudhoe Bay depreciation is lower than Kuparuk. For example, Barclay's de Zoete Wedd (1988) reported Prudhoe Bay depreciation in 1987 at $2.00 per barrel and Kuparuk at $3.80. If Barclay's estimates are correct, and assuming that Arco's depreciation is approximately equal to Sohio's, Arco's 1987 weighted average depreciation per barrel should equal:

$$\frac{\$3.80 \times 122 + \$2.00 \times 340}{122 + 340} = \$2.475$$

where 122 and 340 represent Arco's daily average production from Kuparuk and Prudhoe Bay (plus Lisburne) fields as shown in Table I-1, above. Based on this calculation, $2.475 should be the weighted average per barrel depreciation shown in Arco's annual reports. However, Table II-1 suggests that Arco's

weighted average depreciation is about $2.21 to $2.49. Averaging these two estimates gives $2.35, which is probably the best estimate of Arco's North Slope production depreciation available from Arco's financial statements.[7] This suggests that the $3.80/$2.00 estimates of depreciation for each field are too high.[8]

Given that Sohio's weighted average depreciation number for 1986 was $2.15 and that was an average of the lower-depreciation Prudhoe Bay and the higher-depreciation Kuparuk, it is likely that Arco's 1986 Prudhoe Bay depreciation was no more than $2.15 per barrel. This amount is slightly higher than the Barclay's estimate. Presumably, Sohio's depreciation for Prudhoe Bay alone would be lower than $2.15, so the basis used here could result in an understatement of profit. Assuming Prudhoe Bay depreciation is $2.15 per barrel, then we can solve for Kuparuk using the equation:

$$462 \times \$2.35 = 122\,X + 340 \times \$2.15$$

$$X = \underline{\$2.91}$$

This equation states that Arco's weighted average depreciation per barrel ($2.35) should equal the Kuparuk production times the unknown depreciation for Kuparuk plus the estimated $2.15 per barrel depreciation for Prudhoe Bay. The result suggests a $2.91 per barrel depreciation estimate for Kuparuk.

If Kuparuk depreciation is $2.91 per barrel, then Prudhoe Bay depreciation per barrel for the years when Kuparuk and Prudhoe Bay were both in production is as given in Table II-2, below. The numbers in Table II-2 should be compared

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[7]Salomon Brother's financial analysis of Arco's operations states that Arco's Alaska depreciation is lower than Sohio's. This is the opposite of the data from the financial statements. Public data are not available which would enable us to resolve this disparity. The data in this report are based on the higher estimate from the 10-K's, even though this may overstate depreciation and understate profit.

[8]Salomon Brothers Inc. reported an estimate of $1.60 per barrel 1985 depreciation for Prudhoe Bay and $1.75 for 1987. They reported 1985 Kuparuk depreciation at $3.75 per barrel and 1986 at $3.55 This confirms the suggestion that Barclay's Prudhoe Bay depreciation is too high. The effects of alternate depreciation estimates on the reported profit for each field are discussed in Section III.

with other sources. For example, *Petroleum Intelligence Weekly* estimated Prudhoe Bay depreciation at $2.25 in 1987, $2.17 in 1986 and $1.53 in 1985. Salomon Brothers estimated Arco's Prudhoe Bay depreciation at $1.80 in 1987, $1.75 in 1986 and $1.60 in 1985.

Table II-2
Estimated Prudhoe Bay Depreciation
($ per barrel)

Year	*Amount*
1987	$ 2.15
1986	2.25
1985	1.75
1984	1.44
1983	1.29
1982	1.19
1981	1.05
1980	.98
1979	.78
1978	.73
1977	.38

These data are higher than Sohio's reported weighted average depreciation charges, but appear more reasonable than the Barclay's numbers. The numbers are lower than Arco's weighted average, which is consistent with expectations. Moreover, they are higher than the Salomon Brothers numbers. In brief, depreciation based on these numbers is a "middle-of-the-road" approximation.

Since depreciation expense for each field was computed using a weighted average based on working interest production from each field, total depreciation for both fields taken together will be approximately the same. That is, Prudhoe Bay might be assigned too much depreciation as a result of this process, but that will be offset by lower depreciation charges to Kuparuk. The "bottom-line" effect of this is discussed in Section III.

Prior to the start of Kuparuk production, depreciation estimation is simplified. For each of the years 1978 through 1981, a weighted average of the reported per-barrel depreciation numbers for Arco and Sohio was used. There was one