

ALASKA LEGISLATURE COMMITTEE FILES 1993-1994 8672

8052 HOUSE RESOURCES

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Table 7
 Oil & Hazardous Substance Release Response Fund
 DEC Staff Position Funding
 (as of June 8, 1992)

<u>OHSRRF Funded (%)</u>	<u>No. Pos.</u>	<u>Pos. Vacant</u>	<u>Vacancy (%)</u>
100% OHSRRF	65	9	14%
75-99% OHSRRF	13	1	8%
50-74% OHSRRF	14	0	0%
25-49% OHSRRF	33	2	6%
< 25% OHRSSF	88	4	5%
TOTAL	213	16	7.5%

Source: DEC spreadsheet "SPAR FY 93 Positions Funded by OHSRRF" June 8, 1992

Table 8
Oil Spill Prevention and Response Program
Performance Objectives

Performance Objective	FY 90 Actual	FY 91 Actual	FY 92 Actual	FY 93 Request
Spill Drills	7 (a)	71 (b)	101 (e)	106 (c)
C-Plan Review/Approval*	53 (a)	97 (d)	79 (e)	183 (c)
Facility Inspections	n/a	112 (d)	139 (e)	142 (c)
Vessel Inspections	n/a	75 (d)	98 (e)	73 (c)
Financial Responsibility	450 (a)	475 (d)	350 (e)	475 (c)
Respond Oil/HazMat Spills	300 (a)	450 (d)	701 (e)	875 (c)
Enforcement Actions (for spills greater than 10,000 gal)	24 (a)	15 (d)	87 (e)**	15 (c)

- (a) FY 92 B3/B4 BRU Environmental Quality Projects Strategy and Performance Plans.
 (b) OHSRRF Annual Report for Fiscal Year 1991. The level of drills varied ranging from "tabletop" or telephone drills to actual deployment and operation of response equipment.
 (c) FY 93 Spill Prevention and Response B3/B4 "BRU Strategy Performance Plans" (11/15/91).
 (d) Estimated from FY 91 "current year plan" as reported in FY 92 B3/B4 BRU Environmental Quality Projects Strategy and Performance Plans.
 (e) Larry Deitrick/DEC Government Preparedness and Response, personal communication.
 * Includes C-plan reviews for OCS facilities.
 ** The apparent increase in enforcement actions is attributable to a broad definition of "enforcement" to include all types of enforcement activity ranging from Notice of Violation to actual enforcement.
 n/a Not available.

Sources:

- OHSRRF Annual Report for Fiscal Year 1991.
 FY 92 B3/B4 BRU Environmental Quality Projects Strategy and Performance Plans
 FY 93 Spill Prevention and Response B3/B4 "BRU Strategy Performance Plans" (11/15/91).

Table 9
FY 93 OHSRRF Agency RSAs

Agency	FY 93 Request	Actual FY 93 RSA
Military & Veterans Affairs	\$ 5,000,000	\$ 800,000
Fish & Game	258,000	202,200
Health & Social Services	161,500	7,500
Natural Resources	108,704	28,900
Law	3,653,100	3,383,000
Labor	4,000	5,000
Community & Regional Affairs	11,000	5,000
 TOTAL	 \$ 9,196,304	 \$ 4,431,600

Table 10
Emergency Response Depots & Corps
OHSRRF Appropriation History

Fiscal Year	Appropriation	DEC Response Office Expend/Encumb	DMVA Depots & Corps Expend/Encumb	Lapsed Funds
FY 90	\$3,909,900	\$349,425	\$ 0	\$3,560,475
FY 91	3,169,900	883,646	203,520	2,082,734
FY 92	2,911,400	441,126	324,930	n/a
FY 93	800,000 *	n/a	n/a	n/a

n/a — Not available.

* In addition to these funds, a separate appropriation of \$1.2 million was made to DEC for the nearshore strike team demonstration project.

Source:s

OHSRRF Annual Report, Fiscal Years 1990 and 1991.

Division of Legislative Audit, Audit Number 18-4429-92 (March 17 1992)

Table 11
Future OHSRRF Revenue
from the Nickel-per-Barrel Surcharge
Mid-Range Production Forecast
(\$ million)

FY 93	26.7
FY 94	26.5
FY 95	26.0
FY 96	24.8
FY 97	22.7
FY 98	20.6
FY 99	18.3
FY 00	16.1
FY 05	9.4
FY 10	5.1
FY 15	3.3

Source: DEC "A Strategic Plan for the Oil and Hazardous
Substance Release Response Fund" (April 1992)

California adopts tough spill law

25-cent per-barrel tax finances \$100 million oil-spill cleanup fund

By JERRY GILLAM
Los Angeles Times

SACRAMENTO — Saying "an ounce of prevention would certainly be worth a barrel of spilled crude oil," California Gov. George Deukmejian on Saturday signed into law the most comprehensive offshore oil-spill prevention and cleanup plan in the nation.

In his regular weekly radio address, the governor said the new law "will give California an unprecedented ability to prevent spills before they happen and to fight the effects of spills if they do occur."

The statute, which takes effect immediately, is a direct result of the Exxon Valdez oil spill in Alaska last year and the British Petroleum tanker spill off Huntington Beach, Calif., in February.

Generally viewed as one of the major achievements of the recently concluded legislative session, it

would create a \$100 million oil-spill cleanup fund to be financed by placing an additional tax of 25 cents on each barrel of oil, which is expected to add less than a cent per gallon of gasoline sold at the pump.

In the event of a spill, the state also would be given unlimited authority to borrow additional funds for cleanup operations that would be repaid by the oil companies.

The governor is given the power to appoint a state oil-spill "czar" or response administrator who will be charged with setting up a detailed comprehensive plan for the safe transportation of oil along California's coast.

These steps are expected to include surprise inspections of tankers and terminals, up-to-date safety plans for refineries, use of radar for tanker traffic, and requiring tugboat escorts in hazardous waters.

Oil companies transporting

their product through state waters also must be able to demonstrate that they have \$500 million worth of oil-spill liability insurance protection.

For the first 60 days following a spill, cleanup crews will be immune from lawsuits for property damage they may cause. Oil industry representatives contend immunity from liability for professional cleanup crews is necessary because they must act quickly to prevent the spill from spreading and should not be inhibited by fears they might get sued.

In his radio speech, Deukmejian said: "As everyone knows, the price of an oil spill is measured not only in miles of polluted beaches, but also in the tax dollars that must be expended to clean up the mess.

"In the case of oil spills, an ounce of prevention would certainly be worth a barrel of spilled crude oil."

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Gen. Info.

File 3

The Revenue Side of the Budget Equation: How We Gave Away Up To
Ten Years of General Fund Revenues Without Even Noticing It, and
What To Do About It Now

Remarks of Richard A. Fineberg to Common Ground
March 13, 1993

Summary

Production: Although Prudhoe Bay has entered its decline, State forecasts consistently under-estimate and then revise upwards estimated future production figures. Thus, between 1985 and 1992 there was a 27.6% increase in total North Slope production forecasted through 2010. At the same time, the still-undefined date of shutdown has been moving away from us almost as fast as we approach.

Despite clear indications that ARCO intends to produce from the West Sak field when Kuparuk slows down, State forecasts slashed forecasted West Sak production between 1990 and 1992.

Profits: Estimating North Slope profits requires gathering and integrating data from a variety of sources. The result is an estimated 1991 after-tax profit from Alaska production and pipeline operations of \$4.77 per barrel. If that production were controlled by one company, that firm would have been among the three most profitable firms on the Fortune 500 in 1991.

Using the same methodology, North Slope estimated profits in FY 2000 (at one million barrels per day without West Sak) would still rank among the ten most profitable corporations in the nation.

Arctic National Wildlife Refuge production would produce about \$0.98 per barrel less revenue for the State than an equivalent barrel of oil from State land near Prudhoe Bay.

Settlements: The secrecy associated with revenue dispute settlements can have serious repercussions. For example, a little-noticed provision of the 1985 TAPS settlement that was portrayed as revenue neutral will actually produce an off-book or hidden profit to the TAPS owners estimated at \$12 to \$22 billion in 1992 dollars.

To ensure effective oil and gas policy and reduce the likelihood of such mistakes in the future:

(1) The Legislature should require by law an annual audit and report on all major tax, royalty and pipeline disputes;

(2) A statute should be enacted proscribing any settlement from extending confidentiality beyond that currently required by law;

(3) To place pipeline tariff management in its appropriate administrative context, authority for inter-state tariff matters should be transferred from the Department of Law to an agency with a statutory resource or revenue management mandate; and

(4) The Governor should establish an inter-agency working group whose first task should be to establish a mechanism for independent review of all major oil and gas revenue settlements.

Thank you for the opportunity to participate with and address you in your deliberations on the future of state government. It's a pleasure to be here today, and to share the platform with such knowledgeable veterans of the oil industry and public service. I hope the information I have tried to put together will prove as worthy of your time as the expertise of these extraordinarily well-informed and competent individuals.

At this luncheon session of this two-day gathering, we are considering the revenue side of the budget equation. Since this portion of the State budget is too often treated as a given or overlooked altogether, I think you were wise to include this item on your agenda. I'm going to base my talk on two reports I prepared in late 1992 on the remarkable profitability of North Slope oil operations. I believe you have received the executive summaries in your information packets.¹ To this date, I am aware of no significant substantive challenges to thrust or the bottom line of the information presented in either report.

Let me make it clear at the outset: I am not here to advocate higher taxes on the oil industry. I am suggesting two things:

(1) There is a need for better understanding of the enormous production potential and profitability of North Slope operations to evaluate intelligently both taxation and environmental policy options.

(2) There may be opportunities to enhance our revenues by avoiding inadvertent revenue losses through relatively simple statutory and administrative changes in the way we conduct and execute our policies.

¹ Richard A. Fineberg, Hidden Billions: The TAPS DR&F Provision (report prepared for Stan Stephens, August 21, 1992) and North Slope Profits and Production Prospects (report prepared for the Alaska State Senate Finance Committee, Nov. 12, 1992). All tables and graphs I am presenting today are taken from these reports.

Although the super-giant Prudhoe Bay field has entered its decline, the rate and importance of North Slope decline may be exaggerated. It is a matter of fact — not speculation — that State forecasts typically underestimate and then revise upwards future production figures. The first slide breaks North Slope production into three time periods: 1977-84, 1985-91 and 1992-2010. The three periods are summed in the right-hand column. Our focus is the third column. I break off in the year 2010 so that the data can be compared with other forecasts that may cut off at different time, and because estimates that far in the future are highly dependent upon assumptions about the price of oil, inflation and other factors that are essentially unknowable. Note in the totals that there is a 27.6 percent increase between the 1985 and 1992 forecasts of total production, and that most of that increase is due to increases in the third column — production forecast totals between 1992 and 2010.

At the same time, the much-discussed but still undefined date of North Slope shutdown has been moving away from us, almost as fast as we approach. In 1985, for example, the state estimated that the last time we would see one (1.0) million barrels of oil per day through TAPS would be 1994 — next year. Seven years later, in 1992, the forecast indicates that we'll be producing over 1.6 million barrels per day in 1994. Now it is estimated that we won't cross the one million barrel level until the year 2001. While the 1992 production level represents a drop of nearly 20 percent from the North Slope peak achieved in 1988, at the same time the 1992 production level was almost identical to that of 1985. Back in 1977, Prudhoe was expected to start declining by 1985 — year eight of North Slope production. In year fifteen, we were still at the level originally anticipated for year eight, and State forecasters estimate we'll be at that level for two more years.

Changes in ANS Production Forecasts, 1985-1992

/===== Total ANS Production (all fields) =====/

	<i>(actual 000 bbls.)</i>	+	<i>(forecast and/or actual 000 bbls.)</i>	+	<i>(forecast 000 bbls.)</i>	=	<i>(forecast + actual 000 bbls.)</i>
<u>Year of Forecast:</u>	<u>1977 - 1984</u>		<u>1985 - 1991</u>		<u>1992 - 2010</u>		<u>Total (1977-2010)</u>
1985	3,894,105		4,210,185		4,066,100	=	12,170,390
1988	3,894,105		4,781,704		4,427,815	=	13,103,624
1989	3,894,105		4,838,996		4,928,230	=	13,661,331
1990	3,894,105		4,723,021		5,823,575	=	14,440,701
1991	3,894,105		4,801,909		6,506,762	=	15,202,776
1992	3,894,105		4,780,297		6,857,985	=	15,532,387
% increase over							
1985 forecast:	0.00%		13.54%		68.66%		27.62%

Source : 1977-84 from Dept. of Natural Resources, "Historical and Projected Oil & Gas Consumption," January 1985, p. 13;
1985-2010 from 1992 and previous issues of same publication.

The following table demonstrates that the lion's share of the increase in production is at Prudhoe Bay and Kuparuk — the two largest fields in North America. Forecasts are consistently revised upwards because of three factors: (1) the fecundity of major North Slope fields, (2) improved recovery technology such as horizontal drilling, fracing, miscible injectant and WAG processes and (3) the conservatism that is rightly inherent in forecasting.

After an extended look at North Slope production techniques, in 1989 the Congressional Office of Technological Assessment erroneously concluded that we had ascended the Arctic learning curve and should expect no further increases in North Slope production. In fact, in the relatively stable price environment since 1989, by 1992 we had added another 14 to 15 percent to North Slope production totals. The 1992 increase was smaller than previous years. Whether this is because the 1992 forecast fell on the back side of the Middle East war, or because OTA's bleak assessment is finally coming to pass, I cannot tell you.²

But I can tell you this: With production declining, the trend of increased future production (i.e., decreasing decline) becomes increasingly important. 1992 state forecasts show Kuparuk dropping from a current level of 300,000 barrels per day to 150,000-175,000 barrels in 2000. But last year both ARCO and BP told their stockholders that Kuparuk production is likely to hold at current levels until the end of the decade. If the company information is accurate, you can add 125,000 barrels per day to the State forecast totals for the year 2000.

I think you can count on this additional production with or without Kuparuk, because the industry has a backup in case they're wrong about Kuparuk (their history, too, is one of under-estimation and

² See North Slope Profits and Production Prospects at Table 9, p. 22 for a 1989-92 field-by-field comparison. For an earlier discussion of the reasons for this trend, see Richard A. Fineberg, An Overview of North Slope Production Prospects, 1990-2010 (report prepared for the Legislative Budget and Audit Committee of the Alaska State Legislature, December 15, 1990).

**1985 v. 1992 State North Slope Production Forecasts by Field
(for 1992 through 2010)**

<i>Field:</i>	<u>1985 Forecas</u>	<u>1992 Forecast</u>	<u>1992 v. 1985</u>
	<i>/ = = million bbls., 1992-2010 = = = /</i>		<i>% increase (decrease)</i>
Prudhoe Bay	2,436.4	4,615.8	89.4%
Kuparuk	523.8	1,033.0	97.3%
Lisburne	206.2	86.1	(59.2%)
Pt. McIntyre	0.0	305.9	n.a.
Endicott	246.4	257.7	4.5%
Milne Pt.	16.4	96.4*	487.8%
Niakuk	0.0	60.2	n.a.
W. Sak / Beaufort	636.9	403.0	(36.7%)
Total	4,066.1	6,858.0	68.7%

* Milne Pt. 1992 estimate includes Schrader Bluffs production.

Source: Dept. of Natural Resources, "Historical and Projected Oil and Gas Consumption," January 1985 and April 1992 (tables 1 and 6, above).

upward revision). It's called West Sak, a reservoir that contains at least 20 to 25 billion barrels of oil in place directly above Kuparuk and Milne Point, near Prudhoe Bay. While West Sak nearly equals Prudhoe Bay in volume, industry observers have tended to write off the possibility of Prudhoe-scale production from West Sak due to the sandy content and relatively high viscosity of its oil.

Some of you may recall that ARCO shut down its West Sak pilot project in 1989 after the state closed the ELF loophole. At that time both ARCO and BP claimed that closing the tax loophole would cause capital to dry up, thus slowing North Slope development significantly. In fact, investment in Prudhoe and Kuparuk have continued, and some of the projects that were supposed to be shut down by ELF have gone into development as if the tax structure were never changed. But ARCO did shut down its West Sak operation, leaving the public guessing as to its intentions.

While ARCO, which controls the major portion of West Sak, is busy claiming that West Sak cannot be produced economically at current prices, Conoco quietly started producing from its portion of West Sak, the Schrade Bluffs formation, which lies directly above its Milne Point reservoir. This despite the fact that Conoco's West Sak oil has two handicaps compared to ARCO: Conoco lacks ARCO's potential volume and Conoco must pay more than \$1.50 per barrel in additional pipeline charges — \$0.78 for the Milne Point pipeline tariff between the Conoco field and the main production area and approximately \$1.10 per barrel that the TAPS owners receive in profit from shipments through that line. Does Conoco know something that ARCO doesn't? Given ARCO's consistently impressive exploration record in Alaska, this seems unlikely. If Conoco can produce West Sak despite its handicaps, it seems likely that ARCO will produce West Sak when better (more profitable) oil is no longer available to it.

What I believe is happening is this: West Sak's future is tied to Kuparuk because ARCO hopes to produce West Sak by using Kuparuk facilities, thereby avoiding the capital costs of building new

cleaning and gathering plants.³ But Kuparuk facilities are operating at full capacity. This means that West Sak will have to wait until Kuparuk slows down. In the meantime, West Sak is uneconomic. Translation: ARCO has a better (cheaper) source of oil at this time.

Despite indications that Kuparuk will continue producing at current levels and that West Sak is likely to be produced as Kuparuk facilities become available, State forecasts show sharp declines at Kuparuk and no corresponding production increase from West Sak. One reason for omissions of this sort is the inherent conservatism of forecasting. I believe a more important cause may be that North Slope forecasts often fail to reflect important facts about the reason that oil companies produce oil: profit. I want to turn now to what may be Alaska's best-kept secret: The enormous profitability of the North Slope.

The following table, also taken from my November report to the state Legislature, identifies the elements of profit in Alaskan oil operations. It does not include profits on marine transportation, refining or marketing, off-book profits which I'll discuss later or the intangible value to the owners of having a stable supply of crude oil for their refineries. To get the per-barrel profit estimate at the bottom of the page — \$4.77 per barrel in calendar year 1991 — I had to work with five different institutional data sources. They are identified by the numbers circled at the right — three state agencies, trade sources and a fifth source for a federal tax rate. In fact, it took many more than five sources to generate this table. Much of the best information is shielded by confidentiality statutes. Some of the public approximations used here are not published but are available if you know where to look, or whom

³ In December 1991 ARCO officials told the Wall Street Journal that because of its marginal economics, the company did not want to produce West Sak until Kuparuk facilities were available. In June 1992 ARCO executive vice president James A. Middleton was quoted in the AAPG (American Association of Petroleum Geologists) Explorer saying that daily production from West Sak will probably peak at 100,000 to 150,000 barrels of oil per day. (See North Slope Profits and Production Prospects, pp. 16-17.)

to ask. The integration of the data into a comprehensive picture of North Slope profits requires understanding of the terms to make sure that each piece of data provided by different agencies is compatible with the other pieces. While the math is simple, the trick is to set up the table and locate data that will produce realistic results. If you have specific questions, I'll be happy to talk to you, as time permits, about how I assembled these numbers and why I think they're a fair approximation of reality.

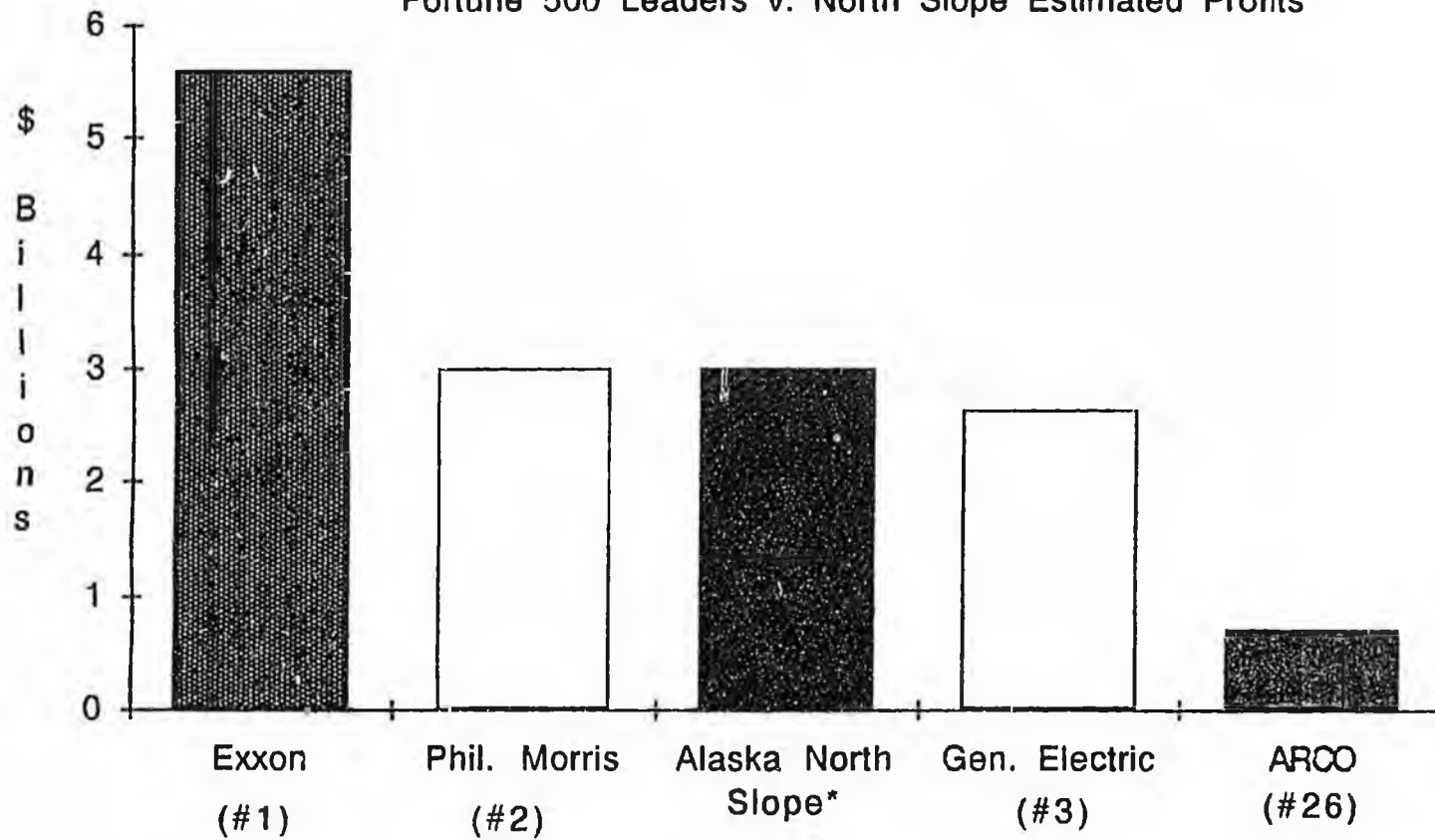
When you put the pieces of this puzzle together, you find that if ANS production and transportation were the province of one company -- instead of the three that control more than 90% of North Slope operations -- in 1991 that company would have ranked among the top three most profitable companies on the Fortune 500. Perhaps even more surprising than the results is the difficulty one has in answering the seemingly simple question: What is the value to the North Slope producers of producing ANS crude oil and shipping it through TAPS?

CY 1991 North Slope Barrel Profit Analysis (Table 12-A)

North Slope Profit Analysis - ALL FIELDS		1991 CY 91 ANS Avg. (\$/bbl.)		Notes
		Gulf Coast	West Coast	
1	Average Price for ANS (Spot)	\$18.35	\$17.21	Dept. of Revenue data (1)
2	Quality Adjusted Price			
3	Production / Disposition	<i>Bbls./year</i>	<i>Day</i>	
a	Production (mm bbls. yr. / day)	664.870	1.822	DNR 1992 Historical Oil Production (incl. NGL's) (2)
b	Volume to East / West Coast (%)	21.93%	78.07%	From DOR data
4	Feeder Pipeline Tariffs	(\$0.10)	(\$0.10)	Wghtd. avg. sum of items 4a thru 4g (3)
a	Operating & capital costs	(\$0.04)	(\$0.04)	Dept. of Law (7/29/92) less 4b
b	State & local property tax (pipelines)	\$0.00	\$0.00	30% of total DOR property tax
c	State income tax (pipelines)	\$0.00	\$0.00	4d * (eff. state tax rate / eff. fed. tax rate)
d	Federal income tax (pipelines)	(\$0.01)	(\$0.01)	Dept. of Law (7/29/92) less item 4c
e	After-tax margin	(\$0.02)	(\$0.02)	Dept. of Law (7/29/92)
f	Recovery of deferred return	(\$0.01)	(\$0.01)	.
g	DR&R allowance	\$0.00	\$0.00	.
5	TAPS Pipeline Tariff	(\$3.41)	(\$3.41)	Sum of items 5a thru 5h
a	Operating & capital costs	(\$1.31)	(\$1.31)	Dept. of Law (7/29/92) less 5h
b	State & local property tax (pipelines)	(\$0.15)	(\$0.15)	30% of total DOR property tax
c	State income tax (pipelines)	(\$0.09)	(\$0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d	Federal income tax (pipelines)	(\$0.65)	(\$0.65)	Dept. of Law (7/29/92) less item 5c
e	After-tax margin	(\$0.49)	(\$0.49)	Dept. of Law (7/29/92)
f	Recovery of deferred return	(\$0.64)	(\$0.64)	.
g	DR&R allowance	(\$0.08)	(\$0.08)	.
b	Pumpability Charge			Dept. of Revenue data
6	State Share (Feeder Lines)	(\$0.01)	(\$0.01)	Sum of items 4b, 4c
7	Federal Share (Feeder Lines)	(\$0.01)	(\$0.01)	Item 4d
8	Industry Profit (Feeder Lines)	\$0.03	\$0.03	Sum of items 4c, 4f
9	State Share (TAPS)	(\$0.25)	(\$0.25)	Sum of items 5b, 5c
10	Federal Share (TAPS)	(\$0.65)	(\$0.65)	Item 5d
11	Industry Profit (TAPS)	\$1.13	\$1.13	Sum of items 5c, 5f
12	Tanker (to Gulf / West Coast)	(\$3.83)	(\$1.07)	USFRA data (DOR)
13	Wellhead value	\$11.02	\$12.64	Sum of items 1, 4, 5, 12
14	State Royalties, Production & Property Taxes	(\$3.01)	(\$3.41)	Sum of items 14a thru 14d
a	Royalty	(\$1.30)	(\$1.50)	Item 13 less field costs * est. field royalty
b	Severance tax	(\$1.31)	(\$1.51)	Item 13 * 875 * normal severance * ELF
c	Spill Response & Conservation Taxes	(\$0.05)	(\$0.05)	\$0.054 * 875
d	State & local property tax (production)	(\$0.36)	(\$0.36)	70% of total DOR property tax
15	Production costs	(\$3.49)	(\$3.49)	Sum of items 15a, 15b
a	Lifting Costs	(\$1.19)	(\$1.19)	Derived from trade publication estimates (4)
b	Depletion, Depreciation & Amortization	(\$2.30)	(\$2.30)	Derived from trade publication estimates
16	Net Revenue (production)	\$4.52	\$5.74	Sum of items 13, 14, 15
17	State Income Tax (production)	(\$0.15)	(\$0.15)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18	Federal Income Tax (production)	(\$1.40)	(\$1.79)	Est. 32.1% of items 16 + 17 (5)
19	Industry Profit (production)	\$2.96	\$3.79	Sum of items 16 thru 18
20	Total State Share (production + pipelines)	\$3.42	\$3.82	Sum of items 6, 9, 14, 17
21	Total Federal Share (production + pipelines)	\$2.06	\$2.45	Sum of items 7, 10, 18
22	Total Industry Profit (production + pipelines)	\$4.12	\$4.95	Sum of items 8, 11, 19
23	CY 91 Industry Avg. per-barrel ANS Profit		\$4.77	

CY 1991 Estimated Profits

Fortune 500 Leaders v. North Slope Estimated Profits

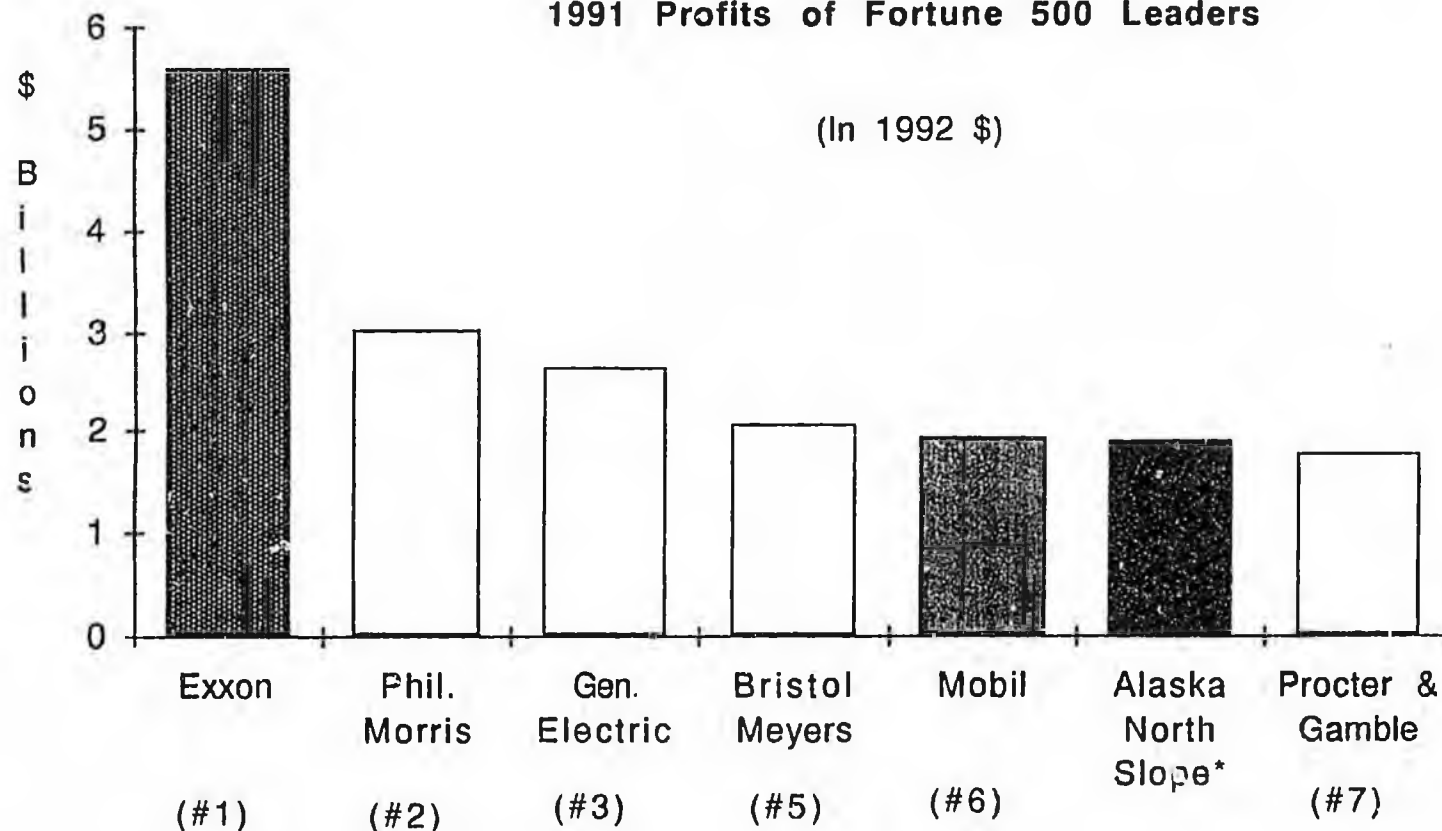


* Principally Exxon, ARCO and BP (BP is not listed in Fortune 500)

Sources: Fortune, April 20, 1992; Table 12-A

We all know production is declining. What kind of profits will the North Slope be generating in the year 2000? Once I had gathered the data to build this table, putting in the forecast numbers for the year 2000 and cranking out the model one more time was relatively simple. Nobody knows what the top companies in the year 2000 will look like — for example, who would have thought in 1985 that by 1991 perennial leaders such as IBM would be mega-losers? So I compared North Slope earnings in the year 2000 to the income of the 1991 profit leaders. And guess what? In the year 2000 forecasted North Slope production, still at one million barrels, generates enough profit that the North Slope would rank among the ten most profitable corporations in the nation. That's with Kuparuk cut in half and no West Sak replacement.

Estimated FY 2000 North Slope Profits
 v.
 1991 Profits of Fortune 500 Leaders



* Principally Exxon, ARCO and BP

Sources: Fortune, April 20, 1992; Table 15-A

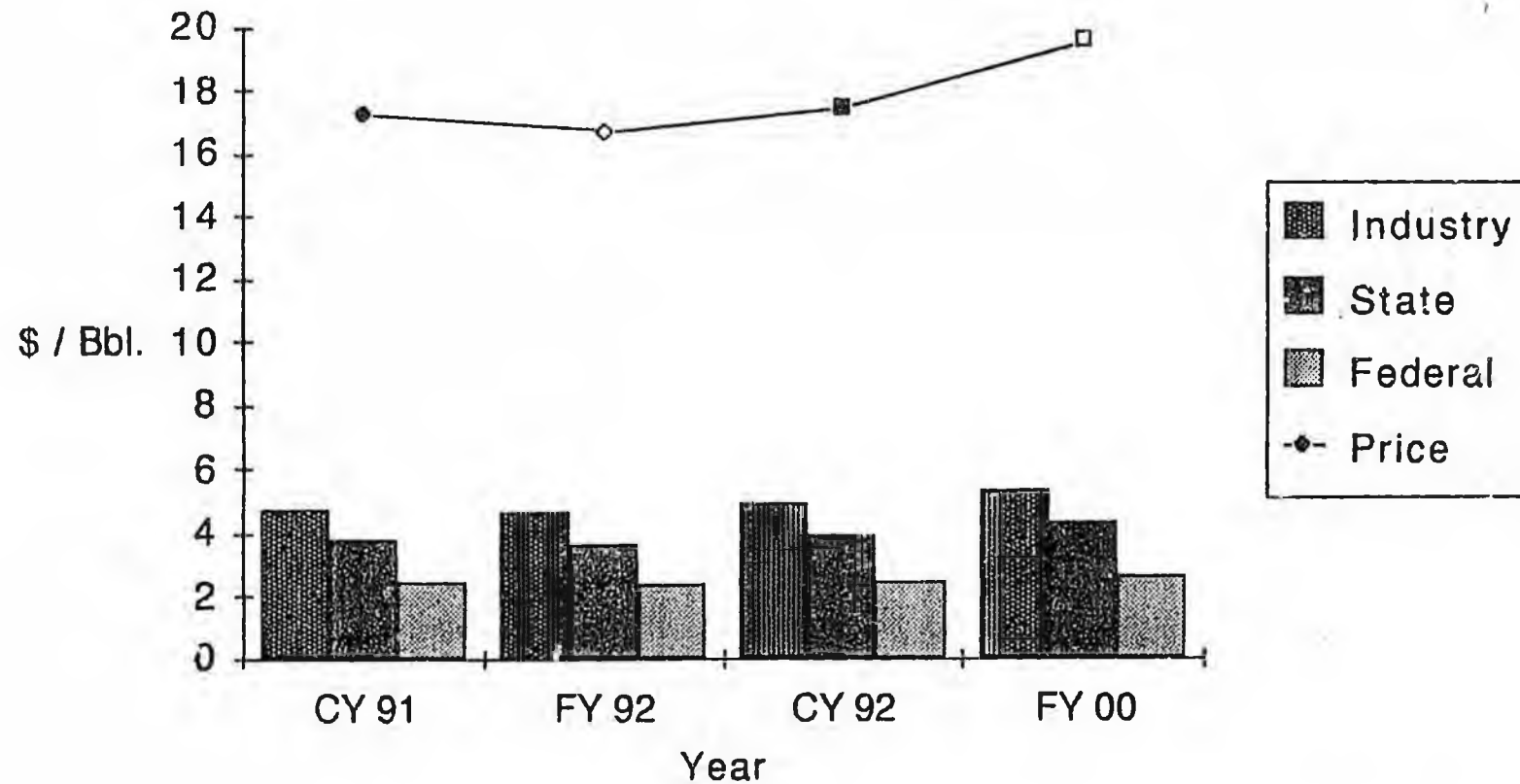
In the last two weeks you've probably seen ARCO's latest advertisement (this one has, of all things, a big, green toad) and heard BP's pitch to the Legislature. Both are heralding a North Slope turn-around and linking a continuation of the North Slope's strong showing to a stable tax climate (read: no tax increases). In my estimation, the only turn-around has been in the public relations campaigns of the oil companies. Last year, Alyeska's departing President was busy warning that excessive environmental regulation was going to kill the Golden Goose. The industry's media moguls were so pessimistic that their dire warnings apparently freaked out some Alaskans. So BP reversed gears and began running ads assuring Alaska that "we're still here." When you look at the profit margins on North Slope production, it is perfectly obvious why these guys are sticking around — and it's not because we're kind enough to encourage toads, as ARCO would now have us believe.

The following table summarizes industry, state and federal income from Alaska oil operations, again including pipelines and excluding West Sak production. These are conservative figures, if only because it is difficult to imagine what set of circumstances — other than a similar quantity of cheaper, better oil from another source — would prevent ARCO from putting West Sak into production.

If this information seems relevant to you as connoisseurs of public policy, then you might want to ask yourselves: Why aren't we generating this information for public consumption in the normal course of revenue and resource management?

Should the information lead you to consider oil tax revisions, several observations are in order: First, the State should retain specialists to assess the implication of different taxing mechanisms. It is probable that tax revisions should speed the payback of development costs on a field by keeping taxes low until the development is paid off. Similarly, a tax change at the top end should be instituted to cap profits.

West Coast ANS Prices and Economic Rents CY 91 - FY 2000 (Selected Years)



CY 1991 (\$17.21 / Bbl.)

FY 1992 (\$16.64 / Bbl.)

CY 1992 (\$17.42 / Bbl.)

FY 2000 (\$19.54 / Bbl.)
(in 1992 \$)

Industry Share \$4.77 (43.2%)

\$4.67 (43.9%)

\$4.92 (43.9%)

\$5.34 (43.7%)

State Share \$3.82 (34.6%)

\$3.65 (34.3%)

\$3.85 (34.4%)

\$4.30 (35.2%)

Federal Share \$2.45 (22.1%)

\$2.31 (21.7%)

\$2.43 (21.7%)

\$2.59 (21.2%)

Source: Tables 12-A, 13-A, 14-A, 15-A

From this perspective, I want to turn now to the economics of production from the Arctic National Wildlife Refuge. The following table uses the same methodology described above to determine the state's share of Arctic Refuge production. In presenting this table I'm correcting one part of the analysis in my report to the Alaska State Legislature. Subsequent to 1986, the Department of Interior's 1002 report described the mean-case field at 3.2 billion barrels. The Department of Revenue did an in-house estimate of Arctic Refuge tariffs — never published, to my knowledge. That analysis, based largely on the increased field size resulting from the Interior Department's estimate, resulted in a reduction of the feeder-line tariff from the Arctic Refuge to TAPS from approximately \$5.50 to \$1.80. If you revise the numbers accordingly, the effective tax and royalty basis goes to \$13.20 and the State's take goes up, in turn, to approximately \$2.78 — \$0.97 per barrel less than an equivalent barrel of oil from the near-Prudhoe provinces on State lands.

If North Slope development dollars are really in short supply, then the funds to explore the Arctic Refuge and develop whatever may be discovered there are competing with funds to expand production in the provinces near Prudhoe Bay. All other things being equal, by supporting Arctic Refuge development the State is effectively penalizing itself nearly \$1.00 per barrel when compared to oil found in the Prudhoe region. Moreover, oil from the Prudhoe region bears less of an environmental regulatory burden, stands less chance of damaging a wilderness and tourism resources and is apt to be on line far sooner than oil yet to be discovered in the Arctic Refuge.

Of course, there is a very slim chance that the Arctic Refuge contains a super-giant field of light oil. Are the odds worth risking either catastrophic or chronic environmental degradation of a wilderness treasure? You and I might not answer this question the same way, but I don't think we should be considering this question without recognizing more clearly (1) the potential of the near-Prudhoe area in terms of both production prospects and profitability and (2) the economic penalties, from the state's perspective, of Arctic Refuge production.

State Shares: Near-Prudhoe Barrel v. Arctic Refuge Barrel

	<u>Near-Prudhoe Barrel</u>	<u>Arctic Refuge Barrel</u>
Market Price (at refinery)	\$20.00	\$20.00
Less:		
Arctic Refuge Pipeline Tariff (Revised estimate)	--	(1.80)
TAPS tariff	(4.00)	(4.00)
Tanker Cost	(1.00)	(1.00)
Effective Tax and Royalty Basis	\$15.00	\$13.20
State Share:		
(est. 12.5% royalty, 12.5% severance = 25%) . . .	\$3.75	
or		
(est. 6.25% roy. + 12.5% sev. = 18.75% + est. \$0.30 feeder line property tax) *		\$2.78
<u>Loss to state from industry investment in Arctic Refuge instead of near-Prudhoe development</u>	(3.75 - \$2.78 = \$0.97 per barrel)	

* Assumed 50-50 state-federal split of a 12.5% federal royalty.

Source: Revised from North Slope Profits and Production Prospects, Table 17.

I want to turn now to a different area of petroleum revenue policy: the management of settlement of long-standing pricing, pipeline tariff, tax and royalty disputes between the North Slope producers and the State is an area that has definite revenue enhancement potential. We lesser mortals in the public have no basis for judging settlements such as BP's recent income tax payment of \$630 million. In fact, the joint State-BP announcement of the settlement seems to suggest that we should stop petting toads just long enough to thank BP for granting a limited waiver of its taxpayer confidentiality so that our elected officials could inform us they had settled a dispute of this magnitude.

Despite the lamentable paucity of public information, there are some legitimate bases for being skeptical about these settlements. First, there is the lack of statutory guidelines as to what constitutes a good settlement. In most areas of public policy, administrative discretion is bounded by statute and regulation. But when oil companies consistently underpay by huge amounts their taxes and royalties, judgments about the appropriate remedy becomes a matter of administrative discretion. And in precisely this area of broad discretion, the normal checks and balances that govern administrative action are stifled by the industry's assertion of the need for confidentiality. From time to time the State has been pretty good about making settlement information available. But at other times in recent years, the state has been more willing to withhold information than either the courts or administrative law judges in pipeline proceedings have found appropriate. From a policy standpoint, what happens is this: The company acts reprehensibly, then uses the economic leverage of settlement cash to secure an agreement that denies the public any knowledge of the company's conduct. The result, from a public policy standpoint, is that settlements may encourage bad corporate behavior by hiding that conduct under the veil of confidentiality while the settlers are lauded as heroes who cut through legal red tape. The question I have is this: Was the red from the tape or from self-inflicted wounds?

Can I demonstrate the basis for my concerns more substantively? You bet. Consider the 1985 TAPS settlement.⁴ For all of the controversy and reviews of the 1985 TAPS tariff settlement, one factor that received little discussion was the clause covering dismantling, removal and restoration of the pipeline (DR&R). That clause received virtually no review because it was portrayed as revenue neutral. Here is the description of DR&R provided by the Alaska Department of Law and the U.S. Justice Department's June 1985 explanation of the settlement — an official document filed with the settlement.

Explanation of the 1985 TAPS Settlement DR&R Provision *

The schedule for the DR&R Allowance is found in Exhibit E of the Agreement. See Section II-4. As with the depreciation schedule described below, the DR&R schedule was accelerated in order to further Protestant's [State's] objective of ensuring a declining tariff profile. The annual amounts were calculated so that when they are accumulated at a rate equal to the after-tax yield on Moody's Aa bonds, the balance will be sufficient to meet the expected costs of dismantling, removal and restoration of TAPS, stipulated for purposes of the TSM [TAPS Settlement Methodology for tariff calculation] at \$872 million in 1977 dollars.

Source: State of Alaska and U.S. Department of Justice, "Explanatory Statement of the State of Alaska and the United States Department of Justice in Support of Settlement Offer," June 28, 1985, pp. 30-31. (Federal Energy Regulatory Commission Docket No. OR 78-1 [emphasis added]).

⁴ The following discussion borrows heavily from Hidden Billions, op. cit. Additionally, the writer's 1990 review of the documentary record of materials provided to the Governor, to the Legislature and to the public before and after the 1985 TAPS settlement identified and documented twenty specific examples of omission, misinformation, needlessly obscure and delayed presentations that may have hampered officials making and reviewing key policy decisions regarding this settlement (see: The 1985 TAPS Settlement: A Case Study in the Effects of Confidentiality on Information Available to Decision Makers in Oil and Gas Revenue Disputes [Supplemental Report to Oil and Gas Revenue Disputes: Status Report and Recommendations], prepared for the Alaska State Legislature, February 5, 1990).

Translation: DR&R was not supposed to be a money-making item for the TAPS owners. On the next page is the spreadsheet that described the cash flows from stipulated DR&R payment of that \$872 million in 1977 dollars. This material was presented by the Alaska Public Utilities Commission staff's expert witness more than a year after the Federal Energy Regulatory Commission approved the settlement in Washington. The annual payment figures in column L of the spreadsheet that follows are identical to the payment schedule found in the settlement's "Exhibit E." Note that when all is said and done, after dismantling the DR&R balance in column S is \$156,000.00. In short, the amount collected for DR&R was calculated to zero itself out on completion of its task.

Table I-B. TAPS SETTLEMENT METHODOLOGY FOR DETERMINING DR&R COLLECTIONS

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
Calendar Year	Nominal Fed. Tax Rate (%)	Nominal State Tax Rate (%)	Inflation Factor (Decimal)	GNP Deflator (Index)	Stipulated Expenditure Fraction (%)	Actual Expenditure (MMS)	Projected Thruput (1000 bbls)	TSM Adjustment Factors (decimal)	Adjusted Thruput (1000 bbls)	Depreciation Factor (Decimal)	DR&R Allowance (MMS)	Moody's Au Corp. Bond Yield (%)	Imputed Interest (MMS)	State Taxable Income (MMS)	State Tax (MMS)	Fed. Taxable Income (MMS)	Fed. Tax (MMS)	After-Tax Balance (MMS)
									1,795,350									
1977	48.0%	9.4%		140.1		872.1	97,094	1.00	97,094	0.015	23,536			23,536	2,212	21,323	10,235	11,088
1978	48.0%	9.4%					395,905	1.00	395,905	0.061	95,968	8.90%	0.987	0.987	0.093	96,862	46,494	61,456
1979	46.0%	9.4%					466,759	1.00	466,759	0.072	113,143	9.94%	6.109	6.109	0.574	118,677	54,591	125,542
1980	46.0%	9.4%					552,294	0.95	524,679	0.081	127,183	12.50%	15,693	15,693	1,475	141,400	65,044	201,898
1981	46.0%	9.4%					551,085	0.90	495,977	0.077	120,225	14.75%	29,780	29,780	2,799	147,206	67,715	281,389
1982	46.0%	9.4%					587,985	0.85	499,787	0.077	121,149	14.41%	40,548	161,697	15,200	146,497	67,389	360,498
1983	46.0%	9.4%					596,869	0.80	477,495	0.074	115,745	12.42%	44,774	160,519	15,089	145,430	66,898	439,030
1984	46.0%	9.4%		232.4			607,135	0.75	455,351	0.070	110,377	13.50%	59,269	169,646	15,947	153,700	70,702	522,028
1985	46.0%	9.4%	1.05	244.0			613,200	0.70	429,240	0.066	104,048	12.00%	62,643	166,691	15,669	151,022	69,470	603,580
1986	46.0%	9.4%	1.06	258.7			620,500	0.65	403,325	0.062	97,766	12.00%	72,430	170,196	15,998	154,197	70,931	686,846
1987	46.0%	9.4%	1.06	274.2			653,350	0.60	392,010	0.061	95,023	12.00%	82,422	177,445	16,680	160,765	73,952	773,659
1988	46.0%	9.4%	1.06	290.6			640,575	0.55	352,316	0.055	85,402	12.00%	92,839	178,241	16,755	161,486	74,284	860,862
1989	46.0%	9.4%	1.06	308.1			604,075	0.50	342,039	0.047	73,214	12.00%	103,303	176,517	16,593	159,925	73,565	947,221
1990	46.0%	9.4%	1.06	326.6			556,625	0.45	250,481	0.039	60,717	12.00%	113,667	174,383	16,392	157,991	72,676	1,032,537
1991	46.0%	9.4%	1.06	346.1			518,300	0.40	207,320	0.032	50,254	12.00%	123,904	174,159	16,371	157,788	72,582	1,117,742
1992	46.0%	9.4%	1.06	366.9			475,412	0.35	166,394	0.026	40,334	12.00%	134,129	174,463	16,400	158,064	72,709	1,203,096
1993	46.0%	9.4%	1.06	388.9			428,875	0.30	118,875	0.020	31,188	12.00%	144,372	175,559	16,503	159,057	73,166	1,288,987
1994	46.0%	9.4%	1.06	412.3			402,412	0.25	100,603	0.016	24,386	12.00%	154,678	179,065	16,832	162,233	74,627	1,376,593
1995	46.0%	9.4%	1.06	437.0			397,850	0.20	79,570	0.012	19,288	12.00%	165,191	184,479	17,341	167,138	76,883	1,466,847
1996	46.0%	9.4%	1.06	463.2			379,600	0.15	56,940	0.009	13,802	12.00%	176,022	189,824	17,843	171,981	79,111	1,559,717
1997	46.0%	9.4%	1.06	491.0			346,750	0.10	34,675	0.005	8,405	12.00%	187,166	195,571	18,384	177,188	81,506	1,655,398
1998	46.0%	9.4%	1.06	520.5			321,300	0.05	15,060	0.002	3,893	12.00%	198,648	202,541	19,039	183,502	84,411	1,754,489
1999	46.0%	9.4%	1.06	551.7			299,300	0.05	14,965	0.002	3,628	12.00%	210,539	214,166	20,132	194,035	89,256	1,859,268
2000	46.0%	9.4%	1.06	584.8			301,125	0.05	15,056	0.002	3,650	12.00%	223,112	226,762	21,316	205,446	94,505	1,970,209
2001	46.0%	9.4%	1.06	619.9			284,700	0.05	14,235	0.002	3,451	12.00%	236,425	239,876	22,548	217,327	99,971	2,087,565
2002	46.0%	9.4%	1.06	657.1			266,450	0.05	13,322	0.002	3,229	12.00%	250,508	253,737	23,851	229,886	105,748	2,211,704
2003	46.0%	9.4%	1.06	696.5			235,425	0.05	11,771	0.002	2,853	12.00%	265,404	268,258	25,216	243,042	111,799	2,342,946
2004	46.0%	9.4%	1.06	738.3			215,350	0.05	10,767	0.002	2,610	12.00%	281,154	283,764	26,674	257,090	118,261	2,481,775
2005	46.0%	9.4%	1.06	782.6			198,925	0.05	9,946	0.002	2,411	12.00%	297,813	300,224	28,221	272,003	125,121	2,628,656
2006	46.0%	9.4%	1.06	829.6			184,325	0.05	9,216	0.001	2,234	12.00%	315,439	317,673	29,861	287,812	132,393	2,784,075
2007	46.0%	9.4%	1.06	879.3			158,775	0.05	7,939	0.001	1,924	12.00%	334,089	336,013	31,585	304,428	140,037	2,948,466
2008	46.0%	9.4%	1.06	932.1			136,875	0.05	6,844	0.001	1,659	12.00%	353,816	355,475	33,415	322,060	148,148	3,122,378
2009	46.0%	9.4%	1.06	988.0			105,850	0.05	5,292	0.001	1,283	12.00%	374,685	375,968	35,341	340,627	156,689	3,306,317
2010	46.0%	9.4%	1.06	1047.3	2.5%	162,982	78,475	0.05	3,924	0.001	0,951	12.00%	396,758	397,709	37,385	197,342	90,777	3,412,882
2011	46.0%	9.4%	1.06	1110.1	5.0%	345,522	65,700	0.05	3,285	0.001	0,796	12.00%	409,546	410,342	38,572	26,248	12,074	3,427,055
2012	46.0%	9.4%	1.06	1176.7	50.0%	3,662,536						12.00%	411,247	411,747	0.000	(3,251,290)	(1,495,593)	1,671,359
2013	46.0%	9.4%	1.06	1247.4	30.0%	2,329,373						12.00%	200,563	200,563	0.000	(2,128,810)	(979,253)	521,802
2014	46.0%	9.4%	1.06	1322.2	10.0%	823,045						12.00%	62,616	62,616	0.000	(700,429)	(349,797)	111,170
2015	46.0%	9.4%	1.06	1401.5	2.5%	218,107						12.00%	13,340	13,340	0.000	(204,767)	(94,193)	0.598
							13,345,125		6,459,246									0.160

Surplus DR&R in 1997 MM \$ 0.160

Source: Cash flows from the DR&R element of TAPS Settlement Methodology (TSM) prepared by Rudolph L. Bertchi (Alaska Public Utilities Commission staff expert witness in the TAPS case) for State of Alaska Office of Management and Budget, June 1, 1988; based on Trans-Alaska Pipeline System Interstate Settlement Agreement, June 28, 1985, Sec. II-4, Exhibit II; see also Explanatory Statement of State of Alaska and U.S. Dept. of Justice, June 29, 1985, pp. 30-31. (Surplus DR&R in 1997 \$ calculated from spreadsheet.)

\$157,000

That's what we were told the settlement did. What the collected DR&R money actually did is very different. What follows is an update of the same spreadsheet calculating the value of TAPS DR&R payments to the owner companies. Note that the TAPS owners' estimated after-tax balance in 1992 is almost \$3.5 billion, nearly triple the \$1.2 billion estimated back in 1977. This is the same spreadsheet with identical cash inputs at column (L). I have boxed the only changes to the 1985 spreadsheet you just saw at columns (B), (C), (D) and (M). Columns (B) and (C) reduce the owners' pay-outs to represent estimated actual tax rates rather than nominal tax rates and Column (M) substitutes the owner companies' return on equity from 1982 through 1991, as reported in the Fortune 500, for the Moody's bond rate stipulated in the settlement. As a result of these changes, in the year 2015, the TAPS owners will have a tax-paid surplus after dismantling of \$22.2 billion in 1992 dollars. I also estimated the tax-paid DR&R balance at the frequently used industry standard 10% real rate of return, or 10% over inflation. The result was that the TAPS DR&R collections produced a tax-paid surplus of \$11.7 billion.

Twelve to \$22 billion on an item officially portrayed as "sufficient to meet the expected costs"? Go figure. Note: This \$12 to \$22 billion in after-tax profit is over and above the \$4.77 per-barrel profit that produced the North Slope returns discussed above. In the per-barrel calculations presented above, DR&R is treated as a shipping cost at line 5(g). The discoverer of this hole in the TAPS settlement — the APUC's staff expert witness — characterized the owners' DR&R windfall as an off-book or hidden profit.

Table 2-B. ESTIMATED VALUE TO TAPS OWNERS OF TSM DR&R COLLECTIONS AT OWNER COMPANIES' 1982-1991 RATE OF RETURN

Col. (A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	
Calendar Year	Fed. Tax Rate (%)	State Tax Rate (%)	Inflation Factor (Decimal)	GNP Deflator (Index)	Stipulated Expenditure Fraction (%)	Actual Expenditure (MM\$)	Projected Thruput (1000 bbls)	TSM Adjustment Factors (decimal)	Adjusted Thruput (1000 bbls)	Depreciation Factor (Decimal)	DR&R Allowance (MM\$)	Parent Co. Ret. on Equity (%)	Imputed Interest (MM\$)	State Taxable Income (MM\$)	State Tax (MM\$)	Fed. Taxable Income (MM\$)	Fed. Tax (MM\$)	After-Tax Balance (MM\$)	
/----- Revised Estimates -----/																			
											1,795,350								
1977	25.0%	4.0%		140.1		872.1	97,094	1.00	97,094	0.015	23,536	13.04%		23,536	2,212	21,323	5,331	15,992	
1978	25.0%	4.0%				395,905	395,905	1.00	395,905	0.061	95,968	17.14%	2,741	2,741	0.110	98,599	24,650	89,942	
1979	25.0%	4.0%				466,759	466,759	1.00	466,759	0.072	113,143	32.13%	28,898	28,898	1.156	140,885	35,221	195,605	
1980	25.0%	4.0%				552,294	552,294	0.95	524,679	0.081	127,183	35.86%	70,144	70,144	2.806	194,521	48,630	341,496	
1981	25.0%	4.0%				551,085	551,085	0.90	495,977	0.077	120,225	24.50%	83,667	83,667	3.347	200,545	50,136	491,905	
1982	25.0%	4.0%				587,985	587,985	0.85	499,787	0.077	121,149	18.40%	90,510	211,659	8,466	203,193	50,798	644,299	
1983	25.0%	4.0%				596,869	596,869	0.80	477,495	0.074	115,745	18.40%	118,551	234,296	9,372	224,924	56,231	812,993	
1984	25.0%	4.0%		232.4		607,135	607,135	0.75	455,351	0.070	110,377	18.40%	149,591	259,968	10,399	249,569	62,392	1,000,170	
1985	25.0%	4.0%	1.036	240.8		613,200	613,200	0.70	429,240	0.066	104,048	18.40%	184,031	288,079	11,523	276,556	69,139	1,207,587	
1986	25.0%	4.0%	1.019	245.3		620,500	620,500	0.65	408,325	0.062	97,766	18.40%	222,196	319,962	12,798	307,164	76,791	1,437,960	
1987	25.0%	4.0%	1.036	254.2		653,350	653,350	0.60	392,010	0.061	95,023	18.40%	264,585	359,608	14,384	345,224	86,306	1,696,877	
1988	25.0%	4.0%	1.041	264.6		640,575	640,575	0.55	352,316	0.055	85,402	18.40%	312,225	397,627	15,905	381,722	95,430	1,983,169	
1989	25.0%	4.0%	1.048	277.3		604,075	604,075	0.50	302,038	0.047	73,214	18.40%	364,903	439,117	17,525	420,592	105,148	2,298,613	
1990	25.0%	4.0%	1.054	292.3		526,625	526,625	0.45	250,481	0.039	60,717	18.40%	422,945	483,662	19,346	464,315	116,079	2,646,849	
1991	25.0%	4.0%	1.042	304.5		518,300	518,300	0.40	207,320	0.032	50,254	18.40%	487,020	537,275	21,491	515,784	128,946	3,033,687	
1992	25.0%	4.0%	1.038	314.6		475,412	475,412	0.38	166,594	0.026	40,336	18.40%	558,198	598,339	23,941	576,391	145,648	3,464,631	
1993	25.0%	4.0%	1.036	325.9		428,875	428,875	0.30	128,663	0.020	31,188	18.40%	637,492	668,680	26,747	641,933	160,483	3,946,080	
1994	25.0%	4.0%	1.037	338.1		402,412	402,412	0.25	100,603	0.016	24,386	18.40%	726,079	750,465	30,019	720,446	180,112	4,486,415	
1995	25.0%	4.0%	1.039	351.1		397,350	397,350	0.20	79,570	0.012	19,288	18.40%	825,500	844,788	33,792	810,997	202,749	5,094,662	
1996	25.0%	4.0%	1.041	365.6		379,600	379,600	0.15	56,940	0.009	13,802	18.40%	937,418	951,220	38,049	913,171	228,293	5,779,541	
1997	25.0%	4.0%	1.043	381.3		346,750	346,750	0.10	34,675	0.005	8,405	18.40%	1,063,436	1,071,841	42,874	1,028,967	257,242	6,551,266	
1998	25.0%	4.0%	1.043	397.5		321,200	321,200	0.05	16,060	0.002	3,893	18.40%	1,205,433	1,209,326	48,373	1,160,953	290,238	7,421,981	
1999	25.0%	4.0%	1.043	414.6		299,300	299,300	0.05	14,965	0.002	3,628	18.40%	1,365,645	1,369,272	54,771	1,314,501	328,625	8,407,857	
2000	25.0%	4.0%	1.044	432.7		301,125	301,125	0.05	15,056	0.002	3,650	18.40%	1,547,046	1,550,695	62,028	1,488,668	372,167	9,524,358	
2001	25.0%	4.0%	1.044	451.7		284,700	284,700	0.05	14,235	0.002	3,451	18.40%	1,732,482	1,755,932	70,237	1,685,695	421,424	10,788,629	
2002	25.0%	4.0%	1.044	471.5		266,450	266,450	0.05	13,322	0.002	3,229	18.40%	1,985,108	1,988,337	79,533	1,908,804	477,201	12,220,232	
2003	25.0%	4.0%	1.044	492.2		235,425	235,425	0.05	11,771	0.002	2,853	18.40%	2,248,523	2,251,376	90,055	2,161,321	540,330	13,841,222	
2004	25.0%	4.0%	1.044	513.8		215,350	215,350	0.05	10,767	0.002	2,610	18.40%	2,546,785	2,549,395	101,976	2,447,419	611,855	15,676,787	
2005	25.0%	4.0%	1.044	536.4		198,925	198,925	0.05	9,946	0.002	2,411	18.40%	2,884,529	2,886,940	115,478	2,771,462	692,866	17,755,383	
2006	25.0%	4.0%	1.044	560.0		184,325	184,325	0.05	9,216	0.001	2,234	18.40%	3,266,991	3,269,225	130,769	3,138,456	784,614	20,109,225	
2007	25.0%	4.0%	1.044	584.5		158,775	158,775	0.05	7,939	0.001	1,924	18.40%	3,700,097	3,702,022	148,081	3,553,941	888,485	22,174,681	
2008	25.0%	4.0%	1.044	610.2		136,875	136,875	0.05	6,844	0.001	1,659	18.40%	4,190,541	4,192,200	167,688	4,024,512	1,006,128	25,793,065	
2009	25.0%	4.0%	1.044	637.0		105,850	105,850	0.05	5,292	0.001	1,283	18.40%	4,745,924	4,747,207	189,888	4,557,319	1,139,330	29,211,054	
2010	25.0%	4.0%	1.044	664.9	2.5%	103,479	78,475	0.05	3,924	0.001	0,951	18.40%	5,374,834	5,375,785	215,031	5,057,274	1,264,319	33,004,009	
2011	25.0%	4.0%	1.044	694.1	5.0%	216,044	65,700	0.05	3,285	0.001	0,796	18.40%	6,072,738	6,073,534	242,941	5,614,548	1,403,637	37,214,921	
2012	25.0%	4.0%	1.044	724.6	50.0%	2,255,286		0.05				18.40%	6,847,545	6,847,545	0.000	4,592,259	1,148,065	40,659,115	
2013	25.0%	4.0%	1.044	756.4	30.0%	1,412,576		0.05				18.40%	7,481,277	7,481,277	0.000	6,068,701	1,517,175	45,210,640	
2014	25.0%	4.0%	1.044	789.6	10.0%	491,529		0.05				18.40%	8,318,758	8,318,758	0.000	7,827,228	1,956,807	51,081,062	
2015	25.0%	4.0%	1.044	824.3	2.5%	128,277		0.05				18.40%	9,398,915	9,398,915	0.000	9,270,638	2,317,660	54,001,041	
							13,345,125		6,459,246										

Surplus DR&R in 1992 MM\$ = 22,150,017

Source: TAPS Settlement Methodology DR&R calculations (Table 1), modified as follows:

Col. (B), (C): Estimated actual taxes, based on aggregate information from Alaska Dept. of Revenue.

Col. (D): 1977-1991 = U.S. CPI-U; subsequent years = Alaska Dept. of Revenue Spring 1992 revenue forecast.

Col. (M): 1977-81: Standard & Poor's, Vol. 53 (from Bertsch APUC Testimony, Dec. 17, 1986, Exh. RLB-15, p. 2); 1982-91 = ARCO & Exxon Avg. Total Return to Investors (Fortune, April 20, 1992); subsequent years = 1982-91 avg.

\$22,150,017

If you ask the owner companies about TAPS DR&R, you will probably be told one of two things:

(1) There is no such DR&R fund, so it's meaningless to calculate its value, but we'll be there to fulfill our legal obligations when the time comes. Translation: the company has paid these funds out to its shareholders. Or:

(2) A deal is a deal, and besides it might cost more than we anticipated. Who knows what inflation will bring and what those crazy greenies will dream up next? Calculate the return under double-digit inflation and a doubling of estimated pay-outs, and even under this double-whammy the DR&R collections still generate a tax-paid surplus. A better way to handle this kind of long-term uncertainty might be to escrow the collections with a periodic review of the collection terms to ensure their adequacy.

In short, the industry ran off with a bundle equal to five to ten years of general fund budgets on an item of a settlement that was billed as revenue neutral. How did it happen? Elsewhere, I have noted that the record of the TAPS settlement is laced with misinformation to decision-makers, and that most of the intensive review the TAPS settlement received was after the State's settling team had already committed the State to the terms of the settlement. As a result, the review was a debate between knowledgeable specialists with a vested interest in their settlement and uninformed generalists. Those specialists now say, "A settlement is a set of compromises." You see that language in every settlement announcement. Or they say, "We knew all along what we were giving away." I am aware of no discussion by settlement reviewers of what we might have received in exchange for the DR&R provision that gave the TAPS owners an off-book profit of \$12 to \$22 billion over and above the forgiveness of billions of dollars in refunds. The main focus of TAPS settlement review was on the manner in which the settlement allowed the owner companies to trot off with billions of dollars of past over-charges in exchange for lower future tariffs. But lower future tariffs was something we were likely to achieve in court

without giving up refunds. The DR&R give-away was not discussed, to my knowledge, until it was reported by the staff of the Alaska Public Utilities Commission a year after the settlement was completed.

Are the post-TAPS settlements as bad? Perhaps not. But the smokescreen of confidentiality may hide problems that cost the citizens of Alaska millions of dollars annually. Based on my experience with the Administration's oil and gas litigation efforts between 1987 and mid-1989, I believe the post-TAPS settlements are prone to contain hidden defects that result principally from two factors: (1) the desire of the negotiators to come away from the table with a settlement and (2) the perversion of public policy due to the erosion of checks and balances resulting from industry's successful assertion of a right to what I believe to be excessive confidentiality. Where the would-be critic can push the record to demonstrate concerns based on public information, the State's settling team can come back with a self-righteously indignant claim that the critic simply does not have the big picture. In cases where I am aware of settlement defects and have enough knowledge of the settlement parameters to determine with confidence that the problems are significant, I am restrained from sharing my concerns by confidentiality statutes and agreements. Not a healthy climate for public policy involving billions of dollars.

I will conclude by suggesting four remedies that could be implemented fairly quickly and easily. The thrust of these measures would be to improve inter-agency coordination and maximize public information on oil and gas issues that are so vital to the State's future.

==> (1) Require by law an annual State audit and report to the Legislature by the Legislative Audit staff on all tax, royalty and pipeline disputes over a certain dollar amount and/or age. The annual report should contain an update on ongoing cases with a status report on significant issues and should be issued in two forms: a confidential report to the Legislative Budget and Audit Committee and a public report containing as much information as the auditors can shoe-horn into the

record under existing statutes. In this manner, the Legislature would gain the information it needs to have effective legislative oversight to insure that State policies in this important area are integrated and effective.

==> (2) Proscribe by law any tax or royalty or pipeline settlement that extends confidentiality beyond provisions required by law.

Statutes to effect these two changes were proposed by the Department of Revenue in 1990 and passed the House unanimously, only to die in a watered-down version of the bill that passed the Senate in the final moments of the session but did not get back to the House in time to become law.

==> (3) Transfer pipeline authority from the Department of Law by amending AS 42.06 — the statute governing the Alaska Public Utilities Commission that gives management of inter-state pipeline management to the Department of Law — to give authority for pipeline policy to an agency with a resource or revenue management mandate. The Department of Law will still handle inter-state tariffs through its control over all state contract attorneys who work for the State, but those attorneys would also be working for and tasked by a client agency with resource or revenue responsibilities instead for the Department of Law, which has no such management authority in statute.

==> (4) Re-establish within the administration an inter-agency group to coordinate oil and gas policy. That group should as its first order of business establish a formal mechanism to guarantee a coordinated policy on oil and gas litigation that ensures that the implications of all major settlements are reviewed independently prior to settlement to avoid perverse policy impacts that the settling team may fail to recognize. The second order of business should be to consider whether the information the industry deems confidential really serves any purpose other than to hamstring policy makers and blind the public. From sad experience, I can guarantee that this suggestion will meet with resistance from resource managers who will feel that their administrative latitude is being constrained.

From an information standpoint, with such measures in place, we could rely on our public agencies to produce reports making clear the kind of profits the North Slope is generating and will continue to generate for some years to come, as well as the better information in the arcane area of settlements. From a policy standpoint, with these measures in place, reports such as the DR&R analysis summarized here will, hopefully, be unnecessary in the future.

I can give you a bottom line on these proposals because I learned how to translate policy options into dollars and cents by reading countless analyses by the State's litigation lawyers. Whether such results are meaningful I leave for you to determine. Here's my assessment: First, there are tangible gains. Assume we have outstanding tax and royalty claims of \$4 billion, and that we tend to settle for something like \$0.50 on every dollar we claim. That's \$2 billion. Then assume the recommended oversight measures increase settlement gains by ten percent. That's \$200 million. There's a kicker: Assume the better precedent of the tougher settlements yields a similar gain in the future through deterrence of future delays and encouragement of higher future payments. Total gain: \$400 million. That money could probably fund a good chunk of your favorite general fund program that is now in jeopardy. Additionally, there's the more difficult to quantify value of preventing or reducing the risk of a give-away like the DR&R clause in the 1985 TAPS settlement. Not bad pay-off on a few simple and relatively inexpensive housekeeping measures.

I wish you luck in your endeavors and look forward to your questions. Thank you.

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North Slope Profits and Production Prospects

A report by

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November 12, 1992

**Prepared for:
Senate Finance Committee
Alaska State Legislature**

**Project Director:
Senator Jalmar Kerttula, Co-Chair
Senate Finance Committee**

Foreward

This report would not have been possible without information provided by personnel with the Department of Revenue's Oil and Gas Audit Division research unit. Others state personnel graciously provided information, including contract specialists with the Department of Law who monitor pipeline tariffs, staff of the Department of Natural Resources Division of Oil and Gas, the State Pipeline Coordinator's Office and the Alaska Oil and Gas Conservation Commission. Of the many additional people who provided information, the insights of Professor G.D. Sharma at the University of Alaska's Petroleum Development Laboratory and Professor Elmer Dougherty of the University of Southern California were particularly useful. My gratitude to these and other unnamed sources does not alter the fact that responsibility for the approach, data and conclusions presented in this report rests entirely with the author.

In the belief that the public needs access to better information in this important public policy arena, I have footnoted extensively. Understanding production prospects on the North Slope, the unique profitability of that area and the relationship between the two is necessarily complicated; suggestions to improve the materials presented here will be welcome.

Finally, this report would not have been possible without Senator Jalmar Kerttula's continued interest in identifying and exploring the factors that will determine the future of North Slope oil development.

Richard A. Fineberg
Talkeetna, Alaska
November 12, 1992

North Slope Profits and Production Prospects

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Executive Summary

==> Continual increases in forecasted production from the North Slope stand in marked contrast to the industry's fatuous claims that the golden goose of the North Slope is about to cackle its last. In April 1992 the annual forecast of the Department of Natural Resources estimated North Slope production from 1992 through 2010 at 6.86 billion barrels. This figure represents an increase of 5.5% over the department's 1991 forecast and 68.7% over that of 1985. (*Section II.A.*)

==> Forecasted production for the 1992-2010 period has increased 39.2% over the 1989 forecast. The vast majority of the increase since 1989 has come at Prudhoe Bay and Kuparuk, contradicting repeated industry warnings that correction of the severance tax economic limit factor (ELF) "will only make the next barrel of oil more expensive to produce and therefore it will be less likely to ever be produced. . . . that means there will be more oil left in the ground" because "new work [at Prudhoe and Kuparuk] . . . to add a hundred million barrels here, a hundred million barrels there . . . can become too expensive." The tax loophole was closed despite industry warnings. (*Section II.C.*)

==> In real terms, the annual average price of North Slope crude oil has been relatively flat since 1986. (*Section III.C., Graph 1*)

==> In the absence of comprehensive information on North Slope profitability, a per-barrel profitability model was developed. (*Section III.C.*)

==> The model delineates the importance of pipeline costs and profits to the economic viability of North Slope operations. Since the North Slope producing companies undoubtedly consider pipeline profits in their development decisions, forecasts that omit this crucial element should be regarded as irrelevant. (*Section III.C.; III.E., p. 86.*)

==> Although their significance is masked in all-field average calculations, feeder pipeline costs and profits can play a significant role in determining the profitability of an individual field. (*Section III.D.; p. 69, Graph 3.*)

==> The model indicates that North Slope production, feeder line and Trans-Alaska Pipeline System (TAPS) profits for calendar year 1991 averaged approximately \$4.77 per barrel. With total production of 6.86 billion barrels, the North Slope operators

earned in excess of \$3.0 billion in calendar year 1991. This figure places the North Slope operators on a par with the second most profitable corporation on the 1991 Fortune 500. This figure does not include downstream profits, the intangible value to refiners of a stable crude supply or the off-book profits from TAPS DR&R collections. (Section III.D.; Table 12-A, Graph 2.)

⇒ The model shows the least profitable field on the North Slope — Milne Point — to be marginally profitable at current prices, even without the benefit of TAPS profits. (Section III.D., Tables 12-F, 13-F and 14-F.)

⇒ Estimated North Slope production and pipeline profits for FY 2000 of \$1.9 billion would place the North Slope operators on a par with the seventh most profitable corporation on the 1991 Fortune 500. Because the Department of Revenue removed West Sak from its Spring 1992 forecast, this figure does not include West Sak production. (Section III.E.; Table 15-A, Graph 4.)

⇒ Additional production of 150,000 barrels per day from West Sak would add approximately \$200 million to total North Slope profitability in FY 2000. (Section III.E.; Table 16, p. 85.)

⇒ Due to its distance from TAPS and the fact that it is on federal land, a barrel of oil discovered in the Arctic National Wildlife Refuge would generate approximately \$1.67 less for the state in taxes and royalty payments than a barrel of equivalent oil discovered on state land in the Prudhoe Bay region. From a direct revenue standpoint, in promoting the Arctic Refuge over near-Prudhoe development the state is effectively penalizing itself by this amount. (Section IV.A.; Table 17.)

⇒ If Eladami and Kuvlum prove to be major discoveries, they could increase the economic attractiveness of any discovery in the Arctic Refuge by reducing the economic penalties of a stand-alone feeder line from the arctic Refuge. At this time neither discovery has been delineated and Kuvlum's location — 15 miles off shore — presents a significant obstacle to production. (Section IV. B.)

⇒ While it is reasonable to defer economic decisions involving a major North Slope natural gas sale until there is a concrete proposal, issues discussed in this report pertaining to forecasts, pipeline matters and basic information from the industry indicate that problems in inter-agency coordination may prevent state officials from defining issues and making recommendations in a timely manner. (Section IV.C.)

I. Introduction

This report has three basic goals:

1. to bring up to date a report the author prepared for the Alaska State Legislature in December 1990 on potential North Slope oil and gas developments (Chapter II.);
2. to estimate current per-barrel returns to the industry, state and federal governments at recent oil prices (Chapter III.); and
3. to consider North Slope development policy questions in light of recent events and the unique economics of the North Slope (Chapter IV.).

The game plan is straight-forward:

In the second chapter, recent increases in state production forecasts are charted. A central point of the 1990 report was that although North Slope production was declining, improved production techniques had consistently delayed and softened the forecasted decline. This trend resulted in forecasts between 1985 and 1990 that showed continually increasing total production from North Slope fields between 1990 and 2010. Two years later, that trend is still evident. Despite the increases in forecasted production and the fact that more than a decade remains before shutdown becomes a pressing question, the public has been treated to a steady bombardment of warnings from the industry that with shutdown approaching, costly environmental regulations will cause a premature demise of Alaska's golden goose. Conflicts between estimates of different state agencies and estimates of other informed observers add a layer of confusion to the industry's propaganda campaign. The West Sak field and information provided by the industry on production prospects during the 1989 debate over revision of a tax factor known as the economic limit factor (ELF) are also discussed.

Because the reason for production is profit, North Slope production prospects cannot be understood without a firm grasp on the profits North Slope producers derive from their Alaska operations. Unfortunately, there is a paucity of information on North Slope profitability. Chapter III. seeks to remedy that problem by assembling public information from a variety of sources to set up a model of North Slope profits at current prices and under future scenarios. Per-barrel profit analysis provides another tool for assessing the significance of the industry's incessant warnings that the Golden Goose is about to cackle its last.

With production and profit data assembled, the fourth chapter offers brief consideration of several recent developments and their potential effects on the future of North Slope operations. Items selected for focus are the Arctic National Wildlife Refuge, the recent discoveries east of Prudhoe Bay and a major natural gas sale.

II. Production Forecasts

A. Recent Trends in North Slope Production Forecasts

In November 1991, a clear message was passed at the American Petroleum Institute's annual meeting in Houston: "The American industry is not abandoning the United States; we're being thrown out, closed out," Mobil Corp. Chairman Allen M. Murray told the leading oil industry trade group.¹ Picking up on this theme, six weeks later Alyeska Pipeline Service Co. President James Hermiller told the Anchorage Chamber of Commerce that Alyeska was about to begin its eventual shut down. Lay-offs were coming, he warned. In the near future, Alyeska might even close a pump station or two. Hermiller then gave his usual strong plug for a cost-benefit approach to environmental regulation: "If the state imposes excessive financial burdens on the owners of the production going through the line or on the pipeline system itself, the line will close sooner than later."² Hermiller's adaptation of the API pitch was misleading; he overstated the decline and incorrectly linked it with environmental regulations. But Hermiller's pitch at least had an aura of theoretical plausibility; his minions at Alyeska applied the API Houston theme in a manner that defied both facts and logic.³

It is true that the Alaska Department of Natural Resources (DNR) April 1992 annual production forecast shows North Slope production dropping from the current level — about 1.7 million barrels per day — to just below one million barrels per day in the year 2001. But the North Slope's well-publicized declining daily production rate is only one part of the North Slope oil development picture. Hermiller did not mention that the same forecast six years earlier had predicted that North Slope production would slip under the million-barrel milestone in 1995. But now the current DNR forecast predicts that in 1995 the North Slope will still be producing in excess of 1.6 million barrels per day, very near the current level.

Tables 1 through 6 present DNR's field-by-field breakdown of annual forecasts of production from 1992 through 2010. As in the previous report, the Department of Natural

¹ Laura Tolley, "Big Oil 'must go' outside: Environment forcing firms out, exec says," Anchorage Daily News, Nov. 19, 1991, p. B-4.

² Hermiller's Jan. 6 speech was headlined on the front page of the Anchorage Times Jan. 7, repeated in an editorial the following day and reprinted in full in the Anchorage Times, Jan. 12, 1992.

³ For example, see footnote 53, below.

Tables 1 through 6 present DNR's field-by-field breakdown of annual forecasts of production from 1992 through 2010. As in the previous report, the Department of Natural Resources forecast is used because that agency's annual forecast is a consistent and more or less direct reflection of information the industry provides the state of its current plans. The year 1985 was selected as the reference point because that was the final forecast before the oil price crash that ushered in a new era of lower oil prices.

Table 1.

1985 Production Forecast (Alaska Dept. of Natural Resources)

000 Barrels per day:

<i>Year</i>	<i>Field =></i>	Prudhoe	Kuparuk	Lisburne	Pt. McIntyre	Endicott	Milne	Other	W.Sak	Beaufort	Total
1992		850	200	90		100	15	50	<=====		1,305 (KK) bpd
1993		750	200	75		85	10	50	<=====		1,170 "
1994		650	170	70		75	10	50	<=====		1,025 "
1995		575	145	65		70	10	100	<=====		965 "
1996		510	120	60		65	0	125	<=====		880 "
1997		460	100	55		60		125	<=====		800 "
1998		420	80	50		55		125	<=====		730 "
1999		380	75	40		50		125	<=====		670 "
2000		340	65	30		45		120	<=====		600 "
2001		300	55	20		40		115	<=====		530 "
2002		270	50	10		20		110	<=====		460 "
2003		240	40	0		10		105	<=====		395 "
2004		210	35			0		100	<=====		345 "
2005		180	30					95	<=====		305 "
2006		160	25					90	<=====		275 "
2007		140	20					80	<=====		240 "
2008		110	15					70	<=====		195 "
2009		80	10					60	<=====		150 "
2010		50	0					50	<=====		100 "
Total Barrels:		<u>2,436,375</u>	<u>523,775</u>	<u>206,225</u>	<u>0</u>	<u>246,375</u>	<u>16,425</u>	<u>636,925</u>	<=====		<u>4,066,100 (KK) bbls.</u>

Source: Dept. of Natural Resources, "Historical and Projected Oil & Gas Consumption," January 1985, p. 13 (Table 2.2: Estimated Availability of N. Slope Oil For Sale).

5-2

Table 2.

1988 Production Forecast (Alaska Dept. of Natural Resources)

000 Barrels per day:

<i>Year</i>	<i>Field =></i>	Prudhoe	Kuparuk	Liaburne	Pt. McIntyre	Endicott	Milne	Other	W.Sak	Beaufort	Total	
1992		1,062	240	70		85	10	0			1,467	(XX) bpd
1993		924	205	70		75	0	0			1,274	"
1994		804	175	70		70		0			1,119	"
1995		699	150	70		65		135	<=====		1,119	"
1996		608	125	70		60		135	<=====		998	"
1997		529	105	70		55		135	<=====		894	"
1998		461	90	65		50		120	<=====		786	"
1999		400	75	58		45		108	<=====		686	"
2000		348	65	52		40		103	<=====		608	"
2001		303	55	47		20		98	<=====		523	"
2002		264	45	42		10		112	<=====		473	"
2003		230	40	38		0		105	<=====		413	"
2004		200	35	34				100	<=====		369	"
2005		174	30	31				95	<=====		330	"
2006		151	25	28				88	<=====		292	"
2007		131	25	25				67	<=====		248	"
2008		114	20	20				56	<=====		210	"
2009		100	15	15				44	<=====		174	"
2010		86	10	10				42	<=====		148	"
Total Barrels:		2,769,620	558,450	323,025	0	209,875	3,650	563,195	<=====		4,427,815	(XX) bbls

Source: Dept. of Natural Resources, "Historical and Projected Oil & Gas Consumption," January 1988, p. 9 (Table 2.2A: Production Forecast and Available Royalty Oil).

Table 3.

1989 Production Forecast (Alaska Dept. of Natural Resources)

(XX) Barrels per day:

Year	Field =>	Prudhoe	Kuparuk	Liaburne	Pt. McIntyre*	Endicott	Mine	Other *	W.Sak	Beaufort	Total
1992		1,251	240	40		85	10	0	6	<===	1,632 (XX) bpd
1993		1,126	205	40		75	7	20	6	<===	1,479 "
1994		1,011	175	40		70	7	60	6	<===	1,369 "
1995		862	150	37		65	6	58	12	<===	1,190 "
1996		731	125	34		60	5	56	12	<===	1,023 "
1997		620	105	31		55	4	55	25	<===	895 "
1998		528	90	28		50	0	89	25	<===	810 "
1999		450	75	25		45		83	50	<===	728 "
2000		383	65	21		40		78	50	<===	637 "
2001		327	55	19		20		73	75	<===	569 "
2002		264	45	13		10		64	75	<===	471 "
2003		230	40	9		0		56	100	<===	435 "
2004		200	35	5				49	100	<===	389 "
2005		174	30	0				38	150	<===	392 "
2006		151	25					32	150	<===	358 "
2007		131	20					27	150	<===	328 "
2008		114	15					23	150	<===	302 "
2009		100	15					13	140	<===	268 "
2010		86	10					11	120	<===	227 "
Total Barrels:		3,189,735	554,800	124,830	0	209,875	14,235	323,025	511,730	<===	4,928,230 (XX) bbls.)

* "Other" includes some Pt. McIntyre production.

Source: Dept. of Natural Resources, "Historical and Projected Oil & Gas Consumption," January 1989, p. 8 (Table 2.2: Production Forecast and Available Royalty Oil)

Table 4.

1990 Production Forecast (Alaska Dept. of Natural Resources)

<i>000 Barrels per day:</i>												
Year	Field =>	Prudhoe	Kuparuk	Lisburne	Pt. McIntyre	Endicott	Milne	Niakuk	W.Sak	Beaufort	Total	
1992		1,102	280	40	20	85	20	0	6		1,553	(TKK) bpxl
1993		1,014	250	40	60	75	16	20	6		1,481	"
1994		932	220	40	60	70	13	20	12		1,367	"
1995		857	190	37	60	65	10	20	12		1,251	"
1996		789	175	34	54	60	8	17	12		1,149	"
1997		726	150	31	49	55	7	14	25		1,057	"
1998		668	125	28	44	50	6	12	25		958	"
1999		614	105	25	39	45	5	10	50	0	893	"
2000		553	90	21	35	40	5	9	50	60	863	"
2001		498	75	19	32	20	5	7	75	54	785	"
2002		448	65	13	29	10	0	6	75	49	695	"
2003		403	55	9	26	0		5	100	44	642	"
2004		363	45	5	23			5	100	39	580	"
2005		326	35	0	21			0	150	35	567	"
2006		284	30		19				150	32	515	"
2007		247	25		17				150	29	468	"
2008		215	20		15				150	26	426	"
2009		187	15		14				140	23	379	"
2010		163	10		12				126	21	326	"
Total Barrels:		3,791,985	715,400	124,830	229,585	209,875	34,675	52,925	513,920	150,380	5,823,575	(TKK) bbls.)

Source: Dept. of Natural Resources, "Historical and Projected Oil & Gas Consumption," January 1990, p. 10 (Table 2.2: Production Forecast and Available Royalty Oil).

Table 5.

1991 Production Forecast (Alaska Dept. of Natural Resources)

000 Barrels per day:

Year	Field =>	Prudhoe	Kuparuk	Lisburne	Pt. McIntyre	Endicott	Milne	Niakuk	W. Sak	Beaufort	Total	
1992		1,248	300	44	0	108	19	0	0		1,719	(MM) bpd
1993		1,096	300	40	75	94	17	0	6		1,628	"
1994		987	300	34	80	83	16	0	6		1,506	"
1995		988	280	27	80	72	16	0	6		1,469	"
1996		889	250	22	80	63	17	10	12		1,343	"
1997		799	220	17	72	55	18	20	12		1,213	"
1998		739	190	14	65	47	19	20	12		1,106	"
1999		683	170	11	58	40	20	17	25	0	1,024	"
2000		632	150	10	52	34	20	14	25	60	997	"
2001		584	125	9	47	29	18	12	50	54	928	"
2002		526	105	7	41	24	16	10	50	49	828	"
2003		474	90	5	36	21	14	9	75	44	768	"
2004		426	75	0	30	18	13	7	75	39	683	"
2005		383	65	0	26	16	12	6	75	35	618	"
2006		345	55		22	0	10	5	67	32	536	"
2007		293	45		19		8	5	61	29	460	"
2008		249	35		16		6		55	26	387	"
2009		212	30		14		5		50	23	334	"
2010		180	25		12				42	21	280	"
Total Barrels:		4,282,545	1,025,650	87,600	301,125	256,960	96,360	49,275	256,960	150,380	6,506,855	(MM) bbls.

Source: Dept. of Natural Resources, "Historical and Projected Oil & Gas Consumption," June 1991, pp. 4-5 (Table 2.1: Production Forecast and Available Royalty Oil)

Table 6.

1992 Production Forecast (Alaska Dept. of Natural Resources)

000 Barrels per day:

Year	Field =>	Prudhoe	Kuparuk	Lisburne	Pt. McIntyre	Endicott	Milne	Niakuk	W. Sak	Beaufort	Total	
1992		1,260	310	40	0	110	19	0	0		1,739	(000) bpd
1993		1,190	310	40	20	94	17	0	0		1,671	"
1994		1,110	300	34	80	83	16	0	0		1,623	"
1995		1,110	280	27	80	72	16	20	6		1,611	"
1996		1,020	250	22	80	63	17	20	12		1,484	"
1997		922	220	17	80	55	18	20	12		1,344	"
1998		840	190	14	72	47	19	20	12		1,214	"
1999		765	170	11	65	40	20	17	25	0	1,113	"
2000		697	150	10	58	34	20	14	25	60	1,068	"
2001		633	125	9	52	29	18	12	50	54	982	"
2002		532	105	7	47	24	16	10	50	49	840	"
2003		479	90	5	41	21	14	9	75	44	778	"
2004		426	75	0	36	18	13	7	75	39	689	"
2005		383	65	0	30	16	12	6	75	35	622	"
2006		345	55		26	0	10	5	67	32	540	"
2007		293	45		22		8	5	61	29	463	"
2008		249	35		19		6		55	26	390	"
2009		212	30		16		5		50	23	336	"
2010		180	25		14				42	21	282	"
Total Barrels:		4,615,790	1,032,950	86,140	305,870	257,690	96,360	60,225	252,585	150,380	6,857,985	(000) bbls.)

Source Dept. of Natural Resources, "Historical and Projected Oil & Gas Consumption," April 1992, pp. 4-5 (Table 2.1: Production Forecast and Available Royalty Oil).

The retreat of production declines is a steady phenomenon that is readily observable in these data. For example, as recently as 1991 North Slope production was supposed to fall below one million barrels in the year 2000 (Table 5) — one year earlier than under the current DNR forecast. The source of the delayed decline is increased total production through the life of the North Slope fields.⁴

Table 7 presents North Slope total production estimates for selected years since 1985 through the first decade of the next century. In this table, North Slope production is divided into three periods: 1977-84, 1985-91, and 1992-2010.⁵ The left-hand column, which covers the 1977-84 period, contains actual production figures. The second column, covering 1985-91, contains a combination of oil produced and forecasted totals. For example, the 1990 figure in the 1985-91 column is the sum of the actual barrels produced from 1985 through 1989 plus the forecasted barrels for 1990-91. The total barrels forecasted for the 1992-2010 period appears in the third column. These are the totals at the lower right-hand corner of Tables 1 through 6. In the third column, the DNR April 1992 forecast estimates total production for this 19-year period at 6.86 billion barrels, compared to 6.51 billion barrels forecasted in 1991 and 5.82 billion in 1990. The 1992 estimate represents a 68.66% increase in total North Slope production compared to the 1985 forecast total of 4.07 billion barrels for the same period. Total production through 2010 in the fourth column is the sum of the first three columns.

While forecasted future production has increased, current production also increased. This can be seen in the second column of Table 7, where total production from 1985 through 1991 was 4.78 billion barrels — 13.54% greater than the 4.21 billion barrels forecasted for that period in 1985.

⁴ For a discussion of potential recovery techniques, see U.S. Congress, Office of Technology Assessment, Oil Production in the Arctic National Wildlife Refuge: The Technology and the Alaskan Oil Context. Washington, D.C.: U.S. Government Printing Office, February 1989 [Report #OTA-E-394].

⁵ In this analysis forecast figures are cut off at the year 2010 to reduce the effects of differing assumptions about shutdown that may produce unrealistic comparisons.

Table 7.

Changes in ANS Production Forecasts, 1985-1992

/ ===== Total ANS Production (all fields) ===== /

	(actual 000 bbls.)		(forecast and/or actual 000 bbls.)		(forecast 000 bbls.)		(forecast + actual 000 bbls.)
<i>Year of Forecast:</i>	<u>1977 - 1984</u>	+	<u>1985 - 1991</u>	+	<u>1992 - 2010</u>	=	<u>Total (1977-2010)</u>
1985	3,894,105	+	4,210,185	+	4,066,100	=	12,170,390
1988	3,894,105	+	4,781,704	+	4,427,815	=	13,103,624
1989	3,894,105	+	4,838,996	+	4,928,230	=	13,661,331
1990	3,894,105	+	4,723,021	+	5,823,575	=	14,440,701
1991	3,894,105	+	4,801,909	+	6,506,762	=	15,202,776
1992	3,894,105	+	4,780,297	+	6,857,985	=	15,532,387
% increase over 1985 forecast:	0.00%		13.54%		68.66%		27.62%

Source : 1977-84 from Dept. of Natural Resources, "Historical and Projected Oil & Gas Consumption," January 1985, p. 13;
1985-2010 from 1992 and previous issues of same publication.

The following table summarizes the changes in DNN production forecasts for the 1992-2010 period by field between 1985 and 1992.

Table 8.

**1985 v. 1992 State North Slope Production Forecasts by Field
(for 1992 through 2010)**

<i>Field:</i>	<u>1985 Forecast</u>	<u>1992 Forecast</u>	<u>1992 v. 1985</u>
	<i>/ = = million bbls., 1992-2010 = = = /</i>		<i>% increase (decrease)</i>
Prudhoe Bay	2,436.4	4,615.8	89.4%
Kuparuk	523.8	1,033.0	97.3%
Lisburne	206.2	86.1	(59.2%)
Pt. McIntyre	0.0	305.9	n.a.
Endicott	246.4	257.7	4.5%
Milne Pt.	16.4	96.4*	487.8%
Niakuk	0.0	60.2	n.a.
W. Sak / Beaufort	636.9	403.0	(36.7%)
Total	4,066.1	6,858.0	68.7%

* Milne Pt. 1992 estimate includes Schrader Bluffs production.

Source: Dept. of Natural Resources, "Historical and Projected Oil and Gas Consumption," January 1985 and April 1992 (tables 1 and 6, above).

The data presented here point out the importance of Prudhoe and Kuparuk, which account for the preponderance of the growth in future production forecasts. The data also point to a question of crucial importance to the future of the fields already under development. The incremental gain in total production between 1991 and 1992 was smaller than the gains of the three previous years. In 1989 the Congressional Office of Technology Assessment wrote that future increases in production from existing fields were liable to be relatively small because the industry had already ascended the Arctic learning curve.⁶ The increases in forecasted production since that time have proven OTA was at the least several

⁶ *Oil Production in the Arctic National Wildlife Refuge: The Technology and the Alaskan Oil Context* (op. cit.), pp. 12, 14.

years early in its conclusion. Is the relatively modest increase in the 1992 forecast totals an indication that soon technological gains will no longer offset future production declines, or will North Slope improved production techniques continue to defy the pundits and augment production?⁷

Standard & Poor's July revision of Prudhoe Bay's production prospects is the most recent indication from informed economic analysts that the OTA's bleak assessment has not yet come to pass. In upgrading the state's bond rating from "AA-" to "AA" (removing the "minus"), the credit rating agency cited three factors: state financial reserves, low and declining debt burden and "[c]ontinued extension of the north slope oil production curve as enhanced recovery techniques prolong the life of producing fields." According to Standard & Poor's, Prudhoe Bay was originally estimated to contain 9.6 billion barrels of oil but shipments to date have totalled nine billion barrels, with another 6.2 billion estimated to remain. Standard & Poor's reported Prudhoe shutdown date has been moved back ten years since its 1988 review, to 2016. The basis for its estimates was not given.⁸ Standard & Poor's estimates for Prudhoe are considerably higher than those of the state.⁹

Department of Revenue Senior Economist Chuck Logsdon offers little guidance about the shutdown of the North Slope. Once a field begins producing, his department's model simply lets the field produce as long as barrels remain in the ground that can be shipped to the Lower 48 for less than \$20.00 per barrel. When transportation hits that price, he figures, alternatives to North Slope oil will be found. Logsdon is not claiming that North Slope fields will produce all the barrels in the distant years his forecast shows. "You never know if that's how it's really going to turn out because there's a heck of a lot of things that can happen, and we've seen it happen," he once told an interviewer. "It's virtually impossible to forecast what's going on next year, and the farther you go out in time the greater your uncertainty."¹⁰

⁷ The question is similar to the conundrum that faces prospective buyers of computers, who have watched computers get better and prices drop year after year as technology continues to improve, seemingly without end. Can this trend continue? The answer depends on your understanding both the technology and the economics that apply to the question.

⁸ "State Review: Alaska," Standard & Poor's Creditweek — Municipal, Sept. 14, 1992, p. 1.

⁹ Alaska Department of Natural Resources, Historical and Projected Oil & Gas Consumption, April 1992, pp. 4-5 (Table 2.1: Production Forecast and Available Royalty Oil) and pp. 10-13, (Table 3: Historical Oil Production).

¹⁰ Alyson Pytte, "High Stakes Forecaster" Anchorage Daily News, Nov. 25, 1991 (interview), p. C-6.

It is widely recognized that the single most important factor affecting development decisions is the prospective producer's assumptions about future price of oil.¹¹ Nevertheless, increases in actual and forecasted North Slope production since 1985 have been logged in the face of forecasted prices significantly lower than those anticipated in 1985.¹² Is it possible that, contrary to conventional wisdom, price is not the most significant determining variable in production scenarios? Or is it that the North Slope induces inexplicably irrational behavior? A third possibility comes to mind: while price is in fact the most significant variable in the future of North Slope production, those operations may be so profitable that even today's relatively low prices provide ample profits to stimulate future production. We will return to price considerations in Chapter III.

B. West Sak: The Enigma Near Prudhoe Bay

Meanwhile, a second major area of concern emerges from the data presented above: the future of the West Sak field, a reservoir that contains an estimated 20 to 25 billion barrels of heavy oil in place and sits directly above the Kuparuk and Milne Point fields already in production.¹³ While West Sak nearly equals Prudhoe Bay in volume, industry observers have tended to write off the possibility of Prudhoe-scale production from West Sak due to the sandy content and relatively high viscosity of West Sak oil.¹⁴ Since 1990 both the Department of Revenue and the Department of Natural Resources have slashed forecasted production from West Sak.¹⁵ Nevertheless, since July 1991 at Milne Point

¹¹ U.S. Department of Energy in cooperation with the State of Alaska, Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity? (prepared by EG&G Idaho, Inc. under Dept. of Energy Contract # DE-AC07-761-D01570, January 1991), pp. 3-52 through 3-56.

¹² For example, the Department of Revenue's June 1985 forecast price for ANS on the West Coast was nearly \$50 per barrel in 1992 dollars — nearly twice the department's Spring 1992 mid-case West Coast forecast price of \$26.46. (1985 ANS West Coast price for 2000 from Alaska Department of Revenue, Petroleum Production Revenue Forecast, June 1985, p. 10; 1992 ANS West Coast mid-case forecast price for 2000 from Alaska Department of Revenue, Spring 1992 Revenue Sources Book, p. 17.)

¹³ In 1989 ARCO estimated 13 billion barrels in place with another 7 billion barrels listed as "potential" ("Kuparuk River Unit, West Sak Overview, AOGCC Presentation," August 21, 1989). A technical article published by the Society of Petroleum Engineers in 1988 estimated 25 billion barrels of heavy oil of 10.5-22.5 degrees API gravity (M.N. Panda, M. Zhang, D.O. Ogbe, V.A. Kamath and G.D. Sharma, "Reservoir Description of West Sak Sands Using Well Logs" [Society of Petroleum Engineers Bulletin No. SPE 18759, 1988], p. 1).

¹⁴ For a discussion of current West Sak issues see Allana Sullivan, "One Oil Field Environmentalists Want," Wall Street Journal, December 31, 1991, p. C-1.

¹⁵ The Alaska Department of Natural Resources cut its West Sak production forecast in half in 1991 to bring its forecast into line with the Department of Revenue's economic model (see Tables 4 and 5, above). In 1992 the Department of Revenue struck West Sak production entirely from its production forecast.

Conoco has been producing approximately 3,000 barrels of oil per day from its portion of the West Sak reservoir.¹⁶ Conoco's West Sak production is from the Schrader Bluffs formation, which lies directly above its Milne Point reservoir.

It is generally agreed that some form of enhanced recovery will be required to produce West Sak at rates sufficient to make recovery economically feasible. ARCO experimented on a pilot project for several years and determined that waterflooding is effective; laboratory work indicates that approximately 20 percent recovery rates can be achieved using hydrocarbon miscible injectant with a water-alternating-gas recovery process.¹⁷ Conoco has begun to waterflood Schrader Bluffs to augment production but has not yet been determined whether enhanced recovery techniques will boost production sufficiently to make Schrader Bluffs cost-effective.¹⁸ Per-well productivity gives a clear measure of the difficulties in producing West Sak. Conoco's wells are in the 300 barrel per day range, compared with 1,000 to 3,000 barrels per day from Prudhoe Bay and Kuparuk wells.¹⁹ There is another complication: conditions vary across the densely faulted West Sak field. Development will therefore require a variety of recovery techniques, making West Sak's potential more difficult to assess.²⁰ Nevertheless, Dr. G.D. Sharma, head of the University of Alaska's petroleum development laboratory in Fairbanks, believes a 25 percent recovery rate is possible, amounting to more than six billion barrels.²¹

Officials of ARCO, the major holder and operator of the West Sak field, believe the company will be able to produce a smaller but still significant fraction of its holdings at West Sak by making use of Kuparuk production facilities already in place. A similar synergy has been identified as critical to the economic viability of Conoco's West Sak production. In December 1991, ARCO offered the Wall Street Journal two versions of the

¹⁶ Alaska Department of Revenue, "Monthly Marketing Summary," July 1991 to date.

¹⁷ "Kuparuk River Unit, West Sak Overview" (presentations to Alaska Oil & Gas Conservation Commission, August 21, 1989 and Department of Natural Resources, August 23, 1989. See also: Patti Epler, "ARCO foresees West Sak Production: Field expected to produce up to 200,000 barrels daily by mid-1990's," Anchorage Daily News, Aug. 9, 1988.

¹⁸ Alan Hastings, Director Of External Affairs for Conoco's Alaska operations, personal communication, September 4, 1992.

¹⁹ Kathy Shirley, "Finding' Isn't the Same as 'Getting': West Sak Stingy With Treasures," AAPG Explorer, June 1992, p. 38.

²⁰ Alaska Oil & Gas Conservation Commission, "Conservation Order No. 255 [for] Kuparuk River Field, Milne Point Unit, Schrader Bluff Oil Pool," July 2, 1990, p. 2; Michael T. Lu, "A Simplified Approach to Steamflood Performance and Economic Feasibility Forecasting Calculations: Applications to the West Sak Reservoir" (University of Alaska, Fairbanks; unpublished Master's thesis, 1989), p. 192.

²¹ Sullivan, op. cit.

relationship between West Sak production and the utilization of facilities already in place to gathering, process and forward the oil to TAPS:²²

ARCO officials say they have examined Conoco's technique but claim it's an uneconomical method for them — its piece of West Sak is closer to the permafrost and therefore more viscous, they say. They claim Conoco can hold down its cost by moving the oil, once it's pumped to the surface, through facilities it is already using for another field [Milne Point] where there is additional capacity. ARCO also says that the strata that contains its piece of West Sak oil overlies its prolific Kuparak [sic.] oil field where there is no extra capacity. And as Kuparak production declines, West Sak will hopefully be phased in. ARCO also points out the daily flow rate at West Sak won't replace Prudhoe or Kuparak. [Emphasis added.]

A slightly different version of the story in the West Coast edition of the newspaper the same day said:²³

"The strata that contains its piece of West Sak oil overlies its prolific Kuparak oil field. And ARCO doesn't want to use any of those drill sites to move West Sak oil until Kuparak is drained dry sometime in the next century. [Emphasis added.]

In June 1992, the AAPG Explorer reported that ARCO estimates that 500 million to one billion barrels of oil are recoverable from West Sak:²⁴

"Daily production from the field will probably peak at 100,000 to 150,000 barrels a day," said James A. Middleton, executive vice president of ARCO.

"While these reserves are important to Alaska and certainly to ARCO, they obviously are nothing like the 1.3 million barrels per day currently produced at Prudhoe or, for that matter, what we might have expected out of the Arctic National Wildlife Refuge."

.... The West Sak Field does have one definite advantage — the extensive infrastructure of the Kuparak [sic] and Milne Point fields that can be used for developing the shallow field.

ARCO plans to co-mingle production from Kuparak and West Sak through the same gathering centers and pipelines, Middleton said. "As Kuparak declines, West Sak will increase."

[Conoco's Al] Hastings said the same is true at Milne Point.

²² Dow-Jones wire service, December 31, 1991.

The same synergy has been noted at Lisburne and Pt. McIntyre, where the existence of extra capacity in Lisburne's processing facilities contributes to Pt. McIntyre's economic viability by saving \$150 million (Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?, pp. 3-14-15).

²³ Sullivan, op. cit. According to environmental attorney Randall Weiner, former Executive Director of Trustees for Alaska, the Wall Street Journal carried different versions in different editions because ARCO representatives changed their statement on this key point on the date of publication.

²⁴ "Finding' Isn't the Same as 'Getting'" (op. cit.), pp. 38-39.

"It is so much cheaper to develop this shallow zone with an existing infrastructure," he said. "Frankly, if we had to build new facilities this zone would likely not be economic at all."

While production at the level ARCO personnel envision will not replace the super-giant Prudhoe Bay, production of 150,000 barrels per day would rank West Sak with the largest fields currently operating in the Lower 48.²⁵ More important, from Alaska's standpoint, is this: by sharing TAPS pipeline costs with other fields, West Sak production would reduce the TAPS shipping charge per barrel and therefore might extend production from other fields.

But don't start counting West Sak chickens just yet. Despite industry indications that a portion of West Sak's reserves will be produced, the Department of Revenue removed West Sak production altogether from its Spring 1992 revenue forecast. According to the DOR Spring 1991 forecast, at prices ranging between \$20 and \$30 per barrel during the first decade of the next century West Sak production would rise to 166,000 barrels per day. But one year later, the department's forecast showed no production at all from West Sak, even at high-scenario forecast prices from \$30 to \$58 dollars per barrel between 2000 and 2010.²⁶ Department of Revenue Chief Economist Logsdon said West Sak dropped out — perhaps temporarily — because forecast economic inputs were revised. He identified three major factors: (1) A higher target investment rate or hurdle rate of return was used in the Spring 1992 forecast model.²⁷ Under these tougher investment criteria, West Sak did not generate sufficient profit to warrant development. West Sak bombed out even though the department kept its facilities cost assumptions low, Logsdon said. (2) Logsdon said his unit is pessimistic about West Sak for many reasons, including Conoco's reported problems with sand and relatively low per-

²⁵ In 1989, the two largest fields in the Lower 48 each produced about 160,000 barrels per day (*Oil & Gas Journal*, Jan. 30, 1989, pp. 69-70).

²⁶ Alaska Department of Revenue, *Spring 1991 Revenue Sources Book*, pp. 35, 46-48; *Spring 1992 Revenue Sources Book*, pp. 34, 46-48.

In the Spring of 1991, the Dept. of Revenue's model forecasted West Sak producing 86,000 barrels per day at a low scenario price of \$20.63 in the year 2000, with production rising to 165,000 barrels per day in 2005. In the spring 1992 forecast, the low-case price was, coincidentally, \$20.63; but that forecast contained no West Sak production. In the Spring 1991 mid-case forecast, a price of \$29.46 in 2000 resulted in production of 92,000 barrels per day from West Sak; in the Spring of 1992, a price of \$30.80 in the high scenario resulted in no production from West Sak.

²⁷ According to Logsdon, in late 1991 the hurdle rate of return for West Sak was raised from 8% to 10% to bring the state's economic model more into line with the 12-1/2% figure used by the International Tax Comparison Study Group one year earlier. Since that group reported in April 1990, it is not clear why the Department of Revenue waited until late 1991 to reflect a higher hurdle rate of return for West Sak. Moreover, some industry sources believe that with the infrastructure for production already in place, a much lower hurdle rate of return is appropriate.

well production. (3) He also indicated that the department's production model does not include profits from TAPS in considering whether a prospective field should be added to the forecast. Since TAPS contains a healthy profit margin for its owners and ARCO is a major TAPS owner, the exclusion of profits from TAPS appears to penalize West Sak production unrealistically. Additionally, the Department of Revenue's scenario also fails to recognize that West Sak production would have a beneficial effect on all fields by spreading TAPS costs among a larger number of barrels.

In view of the questions and the apparent contradictions in information surrounding the massive amounts of West Sak oil, closer consideration of West Sak production economics is warranted. We will return to the economics of West Sak production after we examine the mechanics of North Slope accounting and estimate profits in the next chapter.

C. Information Regarding Production Decisions: The ELF Debate Revisited

Is Alaska's long, slow walk toward the evening of the petroleum production about to turn into a pell-mell dash, or will the twilight of North Slope operations continue to recede into the future? Will West Sak go into production, as ARCO comments to the press indicate, or will the Department of Revenue's more pessimistic view come to pass? As indicated above, at their root, these questions are economic. Both the economic model used to calculate returns and the information that is put into those models can prove crucial to conclusions about the feasibility of future development. Unfortunately, such information seldom reaches the public. Major North Slope producers preferring to deal with such issues in terms of over-simplified rhetoric rather than substantive economic data.²⁸ And although these matters are crucial to state revenues, in this atmosphere of closely held information and superficial rhetoric it is not clear that responsible state officials have sufficient information to evaluate industry production decisions.²⁹

Skepticism about those data the major North Slope producers are willing to share is re-enforced by comparing the constantly increasing production totals presented above to statements by North Slope officials during their efforts to thwart correction of a tax

²⁸ See notes 30 and 55, below.

²⁹ The Alaska Department of Revenue's Division of Oil and Gas Audit makes no claim to reservoir geology or engineering expertise. For this reason, the state's forecasters depend on information from the producers. The Department of Natural Resources' division of Oil and Gas and Alaska Oil and Gas Conservation Commission have more technical expertise on reservoir geology on staff, but these agencies are also highly dependent on the producers for their information.

provision known as the economic limit factor (ELF) in 1989. At that time, representatives of the major North Slope producers barraged legislators and the public with statements that "several hundred million barrels of oil could be left in the ground at Prudhoe if the ELF were modified."³⁰ State administration proponents of the ELF modification responded that because the proposed ELF would increase the tax break to truly marginal fields, the proposed tax correction was not liable to reduce future production. Shortly after the Legislature closed the loophole, ARCO announced cancellation of its West Sak pilot program and claimed the tax change could prohibit development of its Pt. McIntyre discovery. Meanwhile, BP stopped its Hurl State development at Prudhoe Bay. At the time, some industry observers dismissed the industry actions as political posturing.³¹ Whether or not that is the case, ARCO is in fact developing Pt. McIntyre at this time and BP subsequently went ahead with the Hurl State project. While West Sak remains in limbo, the assertion that the ELF revision had a significant impact on West Sak stretches credulity. As indicated above, technological factors and the price of oil are in fact the major factors affecting West Sak development. Moreover, ARCO's subsequent attempts to secure a tax advantage at Kuparuk in exchange for continuing West Sak development

³⁰ ARCO Alaska, "Where Do You Stand on ELF?" (insert in major Alaska newspapers, Feb. 17, 1989).

In response to a 1989 questionnaire from the House Resources Committee on the long-term effects on Prudhoe and Kuparuk, ARCO responded: "At Prudhoe and Kuparuk, [the proposed ELF revisions in] HB-118 will only make the next barrel of oil more expensive to produce and therefore it will be less likely to ever be produced. That means there will be more oil left in the ground. . . ." ("Response to House Resources Committee ELF Questions — HB 118" from Hugh R. Motley, then-Vice President and General Tax Officer, ARCO Alaska, to Reps. Curt Menard and Cliff Davidson, February 22, 1989, question 24; emphasis added.)

BP tax attorney Tom Williams made the same point, stating that "[t]he proposed changes are also ill-advised because the state stands to gain more from additional investment and development of Prudhoe Bay and Kuparuk than it will from any of the marginal fields [that might benefit from lower taxes due to a corrected ELF] But the new work in the [Prudhoe] field to add a hundred million barrels here, add a hundred million barrels there. . . . can become too expensive. . . . [c]hanges in the ELF changes the economic climate in which the decision to invest or not to invest is made. There's less money available, more is being paid in taxes . . ." (House Resources Committee transcript, Feb. 11, 1989, pp. 6-7, 13, 15; emphasis added.)

Throughout the spring of 1989, the industry's battle against the ELF continued. On April 20, an Exxon tax lawyer testified that the ELF revision's "increased cost of production would adversely affect investment in future Prudhoe Bay development projects . . . necessary to optimize production . . . After current development is completed, it is estimated that 10 billion barrels of oil will be left in formation at Prudhoe Bay. [The proposed ELF revisions in] H.B. 118 would increase the cost of producing those barrels and thereby reduce the incentive to undertake those projects." (Gerald Serena, testimony before the Senate Special Oil and Gas Committee, April 20, 1989, pp. 1, 3; emphasis added.)

³¹ According to a report by the investment firm First Boston, ARCO's reduced drilling activity was "at least partially the result of political posturing . . . to gain a reversal or modification in the Economic Limit Factor." (First Boston Equity Research, "Atlantic Richfield Company," Nov. 21, 1989, p. 1). For a summary of the ELF-related counterclaims, see Bill White, "The flip sides of ELF," *Anchorage Daily News*, August 6, 1989, p. C-1.

indicates that ARCO regards development-related discussions as a province for hard-ball negotiations rather than sharing of engineering and economic data for mutual benefit.³²

The sizeable increases in forecasted future production that have been logged since the closing of the ELF loophole in 1989 are summarized in Table 9. It is evident from this table that correction of the tax loophole has not led to reduced North Slope production, as industry opponents of the tax measure warned. Estimated future production has grown significantly in each of the annual state forecasts issued since the loophole was closed in 1989. The 1992 estimate for the 1992-2010 period of 6.86 billion barrels exceeds by 39.2% the 4.93 billion barrels forecasted for that period when the ELF correction was being debated in 1989. At the current North Slope production rate of approximately 1.7 million barrels per day, the 1.93 billion barrels of increased forecasted production over the next 18 years that have been added to North Slope production estimates since the ELF was revised represent three additional years of North Slope production ($[1.7 \text{ million barrels per day}] \times 365 \text{ days} = 620.5 \text{ million barrels}$; $[620.5 \text{ million barrels per year}] \times 3 \text{ years} = 1.875 \text{ billion barrels}$). As Table 9 makes clear, the preponderance of that increased production is at Prudhoe Bay and Kuparuk — in direct contradiction of the dire warnings by oil industry officials in 1989 that developments at those fields would be shut down and more oil left in the ground if the ELF loophole were corrected.³³

³² BP announced Hurl State development again in June 1990 (Oil & Gas Journal, June 18, 1990, p. 18); state forecasts anticipate production to begin at Pt. McIntyre in 1993. For ARCO's linking of West Sak development to a tax break at Kuparuk, see the Anchorage Daily News, February 21, 1990, p. A-1. These events were discussed in An Overview of North Slope Production Prospects, 1990-2010, pp. 26, 33.

BP recently noted in its international magazine that "The agreement [with other companies to develop Pt. McIntyre] paves the way for economic development of other, smaller accumulations nearby, because these deposits and Point McIntyre could be tied into production facilities now serving the neighboring Lisburne field." (BP Shield, Summer 1992, p. 24.) Asked to identify these fields, BP declined.

³³ As noted above, changes in forecast prices do not appear to explain the increases in production forecasts for the 1992-2010 period between 1989 and 1992. The Department of Revenue's long-range forecast prices for 1995 and 2000 were slightly higher in 1989 than in 1992 (Alaska Dept. of Revenue, Spring 1989 Petroleum Production Revenue Forecast, p. 6 and Spring 1992 Revenue Sources Book, p. 17).

Table 9.**1989 v. 1992 State North Slope Production Forecasts by Field**

<i>Field:</i>	<u>1989 Forecast</u>	<u>1992 Forecast</u>	<u>1992 v. 1989 Increase (Decrease)</u>	<u>% Change</u>
	/===== million bbls., 1992-2010 =====/			
Prudhoe Bay	3,189.7	4,615.8	1,426.1	44.7%
Kuparuk	554.8	1,033.0	478.2	86.2%
Lisburne	124.8	86.1	(38.7)	(31.1%)
Pt. McIntyre *	?	305.9	?	?
Endicott	209.9	257.7	47.8	22.8%
Milne Pt.	14.2	96.4 **	82.2	578.9%
Niakuk *	0.0	60.2	n.a.	n.a.
W. Sak / Other *	834.8	403.0	(431.8)	(51.7%)
Total	4,928.2	6,858.0	1,929.8	39.2%

* "Other" includes some Niakuk and Pt. McIntyre production

** Milne Pt. 1992 estimate includes Schrader Bluffs production.

Source: Dept. of Natural Resources, "Historical and Projected Oil and Gas Consumption," January 1989 and April 1992 (Tables 3 and 6, above).

In sum, the major North Slope producers argued that closing the ELF loophole would lead to reduced production by absorbing more of the capital that otherwise would be available for further development.³⁴ The data presented here indicate that the net increase in state tax collections caused by correcting the ELF did not have that effect. Why not? As in the case of the puzzle posed earlier — increasing future production despite lower prices — the answer to this mystery may be found by examining the unique economics of North Slope operations. We turn now to that task.

³⁴ It is possible that if the State had not opted to close the ELF loophole, production forecasts might have increased even more than the 39.2% increase logged in the last three years. By ignoring the fact that forecasted North Slope production was increasing, the industry spares the reader the necessity of considering this line of conjectural argument. The question before us in this section is whether the representations of the major North Slope producers during the ELF debate give cause for confidence in information presented by the industry when its economic interests are involved.

III. Analysis of Current and Future North Slope Per-Barrel Profits

A. Introduction

In this chapter we will attempt to delineate the profitability of North Slope crude oil by field in current price environments. We will also look at future scenarios. Our aim is to ballpark returns from the North Slope to the three parties who share the economic rent from these operations — the owner companies, the state and the federal government. The information we are seeking is not readily available from published sources or public records; profitability is not something the industry likes to discuss. Company annual reports are obscure, and even when they provide information on North Slope operations, one needs a magnifying glass to read the fine print and a detective with a degree in accounting to explain what the numbers include and what they leave out. The major North Slope operators were contacted but declined to provide cost information for this report.³⁵ In view of the importance of North Slope operations to the owner companies and the state, some may find the paucity of data in this area remarkable. We begin, therefore, with a review of available public information on North Slope profitability.

B. Sources

1. Newspaper reports

"Oil firms' profits up: Arco, Unocal report 3rd-quarter earnings," the Anchorage Daily News headlined recently.³⁶ What does the story tell us?

==> Arco's results outpaced the expectations of some industry analysts;

==> Arco earned \$332 million in the third quarter, compared with a loss of \$156 million for the same quarter the previous year. However, the previous year loss included a \$340 million one-time cost associated with restructuring and property sales.

==> Arco is the major gasoline marketer in the Los Angeles region and Arco (Alaska) Inc. is one of this state's top oil producers and a major owner in Prudhoe Bay.

³⁵ When the intention to build a model that would show prices, costs and the division of the economic rents from North Slope production was described to the ARCO tax specialist to whom the query had been referred, he responded that ARCO had no interest in providing that information. BP also declined to provide information (see note 54, below).

³⁶ Anchorage Daily News, October 27, 1992, p. C-1 (article from the Los Angeles Daily News).

This article, which is typical of newspaper quarterly earnings reports,³⁷ is not very useful to our quest. Since ARCO also has earnings from Lower-48 production, overseas production and Lower-48 marketing — not to mention coal, petrochemical and other operations — we will have to look beyond press coverage of industry's quarterly profit and loss reports for hard data on the economics of North Slope operations.

Earlier this year, The Anchorage Times tackled North Slope crude oil pricing in a lengthy business section feature. The article came up with a handy formula for estimating the State's per-barrel share of a barrel of North Slope crude: "just knock about \$5 off the per-barrel market price, and the state's royalty and severance tax share is about a quarter of what is left."³⁸ The Times article was a commendable effort to shed light on the complex mechanics of oil valuation. For example, it explained that the fields on the North Slope produce oil of different specific gravity and consequently have different value, and that the fields outside Prudhoe have additional pipeline tariffs to reach the TAPS line at Pump Station #1. In an effort to put all these figures into context (the article appeared on the eve of the anticipated court opening of the state's royalty case against Exxon for under-valuing North Slope crude oil; the case was settled on the courthouse steps and the trial never took place), the Times divvied up an \$18 barrel of oil for its readers in the following manner:

Market price	\$18.00
minus tanker cost	(\$1.00)
minus pipeline cost	(\$3.60)
minus Alaska's 1/8th royalty share	(1.68)
Oil industry's share plus 1/8th severance tax	\$11.73

Unfortunately, the analysis stopped there. The North Slope is quite profitable, but the industry's \$10.26 share — 7/8 of the remaining \$11.73 — does not represent profit. From that \$10.26 must come exploration and development costs, property tax, state and federal income taxes, exploration costs and development costs. By the time these costs are reckoned, the industry's profit is roughly half of the share indicated in the Times analysis, as we shall see below. When you're pumping 1.7 million barrels of oil per day, the difference between \$5 per barrel and \$10 per barrel adds up quickly.

³⁷ See, for example, "BP profits jump 67 percent," Anchorage Daily News, Nov. 6, 1992, p. C-1.

³⁸ Bert Tarrant, "The value of CRUDE: Every Alaskan has a stake in price of North Slope oil," Anchorage Times, April 12, 1992, pp. D-1, D-4.

The Times failed to note that the tariff or shipping charge for pipelining the oil includes a profit margin for the pipeline owners in excess of \$1.00 per barrel.³⁹ Since the major producers own TAPS in proportions roughly similar to their share of production, this is a profit element that needs to be reckoned with.

Clearly, we will have to look beyond press reports for a more refined analysis of North Slope profitability.

2. Trade Sources (Investment Analyses and Industry Publications)

From time to time in recent years, trade publications have examined North Slope profitability. In 1987 and 1988, for example, industry reports stressed the profitability of Prudhoe Bay and Kuparuk, even at low prices.⁴⁰ Of late there have been few North Slope profitability write-ups. However, two 1991 reports are noteworthy. In September 1991 the First Boston Company — a major investment banking firm — examined the U.S. operations of six major international oil companies to ascertain why the industry was heading overseas. Although the North Slope was not the focus of this report, First Boston did give Alaska special treatment. The data assembled by First Boston indicated that recent upstream returns on domestic operations had diminished radically, in marked contrast to overseas operations. First Boston concluded, "The domestic exploration and production business has not even come close to returning the cost of capital for the major oil companies over the last five years." The only international major that found U.S. operations more profitable than overseas, wrote First Boston, was BP:

"... [T]he trend is unmistakable. Except for British Petroleum, every company in this universe [of major international oil companies operating in the U.S.] generated substantially higher levels of profitability per dollar of net property, plant and equipment outside the United States than within this country."

³⁹ A 1989 accountancy study of North Slope profitability estimated that income from pipeline tariffs generated 30 percent of all North Slope profits for the North Slope producers (Edward B. Deakin, Oil Industry Profitability in Alaska, 1969 through 1987 [Alaska Department of Revenue, March 15, 1989], pp. 1-11). Except for Milne Point, whose major producer (Conoco) has no ownership in TAPS, the pipelines that bring the oil from the field to Valdez are universally owned by the producing companies.

⁴⁰ "Atlantic Richfield Company — Restructured and Resourceful," Salomon Brothers Inc. (stock research, domestic oils), April 28, 1987, p. 10; "Atlantic Richfield Company — The News Gets Better," Sept. 11, 1987, p. 7; "Alaskan Oil Profits Staying Buoyant Amid Volatile Prices," Petroleum Intelligence Weekly, Feb. 5, 1988, pp. 1-2; "Alaska's Oil Promise Remains Strong," International Petroleum Finance, Mar. 13, 1988, p. 8.

According to First Boston, BP's U.S. returns outpaced its foreign investments by 75%. In contrast, the U.S. investments of the other five major oil companies under-earned their foreign investments by significant margins. According to First Boston, the reason for BP's success in the U.S. is its North Slope operations. "Only those companies that produce oil from Alaska's Prudhoe Bay field," First Boston reported, "have been able to show above-average returns in the U.S. upstream sector."⁴¹

To explain the flight of capital and superior foreign returns, First Boston continued with a more detailed analysis of domestic production. First Boston reported that upstream domestic return on investment was "abysmal," with two exceptions: "Exxon has led the pack in the international oil universe with a stellar 6.2% return on investment," First Boston wryly observed. Nobody else in the international group earned better than a 4% return on U.S. upstream operations over the five-year period.⁴²

The second exception was ARCO, which First Boston added to the domestic analysis "to highlight the fact that Alaska is the only part of the country in which producing operations have provided attractive returns over time." Wrote First Boston:

ARCO's Alaskan properties have generated an 11.4% return on investment over the last five years — clearly a multiple of what the lower 48 producers enjoyed. If one were to look at only the last four years in this time series, deleting the disastrous 1986 results which coincided with the collapse in world oil prices, ARCO's average ROI from Alaskan operations would have been 13.5%.

First Boston estimated that over the five years from 1986 through 1990 ARCO averaged a per-barrel profit from Alaska production of \$2.70. The contrast between ARCO's handsome domestic profits and the paltry returns of other companies was so sharp that First Boston isolated the ARCO data from other companies in special boxes.⁴³

The First Boston per-barrel data suffers from two major shortcomings that result in significant understatement of North Slope profits. The first is that the First Boston data

⁴¹ First Boston Equity Research, "Assessing the Domestic Operations of International Oil Companies: Explaining the Exodus of Capital," September 5, 1991, pp. 2, 4, 10.

⁴² "Assessing the Domestic Operations of International Oil Companies: Explaining the Exodus of Capital," p. 5.

⁴³ "Assessing the Domestic Operations of International Oil Companies: Explaining the Exodus of Capital," pp. 5, 12-13. (First Boston had to drop BP from this portion of its analysis because BP's financial data was not reported in such a way that its upstream operations could be compared to domestic companies.)

excludes pipeline profits. ARCO officials doubtless remember to take their Alaska pipeline profits to the bank.

The second problem is that First Boston's 1991 estimates relied on data from company annual financial reports. Some analysts do not consider annual report data a reliable indicator of company profitability. In any given year annual report data can be very misleading due to the practice of shifting gains and losses to other years to reduce taxes, as ARCO's did in the third quarter of 1991.⁴⁴ The purpose of such creative but legitimate bookkeeping shifts is to reduce income for tax purposes; the over-all effect may be to reduce the apparent bottom-line profit.

One need not regard First Boston's 1991 profit estimates as definitive to accept the investment company's conclusion that the profitability of their Alaska operations set ARCO and BP apart from other oil companies who find greater profits overseas.

The second recent trade analysis of North Slope profits is a June of 1991 report on ARCO by the oil stock research department at Salomon Brothers. While Salomon's updated review of ARCO's profitability is more detailed than First Boston's, the Salomon Brothers model also excludes key elements that are necessary to a complete analysis of per-barrel profitability. Because Salomon's interest is limited to trends in ARCO's profitability, data needed for a complete reckoning of North Slope profits are not provided. For starters, Salomon model profit figures are reckoned on ARCO's company-owned barrels. This means royalty barrels and royalty payments are excluded from this analysis. Moreover, the costs and profits of other producers — which may be different from ARCO's — are not considered. Additionally, Salomon Brothers — like the Anchorage Times — makes no provision for property tax or state and federal income tax payments. Finally, Salomon, like the other analyses we have seen, treats pipeline tariffs as a cost of oil production. Despite these shortcomings, the Salomon analysis provides a basis for trends in North Slope production costs and profitability through time. We will return to Salomon's production cost estimates later in this chapter.

⁴⁴ See: "Oil firms' profits up," op. cit. See also: Robert Brandon, Edwin Rothschild and Robert McIntyre, Oil Company Profits: What They Mean and Where They Go (Washington, D.C.: Citizen/Labor Energy Coalition, Energy Action Education Foundation and Tax Reform Research Group, Nov. 14, 1979), passim. In the past First Boston has done more detailed analysis of North Slope production economics.

3. State Data

The Alaska Department of Revenue analyzes field profitability to generate its semi-annual revenue forecast. However, the only data published from this effort are the estimated production by field, the forecasted price and transportation charges and the total revenues the state anticipates in production, property, conservation and income taxes, and in royalties. The department also maintains a smaller model, known as "Shortcut." This model, which can be run on a personal computer, revises the forecast monthly as revenues are collected and shows how state revenues from oil production will vary with the price of oil. However, Shortcut provides no information on property tax, state income tax, federal income tax or corporate profits. And, once again, Shortcut provides no data on pipeline profitability. Nevertheless, if you're into the field costs that are deducted from the wellhead for royalties or the ELF for a particular field, you'll love Shortcut.

In 1989 the Department of Revenue commissioned a pioneering study of oil industry profitability. That report, by Professor Edward B. Deakin, Price Waterhouse Centennial Professor of Accounting at the University of Texas, was published the week before the Exxon Valdez hit Bligh Reef. By culling various financial statements and Department of Revenue data, Deakin estimated North Slope production and pipelining profits after taxes between start-up in mid-1977 and the end of 1987 of \$41.5 billion, or nearly \$4 billion per year.⁴⁵ Deakin estimated per-barrel profits between \$2.26 (1977) and \$9.86 (1984).⁴⁶ Perhaps more important for this analysis, Deakin estimated the breakdown of economic rent on North Slope production and pipeline operations during the first 10-1/2 years of production as follows:⁴⁷

State Share:	\$27.6 billion	29.4%
Federal Share:	\$24.6 billion	26.3%
Industry Profit:	\$41.5 billion	44.3%

⁴⁵ Oil Industry Profitability in Alaska, 1969 through 1987 (op. cit.), pp. i-ii.

⁴⁶ From Oil Industry Profitability in Alaska, 1969 through 1987, Appendix E. Deakin divided estimated after-tax income for working interest barrels, excluding royalty barrels. This report, on the other hand, will delineate economic rent in terms of total barrels produced, including the royalty shares. For consistency with the methodology used in this report, Deakin's numbers have been adjusted to spread industry profits across total production, including royalty barrels. (Deakin's figures were \$2.58 for 1977 and \$11.27 for 1984.)

⁴⁷ From Oil Industry Profitability in Alaska, 1969 through 1987, pp. 3, 5, 9.

Deakin's work, which represents the only comprehensive analysis of North Slope profits this writer has been able to locate, has not been updated.

Several other state agencies keep track of reported costs and income that relate to the piece(s) of North Slope operations for which that agency is responsible. However, no other agency makes North Slope economic information public in any manner that can be called comprehensive.

C. Setting Up a Per-Barrel Profitability Model

Having described briefly the kinds of information available on the subject of North Slope, we turn now to the task of setting up a model that answers the question: How much do the oil companies make per barrel on their North Slope operations?⁴⁸ Each period under consideration begins with a table that summarizes North Slope production economics for a barrel of oil produced during the period in question. The summary table is followed by a similar table for each of the producing fields that comprise total North Slope production. The format for every table is identical; the model contains 23 lines, numbered at the left and captioned. The value for each line is given for ANS at the Gulf Coast and the West Coast, followed by a note in the right-hand column identifying the source of the data.

⁴⁸ To determine the attractiveness of a given project, industry planners makes use of several modes of economic analysis. At center stage would be a net present value (NPV) calculation that describes the worth of a project after taking into account the time value of money. NPV is measured by the income a project makes over and above inflation and a discount rate that represents the rate the money might earn invested elsewhere. Analysis of return on investment — how much is the project going to earn on each dollar spent? — and the timing — will the project pay for itself in one year or ten? — are also critical factors. Typically, these performance measures cannot be considered in isolation. A project requiring a large investment and a long development time must have a high rate of return to compete with projects that require less investment and pay out more quickly. (For a discussion of these approaches, see Alexander Kemp, David Rose, Peter Gaffney and H. Motamen Scobie, *International Oil Tax Comparison Study*, prepared for the Alaska State Legislature and the Department of Revenue, April 1990, pp 5-7, 15. Department of Revenue analysts Roger Marks and J. William Moore described the department's model in "A Model to Assess Economic Feasibility and Optimum Production Volume for North Slope Fields," in *Journal of Petroleum Technology*, Aug. 1987, pp. 943-954. "Economic Feasibility of Potential Fields" and "The Relationship of Production Volume to Price," in Dept. of Revenue, *Petroleum Production Revenue Forecast*, June 1985, pp. 42-48. Unfortunately, NPV analysis — which looks at expenditures and receipts and the value of that money at the time that it is paid out from or received by company coffers — requires a great deal of investment data that is not publicly available. Primarily for this reason, NPV modelling itself is beyond the limited resources available for this project.

A second approach is the accountancy method applied by Deakin (*op. cit.*). This approach uses standard accounting tools and depends on making certain informed assumptions about data contained in corporate annual reports, federal Security and Exchange Commission reports and other documents. An accountancy background is required to execute this approach.

A third approach — the one used here — is to begin with the market price per barrel and identify all costs as accurately as possible. While this approach is less sophisticated, the model's assumptions cannot feed on themselves. Additionally, the model is transparent to the reader.

We turn now to a line-by-line consideration of the model.

1. Price

a. Spot v. Contract Prices: The price used here is the average spot market price for ANS at the Gulf and West Coasts. In the early years of North Slope production the spot market price did not track the contract price at which most ANS was sold or transferred from a North Slope company's producing arm to the refining arm. In recent years, however, the spot price has become an increasingly accurate proxy for the value of ANS. One indication of its accuracy is that the state now uses the reported ANS spot price as one of its basic indices for both tax and royalty calculations.⁴⁹

b. West v. Gulf Prices: The West Coast price is typically about \$1.00 per barrel lower than the Gulf Coast price. The reason usually given for this difference is that the West Coast price is driven down by the surplus of oil on the West Coast created by the export ban on North Slope crude.⁵⁰

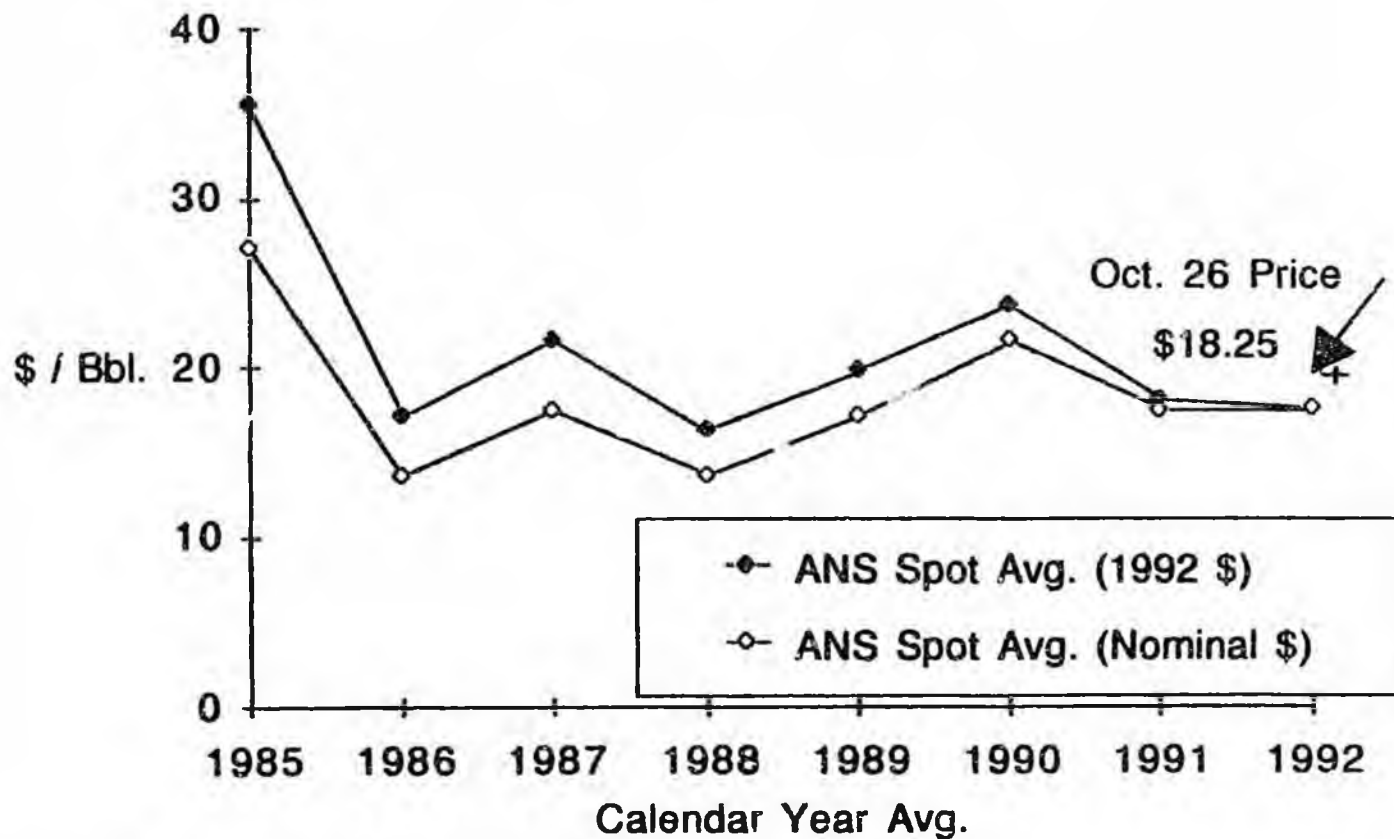
c. Price Trends. After the price spike at the end of the 1970's, ANS held fairly steady in the \$27 range between 1982 and 1985, when the price crashed at year-end. Rebounding from its lows near \$10 in early 1986, prices began working their way back up, only to fall again in late 1988. In the last four years, ANS has averaged slightly over \$17 on the West Coast, except for the six-month spike following Iraq's occupation of Kuwait in August 1990. In Graph 1, the average calendar year West Coast spot price since 1985 is charted in nominal and inflation-adjusted or real (1992) dollars. Annual average inflation-adjusted West Coast prices appear to be travelling nearly dead-level over the last six years.

⁴⁹ For an example of a valuation formula using spot prices, see "ANS Royalty Settlement Agreement" between ARCO and the State of Alaska, Sept. 12, 1990, Par. III.A.3. Subsequent settlements with BP and Exxon use a similar formula.

⁵⁰ It has also been argued that the West Coast market has been depressed by collusion of the major producers. Despite the fact that the state's royalty and severance payments for West Coast oil are tied to the West Coast price, the state's oil litigation attorneys have shown a marked disinterest in the law suits that have alleged price-fixing in the West Coast crude oil market.

Graph 1.

**ANS Weighted Avg. Spot Price
(Nominal and 1992 \$)**



Source: Nominal Weighted Spot Avg. from DOR
(1992 thru September)

2. Quality Adjusted Price

This adjustment is made for individual fields; no adjustment is necessary for the average ANS price. Refiners pay a premium for light-weight oils that will produce greater quantities of more valuable motor fuel-grade products; heavier grades are discounted. Prices are also adjusted for sulfur content and other impurities. This line adjusts each field's estimated market price for the quality of the oil produced in that field. Lisburne and Prudhoe Bay oil weigh in above the North Slope average; Endicott, Kuparuk and Milne Point fall below the average.

3. Production and Disposition

Production is totalled in millions of barrels by year and day in line 3(a); in line 3(b), the percentage of oil to the West Coast and Gulf Coasts is estimated by dividing the difference between the weighted average price and the West Coast price by the difference between the West and Gulf Coast prices.⁵¹ In 1992, approximately four out of every five barrels goes to the West Coast — up from a 50-50 split six years earlier. The Department of Revenue forecasts that by 1996 it will be possible to dispose of all ANS on the West Coast.

4. Feeder Pipeline Tariffs

By convention, the pipes that bring oil from the fields outside Prudhoe Bay to the head of the Trans-Alaska Pipeline System are treated as pipelines whose costs are subtracted from the market price for royalty and tax calculations and whose profits are reckoned separately from production. The components of the feeder tariff that comprise line 4 are presented in lines (a) through (g). Where they are known and available to the public, the elements of the feeder line tariffs were provided by the Department of Law. Where these data were not available, estimates were made.

Since more than 75 percent of all North Slope production — Prudhoe and Lisburne production — do not use feeder lines, the composite feeder-line tariff, when averaged across all barrels, reduces the wellhead value by an average of only \$0.09 per barrel. The

⁵¹ The owners consider even the most basic information on marketing proprietary and only one company — BP — markets on the Gulf Coast. For this reason, the East/West breakdown must be estimated in the manner described here.

\$0.00 entries at lines 4[b], 4[c] and 4[g] indicate weighted average entries of less than \$0.005 (one-half cent) per barrel. However, this weighted average reduction to the composite wellhead price of the North Slope crude oil masks the importance of the feeder line tariffs to the individual fields whose oil must bear feeder line shipping costs. Three such pipelines are in operation on the North Slope: Milne Point, Kuparuk and Endicott Pipelines. Each is owned by the producers of the field the pipeline was built to serve. The Kuparuk tariff is \$0.21 per barrel, while Endicott's is \$0.71 and the Milne Point Pipeline carries an \$0.78 tariff. Milne Point producers also pay an additional \$0.21 to use the Kuparuk Pipeline to complete its shipment to TAPS.

Because the settlement of the Kuparuk Pipeline tariff dispute in 1991 did not provide a breakdown of tariff elements, that the ratio of each line to the total tariff for TAPS was applied to the Kuparuk tariff of \$0.21 per barrel.

The Endicott Pipeline tariff is the subject of a dispute before the Federal Energy Regulatory Commission (FERC) between the state and the Endicott owners; for this tariff, cost elements (lines (a), (b), (f) and (g) lines are taken from the State of Alaska's cost of service estimates. The remainder is divided among lines (c), (d) and (e) using the methodology for TAPS described in the following section.

Milne Point Pipeline tariff elements were provided by the Department of Law. Because the Milne Point owners have no ownership share in the Kuparuk or TAPS pipelines that carry oil from Milne Point to Valdez, economic rents from Milne Point's share of the TAPS and Kuparuk tariffs require special treatment in this model. Because TAPS profits accrue to the TAPS owners and not to the Milne Point shippers, TAPS profits from line 11 are not included in Milne Point profits at Line 22; however, Milne Point oil's share of state and federal taxes on TAPS — paid by the Milne Point owners and transferred to the taxing authorities — is included at lines 20 and 21. Kuparuk Pipeline costs and income, like that of TAPS, accrues to the owners of Kuparuk, not to the Milne Point producers. But to reflect the Kuparuk tariff in our model, different treatment is required to distinguish between the Kuparuk feeder line tariff that Milne Point pays out and the Milne Point tariff, whose costs and profits are paid directly to the Milne Point owners. The Kuparuk tariff is therefore subtracted from the price of Milne Point oil at line 13 to produce the wellhead value; the economic rents for Milne Point oil shipped through the Kuparuk pipeline are tallied on a separate sheet (G).

The next section contains a brief discussion of the specific elements that comprise the feeder and TAPS tariffs.

5. TAPS Pipeline Tariff

The costs of building and operating the 800-mile trans-Alaska Pipeline system are covered in the TAPS tariff. Like the feeder lines, the TAPS tariff contains profit elements for its owners and is subtracted from the market price for royalty and tax calculations. The TAPS tariff on line 5 is the sum of the eight lines below it, identified as lines (a) through (h). These lines cover the following elements:

⇒ Line (a) totals operating costs and capital repayment.

⇒ State and local property taxes identified in line (b) were not isolated by the Department of Law but were included in operating costs. To estimate these tax payments to the state it was assumed that pipelines generate 30% of all state and local property taxes; this fraction was pro-rated to the specific pipeline tariffs in line (b). Line (b) totals, in turn, were subtracted from line (a).

⇒ Total income tax payments reported by the Department of Law were separated into state income tax on line (c) and federal income tax on line (d). The division between state and federal tax is based on an assumed federal tax of 25 percent and a state tax of 3 percent of net income.

⇒ Pipeline tariffs contain two profit elements, the after-tax margin (e) and recovery of deferred return (f). The latter element is identified separately in these tables because it is often overlooked in reports of pipeline profits.

⇒ Line (g), the fee charged for pipeline dismantling, removal and restoration (DR&R), is separated from operating charges to reflect its unique nature as an advanced collection for possible future expenditure.⁵² Although the pipeline owners retain possession of the DR&R sums they have already collected, company officials tend to speak as if these funds didn't exist.⁵³ In fact, the DR&R requirement may be a significant factor

⁵² For information on the extraordinary profitability to the TAPS owners of DR&R, see the author's Hidden Billions: The TAPS DR&R Provision (report prepared for Stan Stephens, Valdez Alaska), Aug 21, 1992.

⁵³ For example, speaking at an international conference on energy issues in Anchorage in July 1992, Alyeska Vice President M.F.G. Williams pointed out that "there comes a time when all of those small costs (on environmental measures) become factors in future operating or investment decisions." Williams then hopped nimbly to his experience in coal mining to suggest that foreign coal producers seemed to undercut their U.S. competitors "by the amount we had to pay to the U.S. for end of mine reclamation." (M.F.G. Williams, "Economic Regulations and Development," presented at the University of Alaska Anchorage School of Business and Organization of Petroleum Exporting Countries conference, July 23, 1992, p. 2.) Mr. Williams omitted mention of the fact that TAPS owners have already amassed a small fortune for this purpose through the liberal terms of the 1985 TAPS tariff settlement, or the fact that this money is subtracted from calculation of the profits Alyeska and the North Slope producers are earning before those profits are calculated. This windfall to Mr. Williams' employers is estimated at \$300 to \$400 million per year over and above the marketing profits normally attributed to Alaskan oil production and pipelining. (For estimated 1992 profit to the owner companies, see Hidden Billions: The TAPS DR&R Provision, at pp. 23, 26.)

in extending North Slope production because the DR&R requirement may encourage the owners to delay shutdown of North Slope operations in order to defer payout of these funds. When it can no longer be delayed, the outlay of DR&R funds and the loss of earnings from these funds will add up to a cash drain on the owner companies of hundreds of millions of dollars per year.⁵⁴ Nevertheless, the value to the owners of delaying these expenditures is overlooked in most North Slope economic models.

==> Line (h) adjusts the tariff by field for the additional pumping costs attributed to oil with higher specific gravities (lower API numbers) than Prudhoe Bay crude oil. For example, Kuparuk oil is heavier than Prudhoe oil and therefore pays a pumpability fee of \$0.29 per barrel; Lisburne's oil is lighter and therefore realizes a tariff reduction.

Lines 6 through 8

These lines subtotal the economic rents from the feeder tariffs to the state (line 6), the federal government (line 7) and the industry (line 8).

Lines 9 through 11

These lines subtotal the economic rents from the TAPS tariffs to the state (line 9), the federal government (line 10) and the industry (line 11).

Line 12

This line represents the estimated tanker costs to the Gulf or West Coast. Because reported data is deemed confidential, this report uses the industry charter rates published by the United States Freight Rate Association (USFRA). It should be noted that the tanker element contains a profit, but all profits downstream from Valdez are excluded from this analysis.

Line 13

The wellhead price is the crude oil price (line 1 or 2) minus the total transportation charge (lines 4, 5 and 12). This is the starting point for calculating royalties, state and federal taxes. It is here that the West Coast barrel, which began with a lower market price than its Gulf Coast counterpart, becomes more valuable. The reason for the higher wellhead value of West Coast crude is not hard to find: West Coast oil has a lower tanker

⁵⁴ Hidden Billions: The TAPS DR&R Provision, pp. 32-36.

charge at line 12 than Gulf Coast oil, reflecting the shorter trip from Valdez to the West Coast.

Line 14

Line 14 is the sum of state royalty (a), severance tax (b), spill response and conservation tax (c) and state and local property tax on production (d).

(a) Royalty, paid to the state as landowner under AS 38.05, is a fixed percentage of the wellhead price less field costs, which average approximately \$0.70 per barrel. The state's royalty percentage is 12.5% for Prudhoe Bay, Kuparuk and Lisburne. Endicott pays approximately 14.45%, while Milne Point's royalty is 18.35%. While the state can and does take some of its royalty and sells it directly, the majority of royalty is disposed of by the owner companies, who then pay the state. This model treats all barrels as if the owner companies dispose of the oil and make the appropriate payment to the state.

(b) The severance tax paid under AS 43.55 is a fixed percentage of all working interest or non-royalty barrels. The severance tax is 15% for Prudhoe and Kuparuk and 12.25% for the other producing fields. Severance has one major adjustment: the ELF, discussed above. The effect of the ELF will be clear when we look at the severance paid on oil from the relatively less profitable fields, such as Lisburne and Milne Point, at different prices.

(c) The spill response tax of \$0.05 per barrel, enacted after the Exxon Valdez spill and the conservation tax of \$0.004 per barrel apply, like the severance tax, to non-royalty barrels.

(d) State and local property taxes collected under AS 43.56 are derived by dividing the total reported tax by the number of barrels produced during the period under consideration. In this model, it is assumed that 70% of the property tax applies to production and 30% applies to pipeline. (lines 4 [b] and 5 [b]).

Line 15

Line 15 is the sum of (a) lifting costs and (b) capita' expenditures, which are recovered through depletion, depreciation and amortization (DD&A). Since the producer does not directly control the world price of oil, transportation costs and the tax regime, production costs are a key variable that can determine whether production is economically viable. The North Slope producers are reluctant to provide information about this

important aspect of production.⁵⁵ The only per-barrel production cost estimates available since the Middle East crisis of 1990-1991 come from Salomon Brothers. The estimates are contained in the investment firm's estimates of Prudhoe and Kuparuk profitability through 1995, last published in June 1991.⁵⁶ While it is widely assumed that it costs more to pull each barrel of oil from the ground as the North Slope fields age, this trend is not evident from Salomon's estimates.⁵⁷

⁵⁵ A senior official at BP said he could provide one piece of the North Slope production economics puzzle for this report: BP's lifting costs. But first, he said, he had to coordinate with other persons within BP who were working on a new advertisement. The data were not provided and did not appear in the advertisement.

A recent BP advertising campaign did offer an over-simplified picture of recovery techniques such as gas injection and fracturing, but the ads contained no substantive information on production costs. (BP Exploration [advertisement], "How Intentional Fracturing Actually Speeds Recovery," *Anchorage Daily News*, Oct. 8, 1992, p. B-6, and "Our Latest Investment is an Absolute Gas," *Anchorage Daily News*, Oct. 13, 1992, p. B-4.) Although its treatment is superficial, at least BP is discussing its operations. A recent ARCO advertisement contains a picture of Sacajawea guiding Lewis and Clark and this message: "Modern exploration depends on local knowledge. Cooperation. And learning everything we can about the land and sea. And as we look ahead to our future, we salute Lewis and Clark . . ." (ARCO Alaska [advertisement], "Local support goes a long way," *Anchorage Daily News*, Oct. 3, 1992, p. C-2.)

⁵⁶ Salomon Brothers, "Atlantic Richfield Company — Prudhoe Redux," (Stock Research: Oils) Oct. 19, 1990, p. 5; "Atlantic Richfield Company — Hitting a Rough Patch," (Stock Research: Oils) June 25, 1991, p. 5. Sources at Salomon say the company is not keeping its ARCO model current at this time.

⁵⁷ In view of the paucity of published data in this area, it may be worth noting that during the late 1980's Salomon Brothers production cost estimates were consistent with other public estimates from industry and trade sources at that time:

<i>Source:</i>	<i>First Boston</i>	<i>Salomon Bros.</i>	<i>Petro. Intel. Weekly</i>	<i>International Petro. Finance</i>	<i>BP</i>
<i>Estimate Date:</i>	4/86	4/87-9/87	2/88	3/88	2/89
<i>For:</i>	1986	1988	1988	1988	1988
<i>Field / Item</i>					
Prudhoe Bay —					
Lifting	\$1.00	\$0.85		\$0.63	
DD&A	\$1.85-\$2.28	\$1.85		\$1.68	
Totals	\$2.85-\$3.28	\$2.70		\$2.31	
Kuparuk —					
Lifting		\$1.80		\$0.76	
DD&A		\$3.65		\$3.37	
Totals		\$5.45		\$4.13	
All Fields —					
Lifting					
DD&A					
Totals			\$3.10		\$3.39

Table 10.**Estimated ARCO Lifting and Amortization Costs, 1992 through 1995***(Estimate Published: October 1990 and June 1991)*

	<u>1992</u>	<u>1993</u>	<u>1994</u>	<u>1995</u>
Prudhoe Bay				
Lifting	\$0.95	\$1.00	\$1.00	\$1.05
DD&A	<u>\$1.80</u>	<u>\$1.80</u>	<u>\$1.80</u>	<u>\$1.80</u>
Total	\$2.75	\$2.80	\$2.80	\$2.85
Kuparuk				
Lifting	\$1.70	\$1.75	\$1.80	\$1.85
DD&A	<u>\$3.30</u>	<u>\$3.30</u>	<u>\$3.30</u>	<u>\$3.30</u>
Total	\$5.00	\$5.05	\$5.10	\$5.15

Source: Salomon Brothers, "Atlantic Richfield Company — Prudhoe Redux," (Stock Research: Oils) Oct. 19, 1990, p. 5; "Atlantic Richfield Company — Hitting a Rough Patch," (Stock Research: Oils) June 25, 1991, p. 5.

It appears that the Salomon model held production costs steady except for a slight increase in operating costs to cover inflation.

While Salomon's estimate of lifting costs increased slightly for production in 1992 as compared to 1990, it is significant to note that the current estimate of ARCO's production costs is significantly less than the investment firm anticipated five years ago. The following table considers Salomon Brothers' production cost estimates for production in 1990 and 1992, as estimated in 1987 and re-estimated in 1990.

Table 11.**Salomon's Estimated ARCO Lifting and Amortization Costs, 1990 and 1992**

<u>Estimate Date:</u>	<u>4/87 and 9/87 (a)</u>	<u>10/90 and 6/91 (b)</u>
<u>For Production Years:</u>	1990 - 1992	1990 - 1992
Prudhoe Bay —		
Lifting	\$0.95 - 1.05	\$0.95 - \$0.95
DD&A	<u>\$1.95 - 2.05</u>	<u>\$1.80 - \$1.80</u>
Totals	\$2.90 - \$3.10	\$2.75 - \$2.75
Kuparuk —		
Lifting	\$1.90 - \$2.00	\$1.65 - \$1.70
DD&A	<u>\$3.85 - \$4.00</u>	<u>\$3.30 - \$3.30</u>
Totals	\$5.75 - \$6.00	\$4.95 - \$5.00

Source:

(a) Salomon Brothers, "Atlantic Richfield Company — Restructured and Resourceful," (Stock Research: Domestic Oils) April 18, 1987, p. 10; "Atlantic Richfield Company — The News Gets Better," (Stock Research: Domestic Oils) Sept. 11, 1987, p. 6.

(b) Salomon Brothers, "Atlantic Richfield Company — Prudhoe Redux," (Stock Research: Oils) Oct. 19, 1990, p. 5; "Atlantic Richfield Company — Hitting a Rough Patch," (Stock Research: Oils) June 25, 1991, p. 5. (Note: Lifting cost and DD&A estimates are identical to the company's previous estimate, published in October 1990.)

This table shows that in 1987 Salomon Brothers estimated that 1992 per-barrel lifting and amortization costs for Prudhoe Bay would total \$3.10 per barrel; three years later, the 1992 per-barrel estimate for Prudhoe production was reduced more than ten percent, to \$2.75. Similarly, over the same period, Kuparuk cost estimates for 1992 were reduced from \$6.00 per barrel to \$5.00. Thus near-term field production cost estimates tended to drop between 1987 and 1990-91. Although Salomon does not discuss the basis for its estimates, the cost-reduction may be attributed to three factors: (1) production of additional barrels of oil against which field costs can be charged, (2) cost-saving technological applications and (3) cost-saving management measures.

Viewed together, these two tables indicate that the price of more expensive recovery techniques is likely to be off-set, at least in part, by cost reductions.

To estimate current and past-year lifting costs, the following table uses Salomon Bros. data for Prudhoe Bay, Lisburne and Kuparuk. Because Salomon was reporting on

ARCO, its analysis did not provide data for Endicott and Milne Point. For those fields, field costs are derived from comparative data on operating costs per barrel of fluids provided by EG&G Idaho in its 1991 report to the U.S. Department of Energy.⁵⁸ For DD&A costs in current and prior years, Salomon data are used when available. For Endicott and Milne Point, the EG&G operating cost factor is applied to Salomon Brothers data for the available fields.

Line 16

Net revenue (production) is the wellhead value less the state royalty and taxes identified in line 14 and ande production costs from line 15.

Line 17

State income tax per barrel is calculated by dividing total collections reported by the Department of Revenue under AS 43.20 by total barrels produced. The portion allotted to pipelines in lines 4(c) and 5(c) is subtracted from the per-barrel total in line 17. Since state income tax is based on world-wide production and income factors rather than North Slope operations, the figures here are not adjusted to reflect higher West Coast per-barrel profits.

Line 18

Federal income tax is calculated at 32.1% of net revenue less state income tax. It is likely that the average federal income tax paid by North Slope producers is significantly lower. A 1984 study found the North Slope's three major producers paid an average of 23.25% in federal income taxes between 1981 and 1983. In a 1988 update to that study, ARCO and BP were not reported but Exxon paid approximately 23% from 1981 through 1987.⁵⁹ For this line the more conservative 32.1% figure that Deakin reported for the 1977-87 period is used.

Line 19

Industry profit on production equals net production revenue (line 16) minus state and federal income taxes (lines 17 and 18).

⁵⁸ Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity? (op. cit.), p. 3-16.

⁵⁹ Robert S. McIntyre and Robert Folen, "Corporate Income Taxes in the Reagan Years: A Study of Three Years of Legalized Tax Avoidance" (Citizens for Tax Justice, 1984), pp. 32-33, 36; Robert S. McIntyre, Jonathan M. Crystal and David C. Wilhelm, "The Corporate Tax Comeback" (Citizens for Tax Justice and the Institute on Taxation and Economic Policy, 1988), p. 43.

Lines 20 through 22

These lines total state, federal and industry share of the profits from North Slope production (lines 17 through 19) and related pipeline activities (lines 6 through 11). Because it is anticipated that by 1996 all ANS will be marketed on the West Coast, in charting trends for future production, the reader may be most interested in West Coast profit at Line 22.

Line 23

Line 23 is the average North Slope per-barrel profit. This figure is found by multiplying the Gulf and West Coast profits at line 22 by the percentage of Gulf and West Coast barrels at line 3(b).

As we turn to the tables, this caveat is in order: As indicated above, oil pricing is complicated and the companies are, as a rule, reluctant to share data on their North Slope operations. Therefore, the following tables represent approximations of North Slope profitability. The numbers used here are believed to be the most accurate numbers available to the public. Where precise data are not available and assumptions are necessary, the conventions employed reflect the best information available. These assumptions are identified above. To check the validity of the estimates generated by this model, this model was run for 1987 and the results were compared to those reported by Deakin in his 1989 accountancy study for the Department of Revenue. The results generated by this model track quite closely with those of Deakin.⁶⁰

⁶⁰ Because various elements of the oil price regime — most notably the TAPS tariff and the federal tax structure — have changed significantly since the 1977-87 period that Deakin covered, a comparison of current per-barrel profitability with Deakin's aggregate results would not be meaningful. To compare the results of these two approaches, the model developed for this report was run for 1987, the last year in the Deakin study and the first year after the federal Tax Reform Act of 1986. A comparison of the results is shown in the following table. The per-barrel profitability approach developed for this report produced a division of the economic rent for 1987 nearly identical to that reported by Deakin. This congruence indicates that the per-barrel profitability model produces a reasonable representation of North Slope economic rents.

	/ - - - - Deakin Study, 1987 - - - - /			/ - - Per-Barrel Profit Model, 1987 - - /		
	Deakin Totals * (\$mm)	% of Total Economic Rent	Implied per-bbl. share *	Implied Total (\$mm)	% of Total Economic Rent	Per-barrel Share
State	\$2,263	31.73 %	\$3.16	\$2,520	30.73 %	\$3.52
Federal	\$1,653	23.18 %	\$2.31	\$1,998	24.30 %	\$2.79
Industry	\$3,215	45.08 %	\$4.59	\$3,687	44.97 %	\$5.15

* Revenue and per-barrel profit figures from the two analyses do not match due to reliance on different data sources. A brief explanation of the major differences follows: