

HB

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STATE OF ALASKA THE LEGISLATURE

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Mary Van Nimwegen

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PETROLEUM INTELLIGENCE WEEKLY

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Short-Haul Sales By Saudis Key To Overseas Stockpile

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

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

Alaskan Oil Profits Staying Buoyant Amid Volatile Prices

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

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

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

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

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

	Sales To US Gulf Coast						Sales To US West Coast					
	1988	1987		1986		1985	1988	1987		1986		1985
Delivered Price	Current	2nd H	1st H	2nd H	1st H	Year	Current	2nd H	1st H	2nd H	1st H	Year
Sohio Price	\$15.50	\$18.45	\$17.00	\$12.00	\$16.80	\$27.00	\$14.50	\$17.45	\$16.00	\$11.00	\$15.80	\$25.00
Average Price(a)	15.25	16.82	16.29	12.31	15.72	26.91	14.25	15.48	15.56	10.75	14.54	24.23
Less:												
Shipping Cost	3.35	3.21	3.19	3.38	3.72	4.21	0.99	0.96	0.94	0.94	1.14	1.29
Value: f.o.b.	11.90	13.61	13.80	8.93	12.00	22.70	13.26	14.52	14.62	9.81	13.40	22.94
Less:												
Pipeline Loss	0.05	0.10	0.05	0.05	0.05	0.10	0.05	0.10	0.05	0.05	0.05	0.10
Pipeline Tariff	3.20	3.95	3.95	4.50	4.50	6.00	3.20	3.95	3.95	4.50	4.50	6.00
Wellhead Price(b)	8.65	9.56	9.80	4.38	7.45	16.60	10.01	10.47	10.62	5.26	8.85	16.84
Less:												
Royalty(c)	1.00	1.11	1.14	0.47	0.85	1.99	1.17	1.23	1.24	0.58	1.02	2.02
Severance(d)	0.91	1.00	1.30	0.59	0.99	2.19	1.05	1.09	1.40	0.70	1.17	2.22
Property Tax	0.15	0.15	0.15	0.18	0.18	0.21	0.15	0.15	0.15	0.18	0.18	0.21
Producing Cost	0.85	0.85	0.85	0.75	0.75	0.90	0.85	0.85	0.85	0.75	0.75	0.90
Depreciation(e)	2.25	2.25	2.25	2.17	2.17	1.53	2.25	2.25	2.25	2.17	2.17	1.53
Pre-Tax Profit	3.49	4.20	4.11	0.23	2.51	9.78	4.54	4.90	4.72	0.88	3.56	9.96
Less:												
State Income Tax(f)	0.10	0.13	0.12	0.01	0.08	0.29	0.14	0.15	0.14	0.03	0.11	0.30
US Windfall Tax(g)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
US Income Tax(h)	1.19	1.43	1.40	0.11	1.16	4.50	1.54	1.67	1.61	0.41	1.64	4.58
Oil Profit	2.29	2.64	2.59	0.12	1.28	4.99	2.86	3.09	2.98	0.45	1.81	5.08
Pipeline Profit	0.43	0.53	0.53	0.64	0.64	2.18	0.43	0.53	0.53	0.64	0.64	2.18
Overall Profit	2.63	3.17	3.12	0.76	1.92	7.17	3.29	3.62	3.51	1.09	2.45	7.26

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

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

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

US Rebuff Doesn't End London's Plans For Oil Futures Role

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

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

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

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

Africans In Opec Find Alternatives To Direct Discounting

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

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

1 minutes. I will give a two-minute warning when thirteen
2 minutes have elapsed.

3 The first party to give their opening statements will
4 be the State of Alaska. Mr. Maynard?

5 MR. MAYNARD: Thank you.

6 OPENING STATEMENT ON BEHALF OF THE STATE OF ALASKA

7 BY MR. MAYNARD:

8 Commissioner Agi, Commissioner Knowles, Commissioner
9 Guess, Commissioner Whiteaker, and Judge Wilson. My name is
10 Robert Maynard. I'm an Assistant Attorney General with the
11 State of Alaska. And again with me are, Mr. Robert Loeffler
12 and Mr. Ed Tome.

13 The State in this opening statement wishes to make
14 primarily two points and that is, first, that the State is
15 relatively indifferent to the outcome of the intrastate
16 tariff dispute. Secondly, that we believe the APUC Staff's
17 and other's attack on the settlement as being devoid of any
18 public policy or any public interest, we believe that that
19 attack is misplaced, is inappropriate and is overstated.

20 We believe the settlement should be approved as a
21 fair and reasonable resolution of what might otherwise be
22 an interminable dispute. In fact, almost all of the actual
23 economic interests involved in this tariff dispute approve
24 of this settlement, including over 99 percent of the ship-
25 pers over the intrastate line. We believe that whatever



*Saw,
Per Agi's request*

LINDA STEWART
UTILITIES ENGINEER

1 resolution this Commission gives to this settlement pro-
2 ceeding, whether it grants the settlement or whether it
3 decides a continued litigation is appropriate, we believe
4 that this settlement should at least be accurately por-
5 trayed, which we do not believe it has been in this pro-
6 ceeding to date.

7 With regard to the interest of the State of Alaska at
8 this point in the in-state tariff dispute, the APUC Staff
9 basically says that the State will lose \$5 billion by this
10 settlement. Now, that is a number based on the interstate
11 numbers on this pipeline as a whole. We believe that is
12 high by at least a factor of two. But to use it as a basis
13 for complaining against the intrastate tariff, we believe is
14 misleading. The State's interest is not nearly that amount.
15 In fact, we are probably indifferent. The reason for that is
16 two points.

17 First, there is a crediting provision with regard to
18 the settlement that was actually taken from the stipulation
19 entered into by all parties in the interstate tariff dis-
20 pute, including the APUC Staff. That crediting provision
21 would provide that intrastate revenues would be credited
22 against the interstate revenue requirement. Thus, the more
23 that is collected on the intrastate tariff the less that
24 needs to be collected on the interstate tariff.

25 The second reason, which I will explain in some detail

1 to come, is that the State's revenues are almost all based
2 on the interstate tariff, on out-of-state shipments. The
3 State gets its revenues off the pipeline in three forms;
4 one, is by the effect on the severance tax; another is the
5 effect on the royalty; the third is the effect on the
6 corporate income tax.

7 Now, the severance tax and the royalty when we leave
8 it with the producers, when we take our royalty in what is
9 termed "end value" is based on what the companies report
10 to the State for their dispositions of oil. Almost all of
11 those dispositions are out-of-state dispositions that
12 depend on the interstate tariff.

13 It is true the State sells a large proportion of its
14 oil in-state to in-state refiners, and that is shipped over
15 the intrastate tariff, which is the subject of this Commis-
16 sion's hearings. But the price that the State receives on
17 its in-state sales of contracts to Chevron, Tesoro and
18 MAPCO is based on the companies' reported prices. The
19 term is that we get what we would have gotten if we had
20 left that oil end-value with the producers. And that price
21 is determined by the companies' reported prices which is in
22 turn based on the in-state tariff -- interstate tariff.
23 Excuse me.

24 The third factor is the corporate income tax, but
25 because of the crediting provision, it doesn't matter what

1 the in-state tariff is, the overall revenues will be the
2 same. So the corporate income tax is not affected.

3 Thus, at best, the State is indifferent as an economic
4 basis on its financial interest on the intrastate tariff.

5 The question arises of why are we in the case. Well,
6 initially we were in the case for two reasons. The first
7 reason was that at that time, we wanted to have the same
8 position presented before the then APC and the FERC. We
9 believed that inconsistent result between the APC's ruling
10 could hurt our interstate case before then the ICC to become
11 the FERC.

12 Second, at that time it was believed that the Attorney
13 General's Office could assist in a great degree with at that
14 time what perceived to be greater resources in prosecuting
15 the in-state case. At the present time neither of those
16 two particular points apply. FERC has ruled on the inter-
17 state tariff, and has also had a general methodology to be
18 applied to other pipeline tariffs.

19 Second is a budget crisis. A request for a certain
20 amount of money has been basically slashed 25 percent in
21 the internal reviews, and I don't believe there's much
22 likelihood of getting a whole bunch back during the legis-
23 lative process. Because of that, whatever the Commission's
24 resolution of this dispute, the State will not be presenting
25 an independent viewpoint before the Commission on this

1 pipeline case or probably other pipeline cases. The State's
2 economic interest is not there and we believe the APUC
3 Staff has sufficient resources to prosecute the in-state
4 case if, in fact, this Commission decides to continue on
5 with the case or other pipeline cases.

6 Why are we here necessarily with such a great pre-
7 sence, with a witness and making statements? We may not
8 have been here in such a great presence if the settlement
9 had been accurately portrayed and if the presentations
10 against the settlement had been based on basically intra-
11 state concerns. But neither of those two points have been
12 the case. The attacks have inaccurately portrayed the
13 settlement and have taken basically an attack against the
14 underlying policy as being totally devoid of any public
15 interest in this settlement. Because of that we would
16 at least like to have some record that there might be
17 some reasons why this settlement is in the State's interest
18 and to rebut some of the charges that have been made.

19 Mr. Horst will present in some detail in his testi-
20 mony the inaccurate portrayals of the settlement process
21 itself or the settlement itself. But overall, the APUC in
22 its papers has basically attacked the settlement as losing
23 the State money, \$5 billion and as having no public interest.
24 We believe that is overstated.

25 Now, we want to make it clear from the outset that

1 we believed and still do believe that a litigated conclu-
2 sion to this case should give the State substantially more
3 money and a substantially better position than it's getting
4 out of the settlement. The numbers we gave publicly a
5 couple of years ago during the legislative debates was
6 about \$2½ billion was what we believed a reasonable liti-
7 gated conclusion to this settlement would give the State.
8 But there are two problems with that.

9 First, there was the risk that we wouldn't get that
10 2½ billion, that we wouldn't even get what we would get by
11 this settlement. There were potential outcomes that would
12 give the State substantially worse than what we got by the
13 settlement, particularly considering the fact that there
14 have been rulings by the FERC that would have given the
15 State much worse.

16 Secondly, there was a severe problem of time. After
17 eight years of litigation, even the ALJ in the case was
18 saying that it would be ten years before a litigated con-
19 clusion would come to an end. That would only start the
20 State's problem. We would then have to collect the money --
21 not from the pipeline shippers, but from the companies
22 paying severance tax royalty and would have to chase down
23 royalty in-kind purchasers, such as ALPETCO, who is now in
24 bankruptcy. There were concerns there.

25 Now, no one in the long and sometimes acrimonious debate

1 argued about whether or not the TAPS settlement has been in
2 the public interest. To my knowledge no one has ever stated
3 that this settlement was a bad settlement in terms of the
4 fact the State could have voluntarily gotten more from the
5 companies. The debate has always been we should have con-
6 tinued to litigate; that the settlement may have been the
7 best voluntary agreement you could have gotten out of the
8 companies but you should have litigated this thing to its
9 conclusion because you're going to win a lot more. And yes,
10 if we had litigated we might have won more, we believe we
11 should have won more, we believe we had a good chance of
12 winning something more. But by the settlement we will at
13 least gain three advantages; one, we gained substantial
14 immediate relief. We got lower tariffs now instead of
15 waiting ten years down the road. We gained certainty
16 through the end of the century and avoided the possibility
17 of endless yearly rate cases with stale records being
18 constantly raised to the challenge to any long-term solution
19 to the rate cases. And the State did achieve some long-term
20 developmental interests by load tariffs through the end of
21 the century, in fact, to the first decade of the next
22 century which at various times throughout the state has
23 been bantered as one of our main policy goals.

24 Now, we could discuss those policy goals at length,
25 I would only have to give one example. And in fact is

1 not an example that was one of the driving forces of this
2 settlement when we entered into it two years ago, but it
3 does show why settlement sometimes and the certainty afforded
4 by settlement can have good consequences.

5 The settlement already through fiscal year 1988 will
6 bring approximately -- that means July 30th, 1988 -- will
7 being approximately -- July 1, 1988, excuse me -- will bring
8 approximately \$800 million in benefits to the State. That
9 comes to approximately from \$230 million in refunds and
10 between \$300 and \$350 million of annual tariff revenues
11 over what the tariffs would have been if we had not entered
12 into the settlement because, remember, without the settle-
13 ment, tariffs would have stayed at the \$6.01 rate until
14 the end of litigation.

15 Now, the recent revenue projections, the January
16 revenue projections just released by the Department of
17 Revenue give the following unrestricted revenues coming
18 into the State with the TAPS settlement for the next three
19 years: fiscal year '87, \$1.334 billion; fiscal year 88,
20 \$1.325 billion; fiscal '89, \$1.374 billion. Now, the
21 money coming in from the TAPS settlement for FY 87 and FY 88
22 again is \$800 million. Total unrestricted revenues are
23 \$2.6 billion. The settlement is bringing in almost one-
24 third of the unrestricted revenues the State is receiving.

25 For fiscal year '89 the settlement will almost bring

1 in a quarter of the unrestricted revenues, about 300 or
2 350 million of 1.4 billion; less than a quarter but almost
3 a quarter.

4 The State is already facing a budget deficit of
5 \$900 million going into this fiscal year. It will be tough
6 to imagine when another \$800 million load would be on that.

7 Now, yes, we possibly could have gotten \$2½ billion
8 more ten years from now with interest, but to tell someone,
9 to tell a student asking for a student loan they can get
10 more money ten years from now but can't go to school this
11 year; to tell an AFDC recipient they can get more money
12 ten years from now but not enough money this year; to tell
13 longevity bonus recipients, a senior citizen 70 years old,
14 that ten years from now he might get a lot more money; for
15 building roads, for building infrastructures, sewer, water,
16 for all the things the State does -- economists, accountants,
17 lawyers can put a time value on money. It's very difficult
18 to put a time value on services and difficult to put a
19 time value on the provision of the basic necessities of
20 life to the citizens of the state. When you're giving --
21 the State's a hungry man. The question is, do you want a
22 square meal now or a feast ten years later? I think most
23 people when you're hungry would want a square meal now.

24 This is not to say that the opposition to this settle-
25 ment is illegitimate. In fact, there are good reasons why

1 you might say that settlement is not appropriate, you
2 shouldn't be settling these types of cases. There's
3 disagreements about the risk that we face going on. There's
4 disagreements about whether we need money now or later,
5 whether we should do different things. There are legitimate
6 reasons to argue in the public policy mode that maybe settle-
7 ment is not appropriate. And in fact you will be hearing,
8 no doubt, and from Representative Davis for one, legitimate
9 reasons and concerns as to whether or not settlement on the
10 interstate on the whole basis is an appropriate public
11 policy. The previous governor, Governor Sheffield, believed
12 that settlement was appropriate. There are legislators who
13 do believe that settlements are appropriate, other people
14 do not.

15 We are not trying to say that the issue is clear one
16 way or the other. But when the APUC Staff says that there
17 is no public interest in this settlement, we believe they
18 are incorrect and overstating the matter. And when the
19 APUC Staff and other people are trying to force the inter-
20 state settlement policy debate into this intrastate pro-
21 ceeding, we believe that is inappropriate because those
22 policies were on the interstate side.

23 JUDGE WILSON: You have two more minutes,
24 Mr. Maynard.

25 MR. MAYNARD: Thank you, Judge Wilson. The issue here

1 is whether or not the APUC will find the settlement to be a
2 fair and reasonable resolution of the intrastate dispute.
3 All the State is really asking for in this particular pro-
4 ceeding, whatever the outcome of this resolution, is that
5 you give a balanced recognition of both the faults and the
6 merits of the settlement as well as this settlement or any
7 other negotiated conclusion.

8 We believe the central question is whether you have
9 to determine whether this settlement must meet the just and
10 reasonable standard or the fair and reasonable standard.
11 If you do not believe the fair and reasonable standard is
12 appropriate, it is our belief you do not need to reach the
13 question of whether or not this settlement is just and
14 reasonable, because we do not believe there is a record
15 before this Commission to make that finding. We would ask
16 if you do not believe the settlement can be resolved on
17 the fair and reasonable standard that you simply dismiss it
18 and go on with litigation, and the State will live with
19 whatever outcome comes on. We think it is a shame it would
20 happen, because with the intrastate proceeding it seems to
21 us that all the people who have economic interest are
22 willing to live with the settlement, and our particular
23 resolution would allow those who oppose it to continue to
24 oppose it. But that is the Commission's choice and we just
25 simply ask for fair treatment of this settlement proposal.

1 Thank you very much.

2 JUDGE WILSON: Thank you, Mr. Maynard. We will now
3 have the opening statement of the TAPS Carriers. Mr. Brose?

4 OPENING STATEMENT ON BEHALF OF THE TAPS CARRIERS

5 BY MR. BROSE:

6 Thank you, Commissioners, Judge Wilson. My name is
7 Stephen Brose and I'm appearing today on behalf of the TAPS
8 Carriers. I certainly intend to keep my opening remarks
9 well within the allotted time, and I certainly don't intend
10 to retrace in any detail the material found in our briefs
11 or in the prepared testimony of our witness Mr. Richard
12 Hildahl.

13 What I would like to do is to take this opportunity
14 to try to put this case and your role in it into its proper
15 context, because there has been far too much testimony and
16 briefing on both sides that may tend to direct the Commis-
17 sion's attention away from the ultimate issues and either
18 on to peripheral matters or issues that really aren't
19 before you at all.

20 I'd like to start by emphasizing what the Commission
21 is not being asked to do in this proceeding. First, as
22 both Mr. Maynard and the reply briefs have made clear, the
23 question of the lawfulness or even the desirability of the
24 TAPS Interstate Settlement which governs more than 96 per-
25 cent of total TAPS shipments is not at issue here.

1 That settlement, as you undoubtedly are aware, is solely
2 within the province of the FERC and it has been approved by
3 that Commission without qualification and is currently
4 pending affirmance in the United States Court of Appeals.

5 All that's at issue here is whether the TAPS settle-
6 ment should be approved as it relates to the less than
7 4 percent of TAPS movements that travel intrastate.

8 And so let's just be sure that we don't get too
9 caught up in the rhetoric about the supposed overall
10 impact of the TAPS settlement, because even if the calcu-
11 lations that appear in the APUC Staff's presentation were
12 correct, and we believe we have shown that the Staff's
13 assessment isn't even remotely in the ballpark, they're
14 simply of no relevance whatsoever to this proceeding.

15 Second, and the testimony and the issue statements
16 appear to have obscured this as well, you are not being
17 asked to approve for all time the rates produced by the
18 TAPS settlement methodology, what we call the TSM. The
19 settlement is an agreement between the TAPS Carriers and
20 the State of Alaska and it's effect is to establish a
21 formula that those parties agree will govern the setting of
22 a ceiling on TAPS intrastate rates. In other words, the
23 Carriers have simply agreed that they will not file rates
24 above those produced by the TSM formula, and the State has
25 agreed that it will not challenge rates that are filed at or

1 below those ceilings. Nothing in the agreement deprives
2 the Commission of its jurisdiction to look in the future
3 at whether the TSM rates are unreasonably high, nor does
4 anything prevent any non-signer, Petro Star or Arctic
5 Energy or whomever, from challenging those rates at any
6 point in the future. In fact, the agreement requires that
7 the Carriers file with the Commission every year revised
8 tariff sheets and to provide the Commission with data suf-
9 ficient to analyze the filings.

10 What your approval will establish is that the settle-
11 ment governs the intrastate rates that have been charged
12 to date; that any refunds owed under the agreement will,
13 once paid, extinguish the Carrier's refund liability and
14 that the pending TAPS intrastate rate dockets will be
15 terminated.

16 The other recently-opened proceedings, the dockets
17 involving the margin terminal costs and the TAPS connection
18 policy, will go forward unaffected by the result reached
19 in this case.

20 Now third, and this is crucial, you are not being
21 asked to decide whether the rates produced by TSM are just
22 and reasonable, nor are you being asked, as some of the
23 issue states seem to suggest, to figure out whether you can
24 apply some lesser standard if you conclude that the rates
25 are not just and reasonable. The question of whether the

1 TAPS rates are or are not just and reasonable in a rigid and
2 legalistic sense is precisely what the settlement proceeding
3 is designed to avoid. Because in order to determine whether
4 the rates are just and reasonable in the sense that Petro
5 Star and the Staff would use that term, you and we would
6 have to go through the full range of issues, the full range
7 of procedures that would be required if this proceeding
8 were to be fully litigated. In other words if, as the
9 settlement opponents suggest, the settlement can be approved
10 only if you find the TSM rates to be just and reasonable in
11 a technical sense, then there will be no cost savings, no
12 reduction in litigation burdens, no room to fashion any
13 kind of compromise outcome in trying to settle the case. The
14 effort involved in settling will be precisely the same as
15 the effort involved in litigation. And the hardening and
16 polarizing of positions will inevitably defeat the settle-
17 ment process.

18 We believe that your discretion -- and by that we
19 mean your power to use your good judgement, simply doesn't
20 compel you in that direction.

21 The real problem with the just and reasonable stan-
22 dard as Petro Star and the Commission Staff have used it is
23 that when you get to the bottom of their definition, all
24 they're saying is that just and reasonable means the result
25 that would be reached in litigation. And if that's right,

1 then the Commission simply has to understand that a rate
2 case before it can never be settled. Because in order to
3 approve a settlement it will have to decide the case and
4 it will have to do so on the basis of a complete record.
5 And we submit that the Commission has a great deal more
6 authority over its docket than that, and that that's what
7 the Alaska Supreme Court meant when it said in the Jaeger
8 case that the Commission must be free to determine whether
9 future proceedings are in the public interest.

10 If just and reasonable in the sense of the result of
11 litigation, the litigation outcome, isn't the test for
12 approving the settlement then what is? Settlement opponents
13 seem to be stumped by that question. And frankly, in view
14 of the Supreme Court's language that I just quoted, that
15 stumps us. We just can't understand the idea that this
16 Commission doesn't have the authority to agree to the
17 voluntary termination of a dispute on grounds that it finds
18 to be fair and reasonable and in the public interest. And
19 there really shouldn't be any mistake about it, this agree-
20 ment, this settlement that we have offered to you for your
21 approval is fair and reasonable and in the public interest.
22 It will end a litigation that is becoming legendary in its
23 dimensions and in its longevity. It's nine years old
24 already. There is no end in sight, and that's true even as
25 to rates that were charged in 1977. And it's no small matter

1 that in light of the interstate settlement, the entire
2 litigation expense from this point forward will fall solely
3 on the intrastate shippers.

4 Now apart from ending the rate case, the settlement
5 will result in the immediate payment of tens of millions
6 of dollars in refunds to independent parties who have made
7 it clear that the alternative that's been proposed to them
8 of awaiting the end of the litigation process to see if
9 they can do better than that is just flat-out unacceptable
10 to them.

11 The settlement will also see the immediate filing of
12 permanent and significant rate reductions. And finally,
13 it will bring a high degree of certainty to everyone con-
14 cerned; to the Carriers, who will finally be able to remove
15 the ten-year cloud of refunds from their books, and it will
16 be able to make educated projections for the first time
17 about their future revenues. And it will also provide
18 certainty to current and prospective shippers who for the
19 first time will know with certainty the most they will have
20 to pay for TAPS transportation into the 21st Century, and
21 that's a knowledge that will be impossible for them to
22 gain if the settlement is rejected.

23 Let's go back to the basics of what we have here.
24 It's an agreement between the parties -- and by that I mean
25 the State and the eight TAPS Carriers that have carried the

1 litigation burden of this case for a decade, coming to a
2 meeting of the minds that can end their dispute. The only
3 other parties that had expressed any previous interest in
4 the case, MAPCO and Tesoro, agree that this is a fair and
5 an economically attractive outcome and they actively sup-
6 port the settlement. This is no sweetheart deal. Both
7 sides came to the bargaining table with significant bargain-
8 ing power and with perspectives that, to say the least, were
9 poles apart. And all these parties are asking is that they
10 be allowed to stop fighting with each other on terms that,
11 for their own entirely independent reasons, they believe
12 to be acceptable even if not perfect.

13 Are those terms the one that the Commission would
14 Order after full litigation? Probably not. Does that matter?
15 Absolutely not. The resolution of complex cases requires
16 imaginative solutions, and that's what this is. The trade-
17 offs of the various concerns that are reflected in the
18 settlement agreement, the high front-end depreciation rates,
19 the low real rates of returns and so on, is something that
20 only the interested parties can accomplish in anything that
21 approaches a satisfactory way. And in this regard we
22 would commend to the Commission's attention a thoughtful
23 article in the August 21, 1986 issue of Public Utilities
24 Fortnightly entitled "Negotiated Settlements in Utility
25 Regulation, which was authored by the Chairman of the

1 New Mexico Public Service Commission, named Marilyn O'Leary,
2 in which she explored the very significant public interest
3 advantages in the settlement of rate cases.

4 Now in contrast to all this, what is it that the
5 settlement opponents are telling you that they want? As
6 best we can tell what they're really after when you get to
7 the bottom of it is to force the TAPS Carriers and the State
8 to keep on battling with each other even though we found
9 common ground that we can live with, just so that the non-
10 settling parties can have someone else to fight their bat-
11 tles for them. The settlement opponents have no right to
12 make us do that. And there is no conceivable public interest
13 rationale for forcing us to do so.

14 This agreement will cause no undue or no unfair
15 economic harm to any party and, in fact, will have no undue
16 impact at all on any non-settling party. It is simply
17 what our briefs and the testimony of Mr. Hildahl show it
18 to be; fair and reasonable and in the public interest as
19 a resolution of the dispute between the settling parties.
20 And we submit that you have the authority to approve the
21 settlement on those terms and that doing so would be a
22 proper and judicious exercise of your discretion.

23 JUDGE WILSON: Thank you, Mr. Brose.

24 We will now have the opening statement from MAPCO
25 Petroleum.

1 OPENING STATEMENT ON BEHALF OF MAPCO PETROLEUM, INC.

2 BY MR. JONES:

3 Commissioner Agi, Commissioner Knowles, Commissioner
4 Guess, Commissioner Whiteaker, and Judge Wilson. I'm the
5 Secretary and General Counsel for MAPCO Petroleum and
6 welcome this opportunity to appear this day to express our
7 view on this settlement as a shipper.

8 MAPCO Petroleum, an Alaska corporation, and an in-
9 state refiner, has been a party to these proceedings from
10 almost their inception in 1977. In fact, MAPCO Petroleum
11 is the only non-affiliated shipper who has participated
12 in the proceedings before the Interstate Commerce Commission,
13 the Federal Energy Regulatory Commission, the Alaska Public
14 Utilities Commission and its predecessor the Alaska Pipeline
15 Commission, that had led up to this hearing on the offer
16 of settlement.

17 As one of the largest non-affiliated shippers on
18 TAPS and as one of the companies with a significant and
19 real financial interest in the outcome of these proceedings,
20 we urge the Commission to approve the offer of settlement
21 submitted by the State of Alaska and on behalf of the eight
22 TAPS Carriers.

23 MAPCO Petroleum believes that the settlement is fair
24 and equitable and that it warrants the Commission's appro-
25 val for five primary and compelling reasons.

1 First, approval of this settlement will trigger pay-
2 ment by the TAPS Carriers of tens of millions of dollars
3 in refunds to the non-affiliated intrastate shippers.
4 Assuming the refunds are paid July 1, 1987, MAPCO Petroleum
5 now anticipates that it will receive a refund, including
6 interest, of approximately \$10 million. These refunds
7 cover shipments starting January 1, 1982 and running through
8 mid 1986, when the stipulation establishing temporary lower
9 intrastate rates went into effect.

10 Opponents of the settlement complain about the lack
11 of refunds for shipments made prior to 1982. But who are the
12 opponents? Only one, Petro Star, is presently a shipper,
13 but it did not commence shipments until late 1985. In
14 other words, none of the opponents of the settlement were
15 shippers prior to 1982. More importantly, the two shippers
16 who shipped most, if not all of the intrastate barrels
17 prior to 1982 and who would benefit from refunds for ship-
18 ments prior to 1982, both support the proposed settlement.

19 Failure to approve the settlement would result in an
20 undeterminable but presumably significant delay in the
21 receipt of any refunds by us and other intrastate shippers.
22 While one might think this is covered by interest on refunds,
23 such is not the case. Failure to receive the money now
24 results in what I call "lost opportunity costs". If
25 refunds are paid this year, that money is available for

1 investment in projects that meet the recipient's internal
2 rate of return for investments. Presumably such investment
3 will return more than simply investing the money in an
4 account and drawing interest. If this were not the case,
5 companies would simply place all their capital in interest-
6 bearing accounts and economic development would come to a
7 virtual standstill.

8 Second, approval of the settlement will result in
9 not only lower but also final intrastate tariff rates, not
10 only for the full-length intrastate shipments to Valdez,
11 but also for intermediate intrastate shipments to the GVEA
12 connection. Even though the TAPS Quality Bank Settlement
13 approved by this Commission in 1984 established a method-
14 ology for determining the intermediate intrastate rates
15 to the Golden Valley connection, no final rates can be
16 determined and, hence, no refunds calculated and paid until
17 the Commission approves a methodology and final full-
18 length intrastate rates.

19 Thus, not only will your approval of this settlement
20 establish full-length intrastate rates that as of January
21 1, 1987 would be about \$2.20 per barrel lower than they
22 otherwise would be, such approval will also result in
23 intermediate intrastate rates that are about \$1.30 per
24 barrel lower than they would be absent the settlement.

25 These significantly lower rates and the projected

1 lower rates in the future are made possible in part by
2 frontloading the tariffs in the initial years, particularly
3 the rates in effect prior to 1982.

4 The opponents object to this technique. Yet, again,
5 it is necessary for the Commission to focus on who is
6 impacted by the frontloading of the tariffs. The opponents
7 are not because they did not ship any barrels during this
8 period of time. The only intrastate shippers impacted by
9 the frontloading are the shippers who support the settlement.
10 If the settlement is not approved, then the stipulation
11 approved by you on May 1986 likely would cease. As you
12 recall, this stipulation established lower temporary intra-
13 state tariff rates based on the lower interstate tariff
14 rates resulting from the FERC's approval of the Interstate
15 Settlement Agreement, which agreement was virtually identi-
16 cal to the settlement agreement now before you.

17 If the stipulation ceases, the likely result would
18 be a weighted average increase in the full-length intra-
19 state tariffs of about \$2.20 per barrel, and a weighted
20 average increase in the intermediate intrastate rates of
21 about \$1.30 per barrel. For us this could result in an
22 increased crude oil cost of up to \$34,000.00 per day or
23 around \$1 million per month.

24 Third, by establishing a methodology that establishes
25 maximum rates that can be charged, approval of the settlement

1 would finally provide a degree of certainty as to future
2 rates. Such certainty is essential for the future planning
3 of projects and economic planning.

4 Fourth, approval of the settlement will bring an end
5 to almost ten years of expensive litigation. Not to
6 approve the settlement likely promises many more years of
7 costly litigation.

8 As a company and the only non-affiliated shipper who
9 has participated in the litigation for almost its entire
10 duration, the decision as to which alternative to choose
11 is easy. Hence, we do not agree or say that we do not care
12 what happens if you don't approve it. We certainly do
13 care, based on our ten years of experience.

14 Fifth, approval of the proposed settlement will
15 result in the full-length intrastate rates being the same
16 as the interstate rates. Since the same crude oil is being
17 transported the same distance through the same facilities
18 to the same destination, there is no basis for the intra-
19 state and interstate from Pump Station No. 1 to Valdez
20 to be different. As an interstate shipper to Valdez, we
21 would be very concerned about there being lower intrastate
22 tariffs for this same movement. Any such difference could
23 have an adverse impact on us and any other refiner similarly
24 situated when compared to other in-state refiners with
25 whom the interior refineries compete, because the cost

1 component represented by shipping barrels to Valdez would
2 be different simply due to what tariff the barrels were
3 shipped on, even though identical crude oil was shipped
4 the same distance through the same pipeline.

5 Finally, in reviewing the pleadings and testimony in
6 this proceeding, I would like to again remind you and ask
7 you to note as the Commission that it is important for
8 the Commission to evaluate and give strong consideration
9 to the fact that the largest non-affiliated in-state ship-
10 pers, those parties with by far the greatest economic
11 interest in the resolution of the rate case, support the
12 settlement. The parties opposing the settlement do not
13 have the same economic interest. In fact only one, as I
14 noted, is presently a shipper. The shipper Petro Star only
15 began shipments in late 1985. Arctic Energy is, at best,
16 a prospective shipper, since it has not yet constructed a
17 refinery. The third opposing party, the APUC Staff, also
18 has no economic interest in the outcome. Any economic
19 interest of the State of Alaska presumably is represented
20 by the State itself, which is not only a party but also a
21 signatory to the settlement agreement and offer of settle-
22 ment now before the Commission. Much of the Staff's opposi-
23 tion appears to consist of adopting the issues raised by
24 the State at the initial stages of the rate proceedings;
25 issues which the State now has settled with the TAPS Carriers.

1 Furthermore, approval of the settlement does not pre-
2 clude these parties from continuing to litigate the issues
3 they deem important. They are free to do so, but they
4 should not be free to do so at the expense of us and
5 of the other shippers who support the settlement.

6 MAPCO Petroleum should not be deprived of the benefits
7 of the settlement. In closing I would like to ask and point
8 to what happens to MAPCO Petroleum if the settlement is not
9 approved? Not only would we not receive in the near future
10 approximately \$10 million in refunds, but as I noted, the
11 intermediate intrastate tariff could increase by about
12 \$1.30 per barrel or at a cost to us at about or up to
13 \$34,000.00 per day. And even more so and ironically, since
14 the stipulation that was entered into in May of 1986 pro-
15 vides that in the event, in effect, the intrastate settle-
16 ment is not approved, the Carriers have the right to retro-
17 actively revert to the tariffs that would have been in
18 effect but for the temporary tariffs established by the
19 stipulation. The net effect of this is that we could find
20 ourselves instead of receiving \$10 million this year having
21 to pay up t \$10 million to the TAPS Carriers plus to
22 continue paying the increased costs in the future and also
23 the cost of litigation. Thank you.

24 JUDGE WILSON: Thank you, Mr. Jones.

25 We will have the opening statement from Commission
Staff, Mr. Bird.

1 OPENING STATEMENT ON BEHALF OF THE COMMISSION STAFF

2 BY MR. BIRD:

3 Commissioners, Judge Wilson. In order to respond to
4 Mr. Jones' last question, Petro Star and the Staff have
5 worked out a proposed schedule which I intend to address at
6 the close of my comments. And in order to address that
7 schedule, Petro Star has graciously granted me one or two
8 extra minutes for my allotted fifteen minutes, and with
9 Your Honor's approval, I will work as fast as I can to make
10 that schedule.

11 JUDGE WILSON: Proceed.

12 MR. BIRD: It is clear from the opening statements and
13 the briefs that all the parties to this proceeding agree on
14 two critical matters. First, that the rates produced by
15 TSM cannot be shown to be just and reasonable. And, there-
16 fore, the Commission should not approve the settlement on
17 the grounds that TSM rates are just and reasonable.

18 Second, that whether the APUC accepts or rejects
19 TSM, it will in either case have no effect whatsoever on
20 the revenue or budgetary considerations of the State of
21 Alaska.

22 The Staff takes great comfort from each of these
23 points, and in particular the latter. For we believe that
24 as a result of the '83 stipulation concerning revenues,
25 the FERC settlement and the provisions of 4206.400 and

1 Section 400 (b), each of the policy considerations are
2 benefits sought from the settlement by the settling parties
3 either has already been effectuated or can otherwise be
4 implemented in the near future.

5 Moreover, as the combined result of these circum-
6 stances, the Commission can proceed to implement the just
7 and reasonable standard established by Sections 370 and
8 410 (a) without concern for application of some lesser
9 untried standard as recommended by the State and Carriers.

10 Close inspection of the fallacy of the settling
11 parties' arguments demonstrates the accuracy of these con-
12 clusions. First, the Carriers argue that approval of the
13 settlement is necessary to put an end to litigation and to
14 provide them with the revenues for which they have bargained.
15 In fact, litigation will continue on the very same issues
16 and with the Carriers even if the settlement is disapproved.

17 Moreover, because of the '83 stipulation and the
18 FERC settlement, the Carriers' revenues are firmly estab-
19 lished now regardless of what this Commission does. The
20 State argues that the settlement is necessary to serve the
21 public's interest in ending litigation, allowing for
22 certainty in its planning, and in providing the State with
23 revenues now as opposed to the end of these proceedings.

24 In fact, the State need not participate in further
25 litigation because it will not be affected by its outcome

1 due to the '83 stipulation and the finished and approved
2 FERC settlement. Indeed, as Mr. Maynard and Mr. Loeffler
3 have each pointed out, the State's intention to absent it-
4 self from further litigation is clear.

5 As to revenues, the State has already been paid inter-
6 state revenues it stands to earn from TSM as a result of
7 the FERC's approval of the settlement. Thus, the State has
8 already gained most of the benefit of its bargain regardless
9 of what this Commission does.

10 As to interstate refunds, the Staff believes those
11 can be ordered paid pursuant to Sections A. S. 4206.410 (b)
12 at the close of these settlement review proceedings.

13 Next, MAPCO and presumably Tesoro would argue that
14 settlement must be approved so they can receive refunds
15 now. They also will argue that they need the settlement so
16 that they can glean the benefit of some certainty in their
17 operational planning, and, finally, so that they can avoid
18 further litigation costs. In fact, the Staff believes that
19 continued litigation can be brought to a fair and expeditious
20 resolution while providing for the immediate benefits
21 sought by MAPCO and Tesoro.

22 To illustrate this point more fully, as I have noted,
23 at the close of this opening statement I will recommend a
24 schedule and procedures by which MAPCO and Tesoro can be
25 paid the refunds they expect to receive from TSM at the

1 time they expect to be paid, and by wh. MAPCO and Tesoro
2 will pay TSM rates until just and reasonable rates are set.

3 These then are practical solutions to the issues
4 raised by the Staff and settling parties. Of course, the
5 owners and the State will and have argued that these practi-
6 cal solutions are unnecessary and that the Commission should
7 avoid the fact that TSM rates are unjust and unreasonable
8 by; one, applying the lower standard of review to the
9 settlement; and, two, by instituting a FERC procedure which
10 is heretofore untried by this Commission.

11 The Staff respectfully urges the Commission to reject
12 the settlement even under the lower standard recommended
13 by the settling parties, and to avoid an ad hoc application
14 of the Rule 602 procedure to these proceedings.

15 To put the settling parties' arguments into proper
16 perspective, it is important to take note of the statutory
17 context in which these arguments are made. First, and the
18 starting point is Section 370 (a). Section 370(a) is
19 straight-forward and it's clear - (reading) All rates
20 demanded and received by a pipeline carrier or by two or
21 more pipeline carriers for service furnished or to be
22 furnished shall be just and reasonable.

23 Section 410(a) erases any doubt about the Legisla-
24 ture's intent. It requires that when the Commission after
25 an investigation hearing finds that a rate is unjust or

1 unreasonable or unduly discriminatory or prejudicial, the
2 Commission shall determine a just and reasonable rate to be
3 observed or allowed, and then shall establish it by Order.

4 In conjunction with these standards, the Commission
5 has been empowered by A. S. 4206.140 (a)(2) to investigate
6 on its own motion the rates of pipeline carriers. And
7 finally, it is noted that there exists no statutes or
8 regulations which permit deviation from these standards as
9 required by Section 370(b).

10 The Staff believes that these statutes evidence a
11 Legislative intent to institute active regulation of intra-
12 state pipeline rates; and more specifically, an intent to
13 have this Commission actively participate in the setting
14 of rates so that intrastate interest not be penalized or
15 disadvantaged by any lack of resource.

16 Now, the Carriers and the State urge two principal
17 arguments to justify approval of the settlement pursuant to
18 a standard lower than just and reasonable. Neither is
19 persuasive. Initially it is suggested that Jaeger versus
20 this Commission permits the procedure and standard recom-
21 mended by the settling parties. Jaeger carries with it
22 many lessons, none of which support the reading given to
23 the case by the Carriers and the State. The Supreme Court
24 and the Commission before it considered in Jaeger the
25 question of whether a complainant had demonstrated sufficient

1 evidence to justify prosecution of his claims that certain
2 rates were discriminatory. While the Supreme Court found
3 that the Commission had the discretionary power to refuse
4 to allow Jaeger to pursue his claims, at no time did the
5 Supreme Court suggest or say that such discretionary power
6 exists for the purpose of lowering the statutory standard
7 for consideration of whether those rates were just and
8 reasonable or discriminatory. The right to have the
9 Commission act, referred to in the Carriers' and in Jaeger,
10 is completely different from the right to have the Commission
11 apply the just and reasonable standard or any other stan-
12 dard.

13 The settling parties also argue that the Commission
14 has inherent power to establish a FERC Rule 602(g) type of
15 procedure. The Staff rejects this argument for several
16 reasons. First, the settling parties' arguments are incon-
17 sistent with the statutory scheme which I have just discus-
18 sed and should be rejected on that basis.

19 Second, the application of a lower standard by way of
20 a separation of contesting parties from uncontesting
21 parties is unnecessary in this case, in light of the fact
22 that the settling parties have already received or can
23 otherwise receive the benefits they seek from this settle-
24 ment without approval of the settlement. As I have just
25 discussed because of the stipulation and the FERC settlement,

1 the Carriers have already been assured of their revenues.
2 The State need not continue to litigate and has said it
3 will not. The Carriers will have to continue to litigate in
4 any event with Petro Star and the Staff. MAPCO and Tesoro
5 can, pursuant to Section 410(b) and 400, receive the
6 benefits of the Carriers' and the State's bargain without
7 the necessity of the Commission approving the settlement.

8 Third, even if the Commission decides that a lower
9 standard is required in order to foster or encourage settle-
10 ments, the standard recommended by the State and the owners
11 is so amorphous as to be unworkable here.

12 Fourth, even if the lower, fair and reasonable and
13 at the public interest standard were applied, it should
14 be applied so that the outcome of this and any settlement
15 not be so divergent from traditional regulatory methodology
16 as to be outside a zone of reasonableness, and, therefore
17 to be against the public interest. In this case the
18 testimony of Rudy Bertschi clearly demonstrates that TSM
19 produces such results.

20 Now, the owners and the State have leveled various
21 criticisms at the Staff, at Staff's opposition and
22 Mr. Bertschi's testimony. I would like to quickly discuss
23 some of those points in order to put the Staff's position
24 in proper perspective.

25 The Staff has been portrayed as intransigent, as

1 improperly second-guessing the States Attorneys, as
2 improperly usurping the Department of Law's functions.

3 The Commission's regulations at 3(a)(a)(c) 48.275(j)
4 anticipate the Staff's role and analyzing and opposing, if
5 necessary, filed rates when those rates are contrary to
6 4206. The Staff's opposition is intended to focus here
7 on the question of whether these filed rates conform to
8 the requirements of 4206, and to recommend procedures by
9 which the integrity of the intrastate regulatory process
10 can be maintained. We do not question either the State's
11 power to settle or its motives in settling the TAPS case.

12 We have not proffered evidence to question the
13 importance of settlement to the State, the State's need for
14 revenues, adverse affects of prolonged litigation, the
15 State's budget planning needs or the long-term development
16 plans for oil transportation on the TAPS. In short, we
17 believe the States Attorneys have done the best job possible
18 in negotiations and we applaud their efforts.

19 What the Staff has attempted to do is to analyze
20 TSM in the context of the Commission's statutes, its regula-
21 tions and its precedent in order to assist the Commission
22 in performing its statutory requirements and in maintaining
23 the integrity of the process. We have endeavored to make
24 practical recommendations as to solutions to the questions
25 presented here, and we have endeavored to draw conclusions

1 as to whether the results of this settlement and if the
2 results of this settlement are consistent with this Com-
3 mission's statutory standards and its traditional regula-
4 tory methodologies.

5 It is respectfully suggested that this role is con-
6 sistent with the role envisioned by the Legislature for
7 the Commission; that being to act as an independent and
8 active participant in the rate-setting process so as to
9 protect all intrastate interests.

10 There is, we believe, abundance evidence in this
11 record of the need for such an independent participation
12 by the Commission. As reflected by the State's briefs,
13 and I would add by in part Mr. Maynard's comments today,
14 this settlement grew in large part from the State's frus-
15 tration with FERC's non-action, and with the State's
16 consequential inability to secure a final decision from
17 that administrative process and with the great expense of
18 this litigation. Tesoro's express concern with the cost
19 of this proceeding is further evidence of those pressures.

20 The Staff believes that the lesson of the State's ...
21 experiences with the FERC administrative process is clear.
22 If TSM is approved, others who might otherwise challenge
23 the Carriers' rates will not exercise their 4206 rights
24 because the cost of such a rate challenge will be prohibi-
25 tive. This is a lesson which is inconsistent with the

1 Commission's regulatory role.

2 A variation of the first criticism suggests that the
3 Staff is unwilling or incapable of recognizing the inherent
4 trade-offs and benefits of settlement. The State's argument
5 suggests that the nature of the settlement precludes the
6 type of analysis performed by the Staff since any settle-
7 ment is simply barter. Such an argument assumes its own
8 conclusion. For if we applied the State's logic, neither
9 the Staff, nor an independent shipper, nor the Commission
10 could ever question this or any other settlement. All
11 objections could be answered by suggesting that compromise
12 and trade-offs are in the nature of settlements. The
13 State's criticism effectively suggests that no benchmark
14 can be used to measure TSM and that the Commission should
15 accept it because it is a settlement. This is inconsistent
16 with 4206's charge to the Commission.

17 Finally, the owners and the State claim that the
18 Staff has attempted to mislead the Commission. Their most
19 pronounced criticism concerns the Staff's reference to
20 systemwide differences between TSM and BTM, or the bench-
21 mark tariff methodology. For several reasons, this
22 criticism is devoid of merit.

23 First, the Staff's testimony focuses primarily on
24 tariffs not total revenues. This criticism is clearly an
25 attempt to shift attention from that fact.

1 Second, and most importantly, the Staff has only
2 discussed the systemwide effects of TSM in order to mirror
3 the analytical approach first chosen by the Carriers' own
4 witness Mr. Hildahl. It is noted that Mr. Hildahl in his
5 opening testimony never broke out interstate effects in
6 his analysis. To ensure that there was no confusion in
7 anyone's mind, at page 12 of Mr. Bertschi's testimony, he
8 expressly noted the fact that he was not demonstrating
9 intrastate effects. That fact seems to have been lost on
10 the settling parties.

11 Fifth, the Staff has never suggested that the APUC
12 could affect the FERC settlement or increase or reduce the
13 State's revenues. In some, this criticism is a curious
14 nit to pick. Suffice it to say that the State and the
15 Carriers are wrong.

16 The second question of the '83 stipulation and the
17 APUC's effect on the State's revenues has also been raised.
18 Not only do we not want to hide the effect of the stipula-
19 tion, as I have discussed already, we take comfort from
20 its existence and its effect. As to the State's and the
21 owners' varied criticisms of Mr. Bertschi's testimony, I
22 will defer extensive comment in favor of letting
23 Mr. Bertschi demonstrate the fallacies of those criticisms.
24 Suffice it to say that BTM is not equal to the Staff's
25 litigation position. His testimony is not based on

1 inconsistent data, and Mr. Bertschi's testimony fairly
2 demonstrates the wide divergence of TSM from traditional
3 regulatory methodology.

4 In closing, and in order to provide MAPCO, Tesoro,
5 and the State with the benefit of the State's bargain,
6 and while litigating the just and reasonable rates, the
7 Staff and Petro Star recommend the following schedule and
8 procedures for expeditious and fair resolution of the
9 Carriers' filed rates: Simultaneous with the Order dis-
10 approving the settlement, it is recommended that the
11 Commission should set a schedule for the cost of construc-
12 tion briefing; within one month after the APUC's Order
13 disapproving the settlement, the parties should be required
14 to file briefs recommending what issues remain to be
15 resolved by the Commission in light of the Supreme Court
16 remand; thereafter, the Commission should set an expedi-
17 tious schedule for the filing of testimony on those issues
18 as well as a hearing date. It is suggested that such a
19 hearing could be scheduled for five to six months or even
20 sooner after resolution of the issues. This is because,
21 first, the cost of construction record is closed; second,
22 the non-cost of construction record is closed through 1981,
23 and the updating of operating costs for '82 through '86
24 can be done from public filings or information already
25 produced by the Carriers. The record for Phase I issues

1 has also been closed, and supplementation of that record
2 for methodological questions is not as complicated as the
3 owners would suggest. In fact, the Staff is willing to
4 stipulate to the Phase I record.

5 And finally, the Staff is prepared to forego long or
6 involved auditing procedures in light of the effectiveness
7 of such audits presumably performed on TSM numbers by the
8 State in its review of TSM.

9 Next, the Staff believes that the hearing before the
10 Commission and the post hearing briefs can be resolved in
11 three to five months. Thus, with strict adherence to the
12 Commission's schedule, the parties could present the case
13 for a decision within eleven to thirteen months after the
14 Commission's Order disapproving settlement.

15 During this period, MAPCO and Tesoro could be protected
16 as follows: Pursuant to Section 410(b), the APUC could
17 order refunds for MAPCO and Tesoro calculated against TSM
18 rates by declaring the end of a phase of the TAPS pro-
19 ceedings. Since the only rates on file now are TSM rates,
20 MAPCO and Tesoro will be paying TSM rates pending resolu-
21 tion of these proceedings by the Commission. Should the
22 Carriers file revised higher rates, the Staff will move
23 to suspend them pursuant to Section 400 and ask the
24 Commission to set interim rates for as long as 18 months
25 at the level of TSM rates. These would be appropriate rates,

1 since all of the settling parties have already agreed that
2 those rates are at least fair and reasonable.

3 In sum, the Staff believes that all the public interests
4 sought to be served by TSM have either already been met
5 by the FERC settlement and the stipulation or can be fairly
6 served by the Commission action recommended here. Thank you.

7 JUDGE WILSON: Thank you, Mr. Bird.

8 Now is the time for the opening statement of Petro
9 Star. Mr. Lewis.

10 MR. LEWIS: Thank you very much.

11 OPENING STATEMENT ON BEHALF OF PETRO STAR

12 BY MR. LEWIS:

13 My name is Yale Lewis. I am appearing on behalf of
14 Petro Star. Previous counsel have emphasized two points;
15 one, that the record before this Commission would not
16 sustain a finding that TSM produces just and reasonable
17 rates. Secondly, there seems to be general consensus that
18 the effect of disapproving this proposed settlement would
19 not adversely affect the revenue of either the State or the
20 TAPS Carriers.

21 I would like to emphasize an additional point. This
22 Commission's ruling on the intrastate tariffs will have an
23 enormous impact on Petro Star. Petro Star pays full
24 tariff for all of the oil that it brings out of Prudhoe
25 Bay and takes into North Pole. The effect of those tariffs

1 have an enormous impact on the profitability of its
2 operations. The effect of those tariffs have an enormous
3 impact on the price that its purchasers pay for the refined
4 products of Petro Star. The intrastate tariff is also
5 going to have an enormous impact on the building of an
6 intrastate industrial base. Compared with these very
7 important attributes, the notion that the settlement that
8 this Commission should approve this settlement simply to get
9 it out of the way or because there are other interests of a
10 more vague public interest nature is simply not the proper
11 way for a regulatory proceeding to proceed.

12 The statutory test is just and reasonable tariffs.
13 That's the only thing that a shipper can rely upon. A
14 shipper has to know before a shipper makes an investment
15 in new facilities or in expanded facilities that they will
16 be able to pay just and reasonable tariffs. If the standard
17 becomes one that can be something less or something more
18 or something different simply because more powerful interest
19 can agree upon some other settlement and impose that as a
20 just and reasonable tariff, the smaller, independent
21 intrastate business person simply cannot have the certainty
22 that is necessary for that interest to make the investment
23 that they need to make.

24 The proponents of this settlement are trying to
25 direct your attention away from the statutory standard and

1 towards the reasonableness of their settlement. Well, it
2 is our position that the reasonableness of their settlement
3 is really not before you. Your statutory function is to
4 approve tariffs, are they just, are they reasonable, are
5 they non-discriminatory, are they non-preferential. The
6 reasonableness of the settlement reached between the State
7 and the Carriers is simply not part of your statutory
8 scheme. You approve tariffs. They have reached a settlement
9 which to them seemed adequate. We're not quarreling with
10 the justice of their decision to reach a settlement, but
11 that doesn't establish just and reasonable rates.

12 Petro Star and any other intrastate industry is
13 entitled to rely with certainty upon your willingness to
14 prescribe, determine just and reasonable rates regardless of
15 what some other entities think constitute a good settlement
16 for them.

17 The emphasis of the State's counsel on the reasonable-
18 ness of a settlement puts some -- places me in some dis-
19 advantage because I have enormous respect for them as
20 lawyers. I don't second-guess the instructions that their
21 clients gave them when they were instructed to settle the
22 case. Petro Star, nor I have ever criticized them for
23 reaching the settlement they reached. Our position is
24 simply that it did not produce just and reasonable rates.

25 The 6.4 percent real return plus inflation plus 100

1 percent equity assumption produces a rate of return that
2 is an enormously high rate of return. It is not a compro-
3 mise rate of return. The rate base adjustments in the
4 settlement make no reductions for cost of construction
5 overrun. Every penny that was put in comes out. All the
6 settlement does is say that for some of that investment
7 the Carriers don't get this very large rate of return.

8 There is a component of the settlement which pro-
9 vides that the Carriers will get 35 cents per barrel plus
10 an inflation adjustment plus a doubling under the 100
11 percent equity assumption for every barrel of oil that is
12 produced. If there is substantial oil on the Arctic Slope
13 that is not presently in a proven reserve category, that
14 will produce rates of returns that are infinitely high.
15 That factor alone makes it impossible for this settlement
16 to be approved to the just and reasonable settlement. It
17 is not cost-based, and that is the essential element of
18 a just and reasonable tariff in every jurisdiction in this
19 country, it has to be cost-based. 35 cents a barrel is not
20 cost-based.

21 The two other issues that are so critically
22 important to Petro Star, as they would be to any other
23 intrastate shipper, are the pumpability factor and the
24 pooling agreement. This agreement has a provision in it
25 which is called the pumpability factor. Well, the Carriers

1 are already charging enormous surcharges for pumpability.
2 It's very hard to understand. The State presented very
3 persuasive testimony in the TAPS proceeding in the federal
4 TAPS proceeding and in this proceeding which was attached
5 to Petro Star's filing which makes it quite clear that
6 there is no engineering and no economic basis at all for
7 the pumpability factor.

8 Yet already before the ink is really dry on the
9 settlement, enormous surcharges are being charged to
10 Petro Star for oil coming out of Kuparuk based upon the
11 pumpability factor. Now the State, perhaps somewhat
12 embarrassed by this, says we shouldn't be too concerned,
13 you shouldn't be too concerned, we can complain about it
14 later.

15 Well, Petro Star is paying that surcharge on oil
16 that it shipped in 1986. That issue is real, it's now,
17 it can't be resolved by saying, "Well, Commission,
18 approve this agreement now and that issue can be dealt
19 with later". That issue has to be dealt with now because
20 it is affecting Petro Star now.

21 Finally, the pooling agreement is dealt with at
22 length in our testimony and I won't go into it further
23 here because it is well laid out in Professor Oster's
24 testimony and our briefs. But there are a number of
25 elements of this so-called settlement agreement that

1 preclude a finding of a just and reasonable tariff and
2 that are enormously detrimental to Petro Star.

3 We urge the Commission to follow the Staff's recom-
4 mendation to conclude the hearing as rapidly as possible,
5 establish just and reasonable rates. We believe that can
6 be done within a year. We believe that the suspension
7 power, the 18-month suspension power will preserve the
8 status quo during this period. Everybody will get the
9 benefit of their bargain, except MAPCO will lose its
10 opportunity cost for 18 months. Nevertheless, it will
11 continue to pay TSM tariffs, as will everybody else. The
12 State gets its revenue, the companies get their revenue,
13 you get the chance to exercise your statutory function to
14 determine just and reasonable rates. By the end of 18
15 months the status quo will have been maintained and you
16 will have a decision in place. We urge you to do that.
17 Thank you for your time and attention.

18 -- JUDGE WILSON: Thank you, Mr. Lewis. At the pre-
19 hearing conference held this morning, Arctic Energy
20 Company indicated that it wished to waive its opening
21 statement.

22 Now is the time when the Commission encourages
23 interested members of the public to comment on the subject
24 matter of this hearing. Are there any members of the
25 public who wish to make a statement at this time? I have a

EXCERPT TRANSCRIPT

(Excerpt of transcription after the morning break.)

JUDGE WILSON: Mr. Maynard.

MR. MAYNARD: Thank you, Judge Wilson, members of this Commission. Governor Cowper has requested that I make a statement to correct a potential misimpression concerning this Administration's views and policies on settlements of this type.

The Governor believes that as a matter of policy these types of disputes should not be settled but instead should be litigated to conclusion. For that reason alone, if he had been in office, the Governor would not have entered into this Agreement and of this Settlement. Nonetheless, the Governor understands that the previous Administration had a different policy on settlements and entered into this Settlement under that different policy.

Further, the Governor has not independently reviewed either the merits or demerits of this Settlement as a settlement. Since the State will therefore continue to support this Settlement, it will continue to make itself available to and assist the Commission in its review of this Agreement.

Thank you, Judge Wilson.

JUDGE WILSON: Thank you, Mr. Maynard.

COMMISSIONER AGI: Are we modifying the State's

1 opening statement in any respect?

2 MR. MAYNARD: To the extent that the opening
3 statement gave the impression that the Governor's policy
4 was that settlements as a matter of policy were the way to
5 go, the opening statement is modified.

6 COMMISSIONER AGI: As far as participation in front
7 of this Commission by the Attorney General's Office?

8 MR. MAYNARD: In future proceedings?

9 COMMISSIONER AGI: In future proceedings.

10 MR. MAYNARD: There has not been any specific dis-
11 cussion of that. Nothing to my knowledge has changed that,
12 but there's been no discussion of that.

13 (End of requested excerpted portion of proceeding.)

14 * * *

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ELF ALTERNATIVES

DELAY ONLY

- \$87 million new revenue available in FY 88 (30th percentile).
- Revenue rises gradually through 1992, then drops abruptly by \$114 million when ELF again applies.
- Maintains Prudhoe tax at 15.0 percent.
- Kuparuk tax rate unchanged at 8.1 percent.
- No change in tax rates at Milne Point, Endicott, Lisburne, or other marginal fields.
- PEL adjustment unchanged. Falling oil prices could have magnified effect on severance tax revenue, i.e., 50 percent drop in wellhead price could produce 90 percent drop in revenue. State prohibited from asking for PEL adjustment if oil prices rise.
- Does not change provisions of current law allowing producers in large fields to gain tax rebates by adding wells producing at or near 300 barrels per day.

HOUSE SUBSTITUTE

- \$94 million new revenue available in FY 88 (30th percentile).
- Revenue rises gradually through FY 93, then declines gradually.
- Prudhoe tax rate reduced to 14.8 percent.
- Kuparuk tax rate increased to 11.7 percent.
- Decreases tax rates for Milne Point, Endicott, Lisburne, and other marginal fields. Eliminates tax for all existing Cook Inlet oil fields.
- Reduces chance that PEL adjustment would magnify effect of falling prices on severance tax revenue. State is allowed to petition for upward PEL adjustment.
- Eliminates negative tax rates on incremental revenue, but retains incentives for incremental production

1/87-2/88 N.S. K1/5 COUNTS

		<u>Std</u>	<u>ARCO</u>	<u>Comments</u>
Jan 87		2 End PB	Lib PB Kup	
Feb	same			
Mar.		2 End PB	Kup Lib.	drop ARCO PB
Apr.	same			
May	same			
June		2 End 2 PB	Kup Lib	add Std PB
* July	same			
Aug	same			
Sept		2 End 2 End	Kup Lib PB	add ARCO PB
Oct.	same			
Nov.	same			
Dec. 3		2 End	Kup	add Std A
Jan 88		3 PB	Lib PB	
+ Feb. 88		2 End 3 PB 1 W end/PB	Kup Lib PB	add Std PE (W. end - Eileen)

* - 7/22/87 - Petroleum info Weekly - Susan Andrews of ARCO gives advance notice of increased PE development drilling - increased activity "strictly the result of higher oil prices"

+ - By 2/88 Standard he increased its Puddle rig count by 3 (since 1/87) and brought on W. end/Eileen ARCO is same as 1/87 but had dropped/added one

Cotten-

I can explain but I need
to go to AMI now - want me
to stay? I'm in the Gallery.
Plus some short bullets in
your chair

AS

Alaska State Legislature

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IN SESSION:
POUCH V
JUNEAU, ALASKA 99811
(907) 465-4714



Senator Mitch Abood
CHAIRMAN

Senate Committee on State Affairs

March 25, 1988

The Honorable Steve Cowper
Alaska State Capital
P.O. Box A
Juneau, Alaska 99811

Dear Governor Cowper:

Thank you for your letter, dated today, requesting a hearing on CSHB 164, the so-called ELF bill.

Your letter states "there seems to be some confusion here." I personally can't understand why this is. Be that as it may, there have already been five hearings held on this bill, during which extensive public testimony was taken. Because none of the issues have changed, it's not clear what new information would be gained by holding yet another hearing on this tax increase legislation.

In order to have all of the information on these public hearings, I would greatly appreciate any assistance you could provide on a particular matter relating to the bill. Yesterday, in the interest of furthering the public process, I requested a complete set of the file material the House Finance and Resources Committees accumulated during their review of HB 164. Representative Adams was kind enough to provide me with these materials yesterday afternoon for the House Finance Committee -- the same day I requested them.

Unfortunately, the House Resources Committee has yet to provide me with any of the requested materials. Because I am considering holding a hearing of the Senate State Affairs Committee on CSHB 164, it would be most appreciated if you could contact the House Resources Committee Co-Chairmen, Representative Cotten and Representative

Dear Mitch.

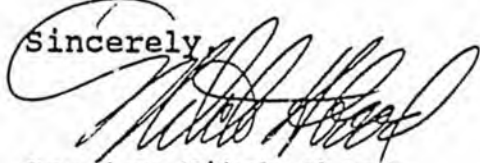
Hold a hearing and you will receive more material than you care to ever see

Sund

Herrmann, and request that they do what they can to find their files and provide me with a copy.

Thank you for any assistance you may be able to provide.

Sincerely,

A handwritten signature in black ink, appearing to read "Mitch Abood", written in a cursive style.

Senator Mitch Abood,
Chairman

cc: All Senators
All Representatives
Enclosures

Alaska State Legislature

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IN SESSION:
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Senator Mitch Abood
CHAIRMAN

Senate Committee on State Affairs

Hand-Delivered

March 24, 1988

Representative Sam Cotten, Co-Chairman
House Committee on Resources
P.O. Box V
Juneau, Alaska 99811

Dear Representative Cotten:

Could I please have a complete set of the file material which the Resources Committee used in its review of HB 164, "An Act relating to the oil and gas properties production tax; and providing for an effective date."

Thank you for your assistance in this matter.

Sincerely,

A handwritten signature in black ink, appearing to read "Mitch Abood".

Senator Mitch Abood
Chairman

Alaska State Legislature

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Senator Mitch Abood
CHAIRMAN

Senate Committee on State Affairs

Hand-Delivered

March 24, 1988

Representative Adelheid Herrmann, Co-Chairman
House Committee on Resources
P.O. Box V
Juneau, Alaska 99811

Dear Representative Herrmann:

Could I please have a complete set of the file material which the Resources Committee used in its review of HB 164, "An Act relating to the oil and gas properties production tax; and providing for an effective date."

Thank you for your assistance in this matter.

Sincerely,

A handwritten signature in black ink, appearing to read "Mitch Abood", written over a horizontal line.

Senator Mitch Abood
Chairman

&k12H

Alaska State Legislature

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Senator Mitch Abood
CHAIRMAN

Senate Committee on State Affairs

Hand-Delivered

March 24, 1988

Representative Al Adams, Chairman
House Committee on Finance
P.O. Box V
Juneau, Alaska 99811

Dear Representative Adams:

Could I please have a complete set of the file material which the Finance Committee used in its review of HB 164, "An Act relating to the oil and gas properties production tax; and providing for an effective date."

Thank you for your assistance in this matter.

Sincerely,

A handwritten signature in black ink, appearing to read "Mitch Abood", written over a horizontal line.

Senator Mitch Abood
Chairman

4/87 N.S. RIG COUNTS

		<u>Sta</u>	<u>ARCO</u>	<u>Comments</u>
Jan 87		2 End PB	Lib PB Kup	
Feb	same			
Mar		2 End PB	Kup Lib	drop ARCO
Apr	same			
May	same			
June		2 End 2 PB	Kup Lib	add set PE
* July	same			
Aug	same			
Sept		2 End 2 End	Kup Lib PB	add set PE
Oct	same			
Nov	same			
Dec. 7		2 End	Kup	add set B
Jan. 88		3 PE	Lib PB	
+ Feb. 88		2 End 2 PE 1 Ward/PB	Kup Lib PB	add set A (W. end - E. end)

* - 7/22/87 - Petroleum Info Weekly - Susan Andrews of ARCO gives advance notice of increased PE development drilling - increased activity "strictly the result of higher oil prices"

+ - by 2/88 Standard has increased its Prudhoe rig count by 3 (since 1/87) and brought on W. end/E. end ARCO is same as 1/87 but had dropped/added one

Model Resolution Supporting Adjustment of the Economic Limit Factor (ELF)

WHEREAS the State of Alaska will lose approximately \$200 million in the next fiscal year from the application of the Economic Limit Factor (ELF) to Prudhoe Bay;

WHEREAS the revenue losses to the State are projected to total more than \$1 billion over the next five years;

WHEREAS the Alaska economy is only now beginning to emerge from the deepest recession it has suffered in 30 years;

WHEREAS without the additional revenue the state budget for FY 89 will be almost \$400 million in the red;

WHEREAS cuts of this size would have a devastating effect on the economy and on Alaska's local governments;

WHEREAS the economic limit factor (ELF) was originally intended to serve as a tax break to encourage oil production in marginal fields;

WHEREAS the Prudhoe Bay oil field is in no sense a marginal field, but is instead the largest oil field in North America, and appears to be one of the most profitable oil fields in the world;

WHEREAS the application of the Economic Limit Factor to the Prudhoe Bay oil field is thus wasteful and unnecessary;

WHEREAS the application of the Economic Limit Factor actually discourages oil production at a truly marginal field such as Milne Point;

BE IT RESOLVED that the Alaska Legislature enact legislation that would adjust the Economic Limit Factor to make it work as originally intended so as to encourage oil production at marginal fields and not give an unneeded tax break to the Prudhoe Bay field, the largest and most valuable field in North America.

GETTING ALASKA'S SHARE OF OIL REVENUES

by Cliff Davidson (1)

Alaskans own Prudhoe Bay, the largest and most prolific oil field in U.S. history. We have derived tremendous benefits from its development: the Permanent Fund, our schools, many municipal improvements, and government services for children, the elderly and the disabled.

However, our share of the revenue from this field has recently been reduced, while the major oil companies are increasing their share and proclaiming their profitability in a tough oil market. For this fiscal year, about \$185 million has been directly transferred from Alaska to the corporate treasuries of several major international oil companies.

All over the state, people who need school improvements and municipal services are wondering why the Legislature allowed a reduction in oil and gas taxes when our state revenues are in precipitous decline.

The answer to the question is that the Legislature scheduled the tax break back in 1981, when oil prices were rising and it was thought that Prudhoe Bay would be in

1 - Cliff Davidson represents Kodiak in the State House and is a member of the House Resources Committee.

decline by 1987. Today it is clear that the industry will continue to operate, quite profitably, if the tax regime is restored. Yet the State Senate has refused to act on the oil tax bill, despite Governor Cowper's support for it and the State House's.

Last year the House passed a bill, introduced at the Governor's request, that did two important things:

- * prevented large tax breaks for giant oil fields like Prudhoe and Kuparuk, where tax incentives aren't needed, and

- * provided a new tax incentive for production from every other known field in Alaska, including marginal fields such as Endicott, Lisburne, and Milne Point, which was shut down in 1987 because it was uneconomic.

This approach makes sense. Forbes magazine recently reported that Atlantic Richfield is one of the most profitable oil companies in the world, and guess where the company gets 67% of its oil? From Kuparuk and Prudhoe Bay. Tax breaks are simply unnecessary for these oil fields.

The chief executive of Atlantic Richfield recently boasted that the company's profits are the "best in the

industry." The company has also publicly reported that it increased its Alaska production while reducing production from other sources. These aren't the actions of a company producing from a marginal property.

Meanwhile, British Petroleum last year completed its acquisition of Standard Oil. Now it owns 100% of that company, which got 98% of its oil production from Alaska. And Kuwait's national oil company has purchased more than 20% of BP. These aren't the actions of corporations worried about the profitability and potential of Alaska oil and gas production.

Some industry representatives claim that the tax break has encouraged more drilling on the North Slope. No proof has been offered that the new drilling provides Alaskans extra jobs or that the long-term production of Prudhoe and Kuparuk is being increased. Instead, we might just be seeing the hastier depletion of oil and gas reserves.

Industry representatives also talk about "tax stability." They imply that there was a compact between the 1981 Legislature and the oil and gas industry to install a tax break in 1987. But they neglect to mention that there were other issues -- legislative instability, legal battles, and inaccurate production projections -- that influenced the

1981 Legislature. They also don't seem to realize that today's legislators need to deal with today's problems.

In fact, it's clear that the industry actually supports tax changes when those changes benefit the industry. In 1981 the industry came to the Legislature (in a time of oil price inflation) and asked for tax breaks. The Legislature responded by instituting a new "unitary" tax system. Since that time, Alaskans have foregone billions of dollars worth of revenue that would have been collected under the former system.

Alaskans have a choice here: shall we continue to forfeit tax revenues that could be put to many purposes around the state, or shall we go ahead and collect taxes that won't harm the industry and will bring us back to where we stood a year ago? I'm strongly supportive of Governor Cowper's effort to rescind the oil tax break, and I'm glad that the House and the Governor are working together on a tax system that will truly serve the interests of all Alaska.

OIL WATCH

Division of Policy
Office of the Governor

DATE: March 1, 1988

PREPARED BY: R.A. Fineberg

Spot Prices

The ANS Gulf Coast spot price dropped to \$13.85-13.90 today. Over-supply and Saudi discounting again appear to be the principal factors in the latest price slump, which has driven the spot price down almost to its 12-month low (which occurred just before Christmas) and over \$2.00 below the price at the beginning of the year.

The Department of Revenue estimates current North Slope production at 2.03 million barrels per day.

Attached are updated graphs showing spot, contract and posted prices. Since the last time we provided these graphs (Oil Watch, January 14, 1988), ANS Gulf spot and posted prices have levelled out in the \$15 range. This makes \$15 a reasonable basis for projecting contract prices in the near-term -- at least prior to last week's drop.

Effects on Mean Forecast for FY 88 and FY 89

A simplified model borrowed from the Department of Revenue indicates that if the ANS Gulf price holds at \$15.00 for the remainder of the fiscal year, FY 88 revenues should be approximately \$40 million below the \$2,095 million mean forecast of Feb. 11.

If \$15.00 held throughout FY 89, the February 11 mean forecast for FY 89 (\$1,981 million) would be approximately \$170 million high.¹

Delphi Forecast

The forecast group will meet in Anchorage Monday and Tuesday, March 7-8. The completed forecast is expected early in April.

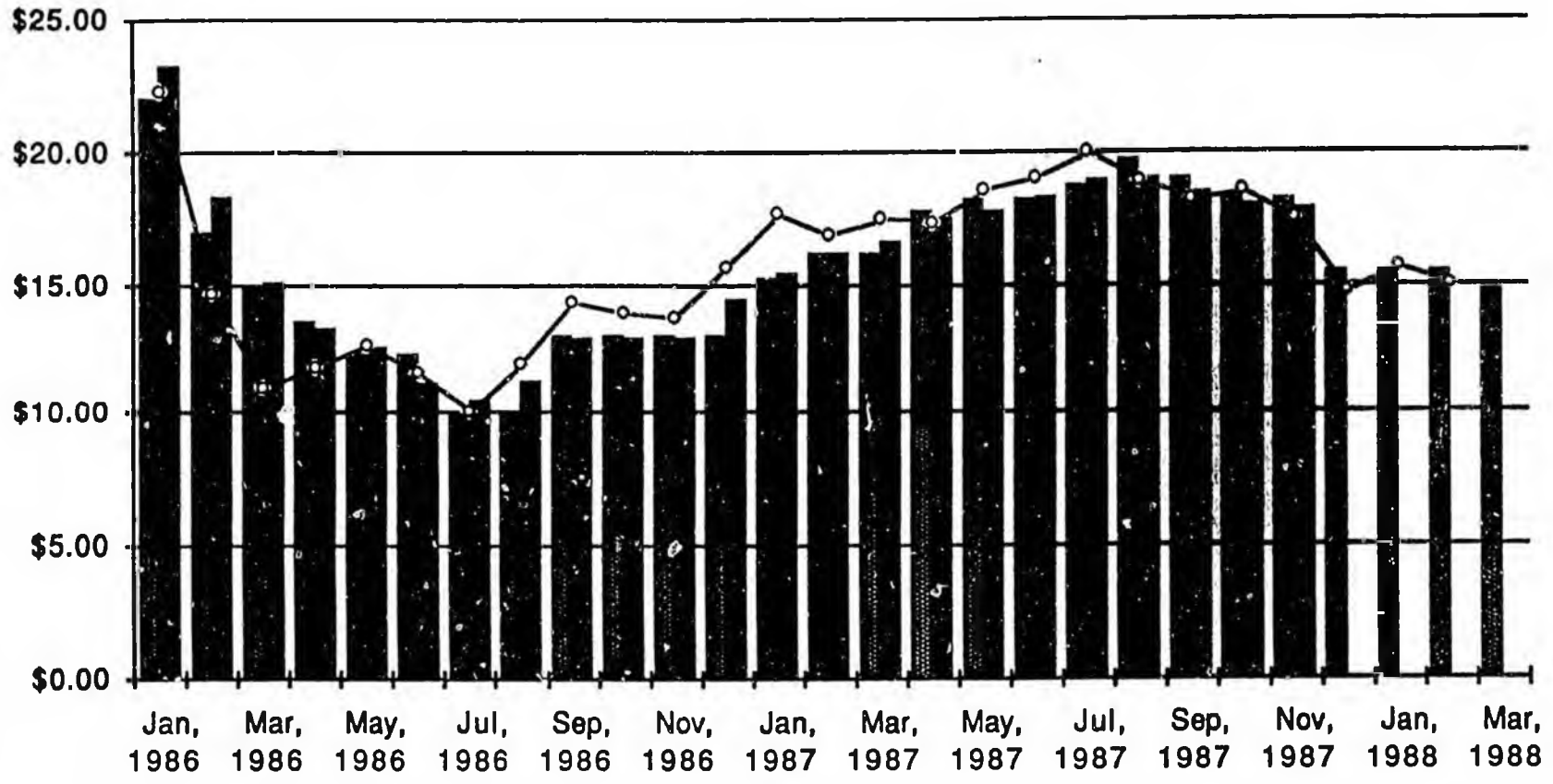
¹ The simple rule of thumb is that a \$1.00 change in price over 12 months changes Unrestricted General Fund revenues by approximately \$130 million. The FY 89 mean forecast price for ANS at the Gulf is \$16.32. $\$1.32 \times \$130 = \$172$ million.

Distribution:

Governor Steve Cowper
Garrey Peska, Chief of Staff
Mary Halloran, Director, Division of Policy
Jay Hogan, Director, Division of Budget Review
Hugh Malone, Commissioner of Revenue
Lennie Gorsuch, Deputy Commissioner of
Natural Resources
Cameron Kashani, Legislative Finance

ANS Gulf Actual v. Spot & Posted Prices (1986-88)

\$ / Barrel



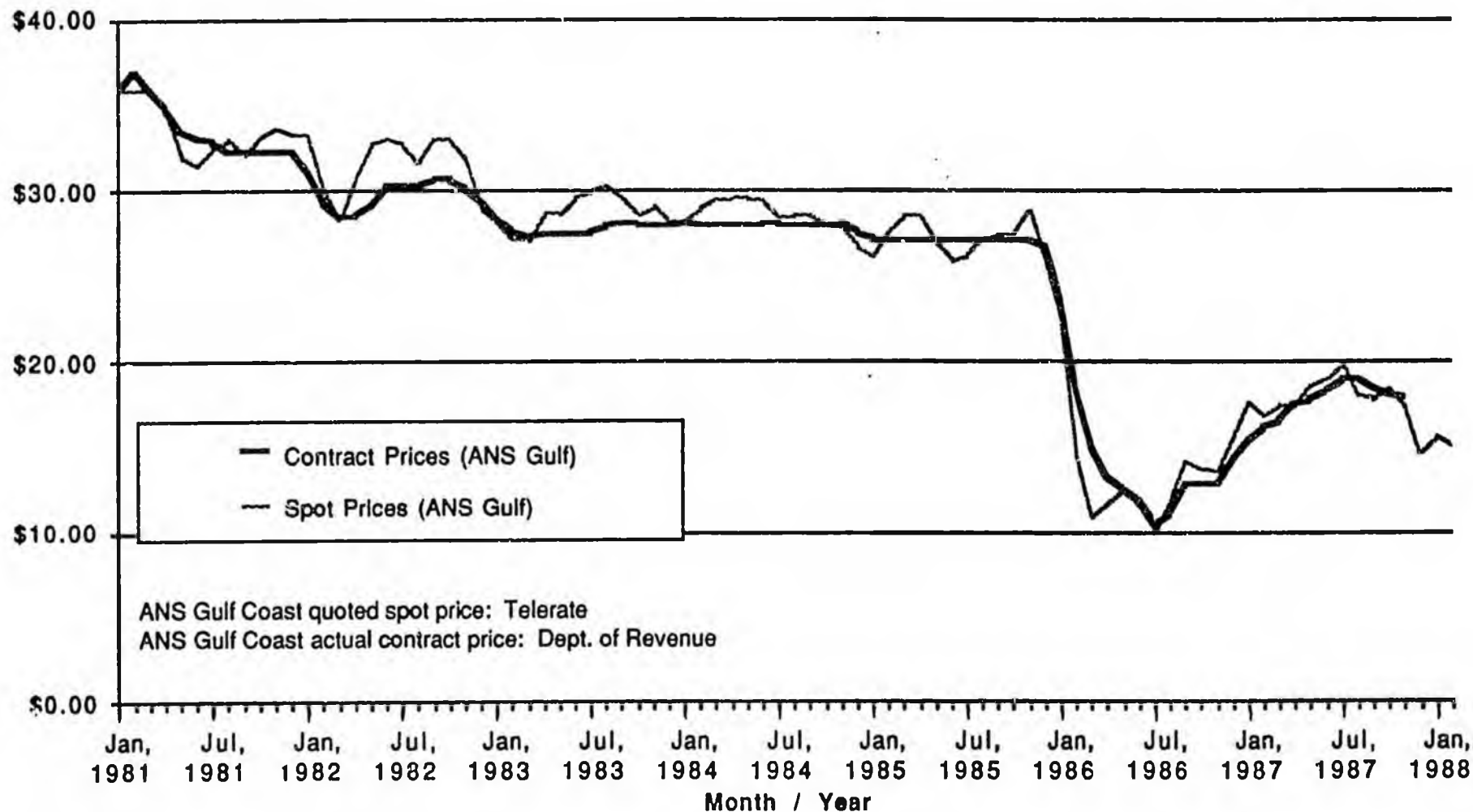
- Gulf Posted (Sohio)
- Gulf Actual Contract
- ANS Gulf Spot

Source: Division of Policy

(from Standard posted price and DOR data; 3/1/88)

ANS Gulf Spot and Contract Prices (1981-1988)

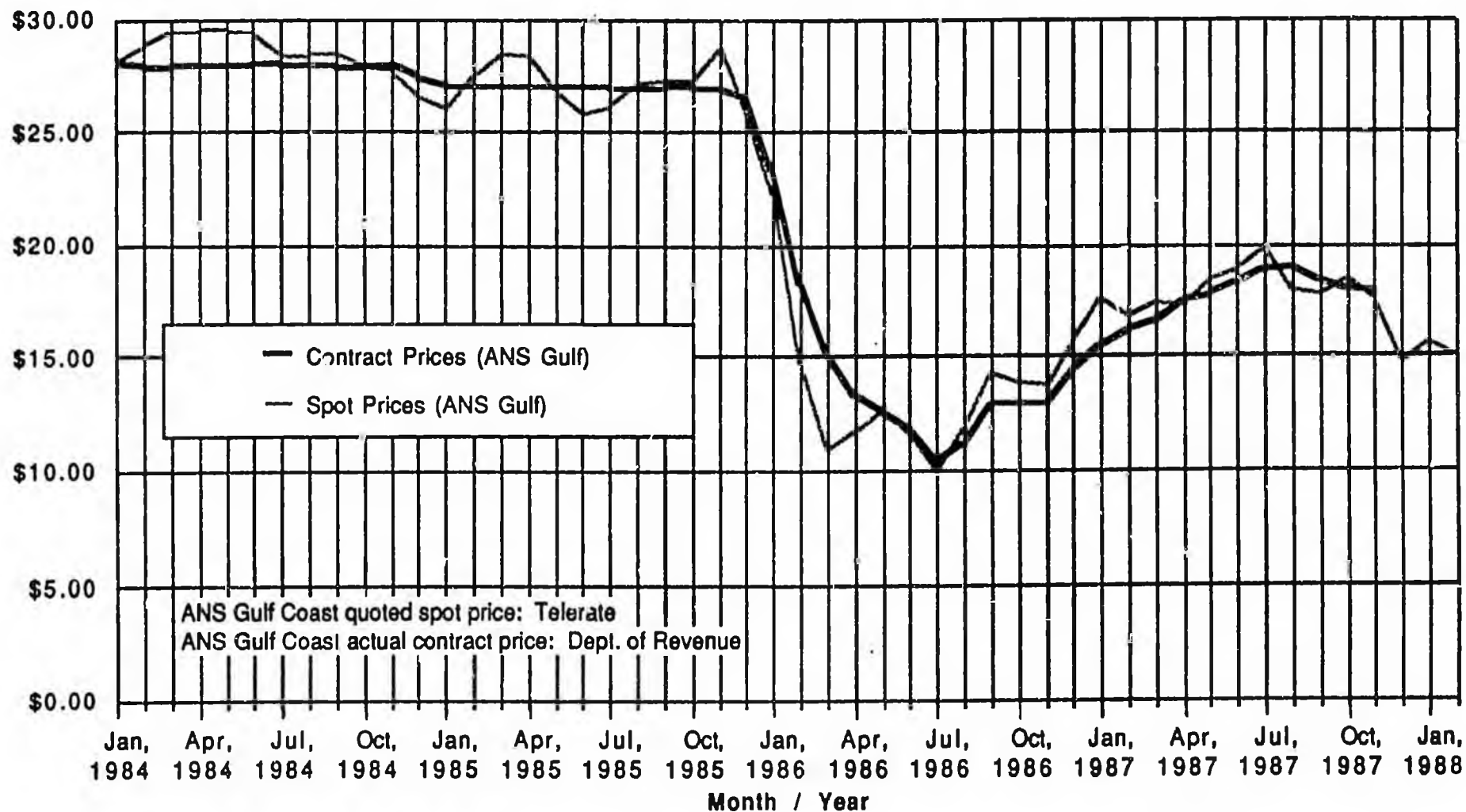
\$ / Barrel



Source: Division of Policy, 3/1/88

\$ / Barrel

ANS Gulf Spot and Contract Prices (1984-1988)



Source: Division of Policy, 3/1/88

3/25/88

Oil Profits Mostly Leaving Alaska

by
Gregg Erickson

Nineteen eighty-seven may have been a tough year for many Alaskans, but it was a very good year for the oil industry. According to the February 1 issue of *Petroleum Intelligence Weekly* (PIW), a respected oil industry trade publication, North Slope profits were \$1.56 billion, or \$4.3 million per day. Based on averages over January and February, current profits are even better--\$6.1 million per day.

The PIW report provides a fascinating, accountant's-eye view of industry operations in Alaska. The costs of keeping oil flowing from the North Slope fields -- labor, insurance, fuel, maintenance, and the like -- currently are \$1.7 million per day. That amount shrinks, however, compared with the state's daily \$4.7 million in royalties and various taxes.

The breakdown among the taxes is interesting. All profitable corporations in Alaska pay state corporate income taxes. For most non-oil companies the tax rate on Alaska income is the nominal 9.4 percent rate. According to the PIW article, the petroleum firms pay only 3 percent. The difference is presumably a result of the special system for assessing taxable income granted the industry in 1981. Savings to the industry from this difference: \$750,000 per day.

The PIW analysis assumes that the oil companies pay the full 34 percent federal tax on their Alaska income. That may be unrealistically high, but if it is true the feds are making daily collections of \$2.8 million.

Oil companies made major investments in Alaska to produce the oil and move it to markets. Companies recover those investments through depreciation charges. The PIW figures don't include pipeline depreciation, but for everything else depreciation comes to \$4.5 million per day.

Profits and depreciation are both cash returns to the companies; depreciation pays back the companies' investment, and

profits (currently \$6.1 million per day) are the cash left after depreciation and other costs have been covered. Taken together, profits and depreciation make up the cash flow that the companies must either reinvest in Alaska or take elsewhere. The total comes to a daily \$10.6 million.

Most of these dollars are going elsewhere. PIW doesn't provide figures for the rate of reinvestment, but producers say their current Alaska drilling programs are costing about \$400 million annually. For a generous estimate of bonus bids and costs of constructing of new North Slope facilities add a further \$300 million. That adds up to less than \$2 million a day.

In an accountant's terms, the oil industry is liquidating its assets in Alaska. For every \$2 the oil industry is reinvesting, it is taking \$8 out.

Why such a disparity? Oil companies allocate new investment based on expected returns. They clearly believe they can find good reinvestment opportunities for only about \$2 out of every \$10 they make in the state. That is not too surprising, since returns on future investments are hardly likely to equal returns now flowing from the super-giant, super-profitable Prudhoe and Kuparuk fields.

Do the companies deserve criticism for reinvesting so little of their Alaska returns in the state? That is an important question, but it is not an easy one. Making hard-headed decisions on deploying assets is what private firms do best. Doing that job well has won ARCO a reputation as one of the nation's most imaginative and best run corporations. Government should be cautious about interfering.

On the other hand, the \$8 cut of every \$10 leaving Alaska is a very high price to pay for the \$2 being reinvested. Certainly the dollars departing the state contribute little to Alaska's future.

Gregg Erickson is a senior economist with the state Division of Policy.

MEMORANDUM

State of Alaska

TO: The Honorable Steve Cowper
Governor


DATE: March 23, 1988

FILE NO: 0074q

TELEPHONE NO: 465-2300

THRU:

SUBJECT: March 1988 Revenue
Forecast


FROM: Hugh Malone, Commissioner
Department of Revenue

Commissioner's Preface

This forecast is the first since the release of the Gault Report on Alaska's revenue forecasting system.

It represents a fundamental change. Before, all revenue outcomes were assigned probabilities by the forecasters, but one case was advocated. Usually, that forecast (or some other) was felt to compel one fiscal policy over another. Here, though, policymakers are given a range of scenarios, each with its own assumptions on the economic, political, and other factors that may impact future oil prices and future revenues.

Among the several advantages of this approach, two stand out. First, all policymakers will more directly share in the responsibility for selecting the forecast number on which action is taken. More importantly, a forecast, no matter how accurate it may prove to be, does not dictate actions. Forecasts are not a substitute for debate on the size of budgets, the level and kinds of revenues, the amount of borrowing, or the savings we add to reserves or the Permanent Fund.

Administrative Notes

No final decision has been made as to how many complete forecasts (as opposed to updates) will be prepared each year, and by what dates. The prime considerations are the needs of the Governor, CMB, and the Legislature in the budget cycle. On the other hand, time must be allowed to judge the effects of actions by OPEC, especially their regular meetings in early June and early December.

Contents of Forecast

Oil Price Scenarios - an outline of the basic assumptions for the low, mid, and high case scenarios.

Table I - Revenue Summary - petroleum revenues, non-petroleum receipts and, finally, total unrestricted revenues. For the perspective it provides, the various scenarios are compared to the mean case last September, 1987.

- Figure I - Graph of FY 88-90 Estimates.
- Table II - Key Statistical Assumptions - oil prices, tariffs, thruput, etc.
- Table III - Detail of Revenues by Categories
- Figure II - Comparison of Historical Revenues to new Estimates
- Figure III - Recent History of ANS Crude Prices

Memo to Commissioner Hugh Malone Concerning the Preliminary Steps to Implement the Gault Report.

OIL PRICE SCENARIOS

Introduction

We have recently completed our March forecast of petroleum production revenues. The oil market over the last month can be characterized as deteriorating. This is due mostly to the reluctance of large oil reserve countries like Saudi Arabia to act as "swing" producers to defend price in a soft market. As a result, the oil revenue outlook is on balance lower than when we made our last forecast in September. At that time, we felt that prices would fall from the then current level of \$18.00/bbl to the \$15.00/bbl level in the spring. As it turned out, the price has fallen much further as evidenced by the current Standard/BP posted ANS price of \$13.75/bbl at the U.S. Gulf.

As a result of methodological review, we have implemented a scenario approach to attempt to clarify the specific market events and key player behavior which contributes to the large amount of uncertainty associated with the future of oil prices. Specifically, we have limited our analysis to three alternative scenarios of events leading to much different future oil prices. For the purposes of this memo, only the short run will be addressed.

The scenarios are driven by completely different assumptions about the price of oil. The primary requirements for the scenarios was that they be plausible and that they reflect a low, high, and mid range of the prices felt possible in the future. A brief description of each scenario as developed for the short term forecast follows.

Scenario 1 - Low

	<u>FY 88</u>	<u>FY 89</u>	<u>FY 90</u>
	(Millions of Dollars)		
Total Unrestricted Revenues	2,085.1	1,337.6	1,285.1
	(Price in \$ per barrel)		
(1) West Coast	14.36	10.92	10.77
(2) Gulf Coast	15.42	11.93	11.78
(3) Weighted Average	14.80	11.32	11.16

The low scenario is based on the following assumptions:

- 1) Slow world economic growth over the next two years in the range of 1.0 to 1.5% per year.
- 2) Because of the investments made in recent years to develop new fields, non-OPEC production is assumed to average 500,000 barrels per day higher in both 1988 and 1989.
- 3) The Iran/Iraq war continues to rage in starts and fits with no material impact on shipments of oil from the Persian Gulf. Iran output will be constrained to 2.0 million barrels per day while Iraq will produce 3.0 million barrels per day.
- 4) OPEC market share will therefore range between 17.5 and 17.7 million barrels per day.
- 5) OPEC producers will try to sell up to 18.6 million barrels per day.
- 6) OPEC will therefore be unable to move or hold price much above the lower end of the range over which the market has cleared over the past two years.

Scenario 2 - Mid

	<u>FY 88</u>	<u>FY 89</u>	<u>FY 90</u>
	(Millions of Dollars)		
Total Unrestricted Revenues	2,111.9	1,772.5	1,825.9
	(Price in \$ per barrel)		
(1) West Coast	14.82	14.17	14.95
(2) Gulf Coast	15.86	15.19	15.96
(3) Weighted Average	15.24	14.58	15.34

The middle price scenario is based on the following assumptions:

- 1) Modest world economic growth in the range of 2.0 to 2.5%.
- 2) Non-OPEC production will average 500,000 barrels per day higher in both 1988 and 1989 due to investments made in prior years.
- 3) The Iran/Iraq war continues to rage on in fits and starts with no major impact on the flow of oil from the Persian Gulf.
- 4) OPEC market share will range between 17.8 and 18.0 million barrels per day on average for 1988 and 1989.
- 5) OPEC tightens production discipline at the June meeting by allowing Iran to produce outside an official quota with Iraq trimming production to 2.3 million barrels per day. Strengthening prices in the summer result in OPEC production approaching 20.0 million barrels per day. This creates the seasonal inventory accumulation which has historically become a problem in the spring when no single producer or group of producers are willing to curtail production below quota to meet changes in seasonal demand patterns.
- 6) Price will therefore swing within the consensus range according to this OPEC cycle.

Scenario 3 - High

	<u>FY 88</u>	<u>FY 89</u>	<u>FY 90</u>
	(Millions of Dollars)		
Total Unrestricted Revenues	2,156.4	2,316.8	2,424.9
	(Price in \$ per barrel)		
(1) West Coast	15.42	18.13	19.11
(2) Gulf Coast	16.46	19.15	20.14
(3) Weighted Average	15.84	18.54	19.51

The high price scenario assumptions are as follows:

- 1) Strong world economic growth of 4% per year.
- 2) Non-OPEC production increases by 500,000 barrels per day in 1988 but no additional production in 1989.
- 3) The Iran/Iraq war continues, however, the combined production of both countries does not exceed 5.0 million barrels per day.
- 4) This implies an OPEC market share of 18.0 to 18.2 million barrels per day in 1988 and 18.7 million barrels per day in 1989.
- 5) OPEC sticks to a realistic quota of between 17.8 and 18.0 million barrels per day with key discretionary producers observing "seasonal" quotas.
- 6) Oil prices remain relatively stable close to the current official OPEC fixed price.

HM:JBR:m11

TABLE I

MARCH 1988 ESTIMATES OF UNRESTRICTED
 PETROLEUM AND NON-PETROLEUM REVENUES
 COMPARED TO SEPTEMBER 1987 ESTIMATES
 (Millions of Dollars)

PETROLEUM REVENUES

	<u>FY 1988</u>	<u>FY 1989</u>	<u>FY 1990</u>
SEPTEMBER MEAN ESTIMATE	1728.1	1676.1	1839.2
Oil Price (Average \$/bbl)	(16.45)	(15.62)	(16.37)
MARCH LOW SCENARIO	1750.6	1080.2	1067.1
Change from September	22.5	-595.9	-772.1
Oil Price (Average \$/bbl)	(14.80)	(11.32)	(11.16)
MARCH MID SCENARIO	1777.4	1476.1	1598.9
Change from September	49.3	-200.0	-240.3
Oil Price (Average \$/bbl)	(15.24)	(14.58)	(15.34)
MARCH HIGH SCENARIO	1821.9	2003.4	2129.9
Change from September	93.8	327.3	290.7
Oil Price (Average \$/bbl)	(15.84)	(18.54)	(19.51)

NON-PETROLEUM REVENUES*

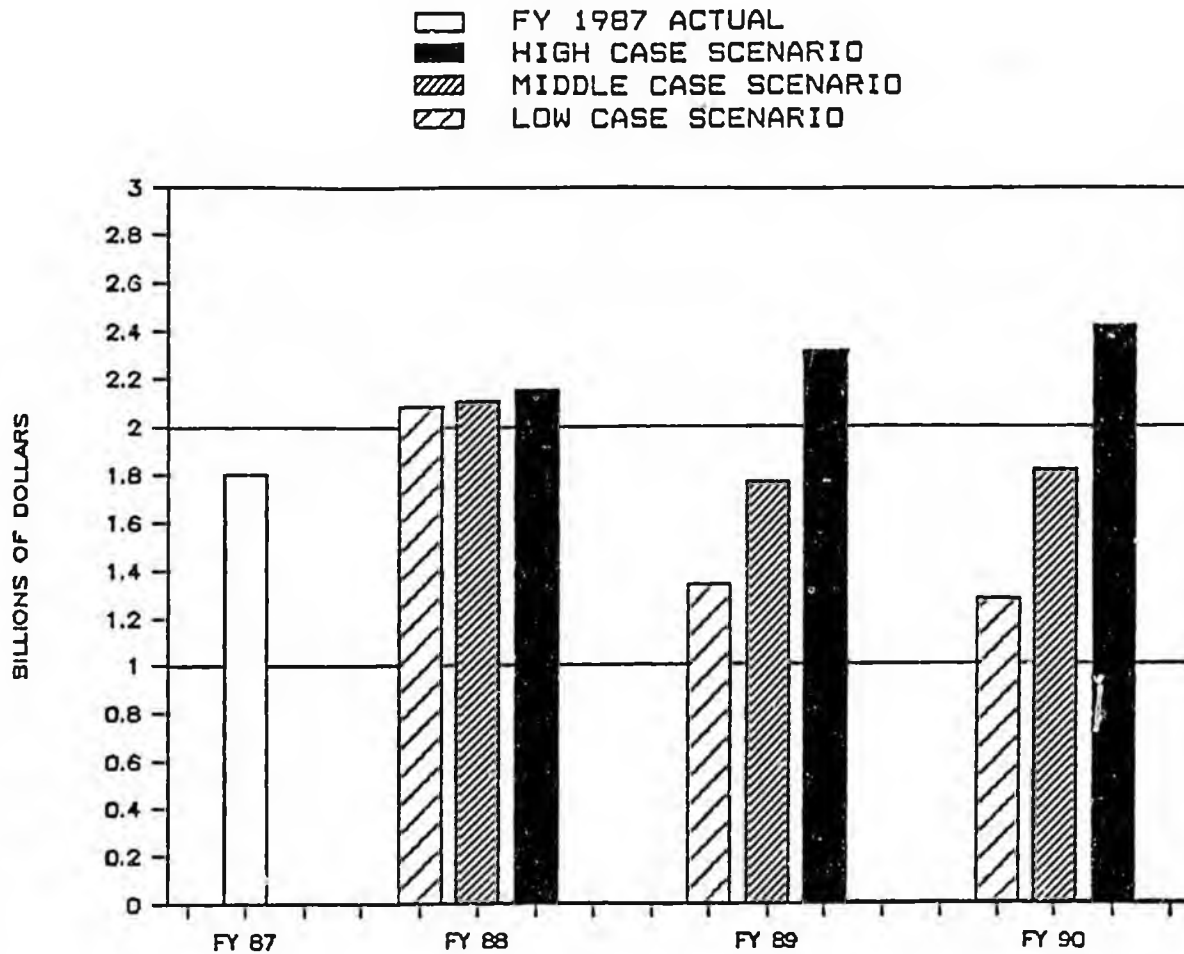
	<u>FY 1988</u>	<u>FY 1989</u>	<u>FY 1990</u>
SEPTEMBER MEAN ESTIMATE	337.2	314.5	288.5
MARCH LOW SCENARIO	334.5	257.4	218.0
Change from September	-2.7	-57.1	-70.5
MARCH MID SCENARIO	334.5	296.4	227.0
Change from September	-2.7	-18.1	-61.5
MARCH HIGH SCENARIO	334.5	313.4	295.0
Change from September	-2.7	-1.1	6.5

*Investment earnings constitute the major source of revisions
 (see attached Table III for detail summary)

TOTAL GENERAL FUND UNRESTRICTED REVENUES

	<u>FY 1988</u>	<u>FY 1989</u>	<u>FY 1990</u>
SEPTEMBER MEAN ESTIMATE	2065.3	1990.6	2127.7
MARCH LOW SCENARIO	2085.1	1337.6	1285.1
Change from September	19.8	-653.0	-842.6
MARCH MID SCENARIO	2111.9	1772.5	1825.9
Change from September	46.6	-218.1	-301.8
MARCH HIGH SCENARIO	2156.4	2316.8	2424.9
Change from September	91.1	326.2	297.2

FIGURE I
GENERAL FUND UNRESTRICTED REVENUES
 (FORECAST COMPARISON)



FY 87 Actual

Actual 1.7994 billion

FY 88 Estimates

Low Case 2.0851 billion

Mid Case 2.1119 billion

High Case 2.1564 billion

FY 89 Estimates

Low Case 1.3376 billion

Mid Case 1.7725 billion

High Case 2.3168 billion

FY 90 Estimates

Low Case 1.2851 billion

Mid Case 1.8259 billion

High Case 2.4249 billion

TABLE II
Key Assumptions for March 1988
Petroleum Revenue Projections
For FY 1988 - FY 1990

ANS West Coast Crude Oil Price (\$/bbl at Los Angeles, Calif.)

	<u>Low</u>	<u>Mid</u>	<u>High</u>
FY 88	14.38	14.82	15.42
FY 89	10.92	14.17	18.13
FY 90	10.77	14.95	19.11

ANS Gulf Coast Crude Oil Price (\$/bbl at Houston, Texas)

	<u>Low</u>	<u>Mid</u>	<u>High</u>
FY 88	15.42	15.86	16.46
FY 89	11.93	15.19	19.15
FY 90	11.78	15.96	20.14

Weighted Average ANS Crude Oil Price (\$/bbl)

	<u>Low</u>	<u>Mid</u>	<u>High</u>
FY 88	14.80	15.24	15.84
FY 89	11.32	14.58	18.54
FY 90	11.16	15.34	19.51

Percent of ANS to Gulf Coast

	<u>Low</u>	<u>Mid</u>	<u>High</u>
FY 88	40	40	40
FY 89	40	40	40
FY 90	39	39	39

Taps Tariff (\$/bbl)

	<u>Low</u>	<u>Mid</u>	<u>High</u>
FY 88	3.61	3.61	3.61
FY 89	3.04	3.04	3.04
FY 90	2.46	2.46	2.47

Wellhead Value (\$/bbl)

Production Volume (mmbbs/day)*

	<u>Low</u>	<u>Mid</u>	<u>High</u>	<u>Low</u>	<u>Mid</u>	<u>High</u>
FY 88	9.47	9.77	9.99	1.995	1.995	1.995
FY 89	6.12	9.05	12.68	2.032	2.032	2.032
FY 90	6.60	10.48	14.34	1.979	1.979	1.979

*Actual volume has averaged 1.976 for first six months of FY 88

Inflation (%)

	<u>Low</u>	<u>Mid</u>	<u>High</u>
FY 88	2.80	3.15	3.41
FY 89	3.04	3.81	4.74
FY 90	3.15	4.05	5.25

TABLE III

DETAIL SUMMARY OF MARCH 1988 REVENUE PROJECTIONS

PETROLEUM

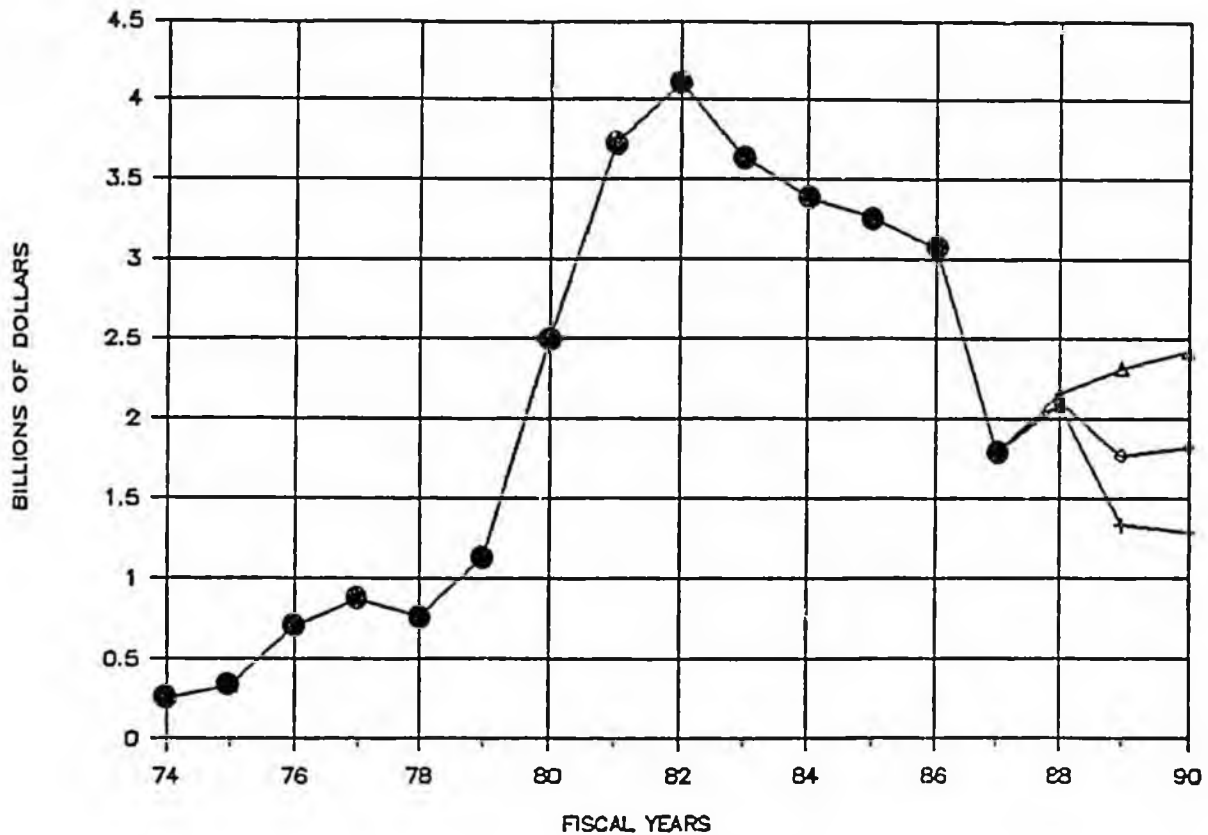
	FY 1987	FY 1988			FY 1989			FY 1990		
	ACTUAL	LOW	MID	HIGH	LOW	MID	HIGH	LOW	MID	HIGH
CORPORATE-PETROLEUM	120.4	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
SEVERANCE TAX	648.5	732.3	744.2	766.7	449.0	658.7	927.9	439.0	701.5	964.9
ROYALTIES	439.3	621.8	636.7	658.7	409.0	595.2	853.3	410.0	679.3	946.9
PROPERTY TAX	102.5	96.7	96.7	96.7	90.1	90.1	90.1	86.0	86.0	86.0
BONUS SALES	0.5	5.5	5.5	5.5	0.0	0.0	0.0	0.0	0.0	0.0
RENTS	3.8	4.1	4.1	4.1	4.3	4.3	4.3	4.3	4.3	4.3
INTERGOVERNMENTAL	9.0	8.3	8.3	8.3	7.8	7.8	7.8	7.8	7.8	7.8
SPECIAL SETTLEMENTS	70.5	161.9	161.9	161.9	0.0	0.0	0.0	0.0	0.0	0.0
SUB-TOTAL	1394.5	1750.6	1777.4	1821.9	1080.2	1476.1	2003.4	1067.1	1598.9	2129.9
% PETROLEUM	77.50%	83.96%	84.16%	84.49%	80.76%	83.28%	86.47%	83.04%	87.57%	87.83%

NON-PETROLEUM

	FY 1987	FY 1988			FY 1989			FY 1990		
	ACTUAL	LOW	MID	HIGH	LOW	MID	HIGH	LOW	MID	HIGH
TAXES	132.8	113.5	113.5	113.5	116.8	116.8	116.8	119.5	119.5	119.5
LICENSES & PERMITS	29.2	27.5	27.5	27.5	26.5	26.5	26.5	26.5	26.5	26.5
INTERGOVERNMENTAL	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
INVESTMENT EARNINGS	161.9	125.0	125.0	125.0	44.0	83.0	100.0	0.0	9.0	77.0
STATE RESOURCES	63.4	52.8	52.8	52.8	54.4	54.4	54.4	56.3	56.3	56.3
MISCELLANEOUS	16.9	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
SUB-TOTAL	404.9	334.5	334.5	334.5	257.4	296.4	313.4	218.0	227.0	295.0
TOTAL	1799.4	2085.1	2111.9	2156.4	1337.6	1772.5	2316.8	1285.1	1825.9	2424.9
MENTAL HEALTH TRUST		0.0	0.0	0.0	66.9	88.6	115.8	64.3	91.3	121.2

FIGURE II
GENERAL FUND UNRESTRICTED REVENUES
 (HISTORICAL VS. PROJECTIONS)

- HISTORICAL ACTUALS
- △ HIGH CASE SCENARIO
- ◇ MIDDLE CASE SCENARIO
- + LOW CASE SCENARIO



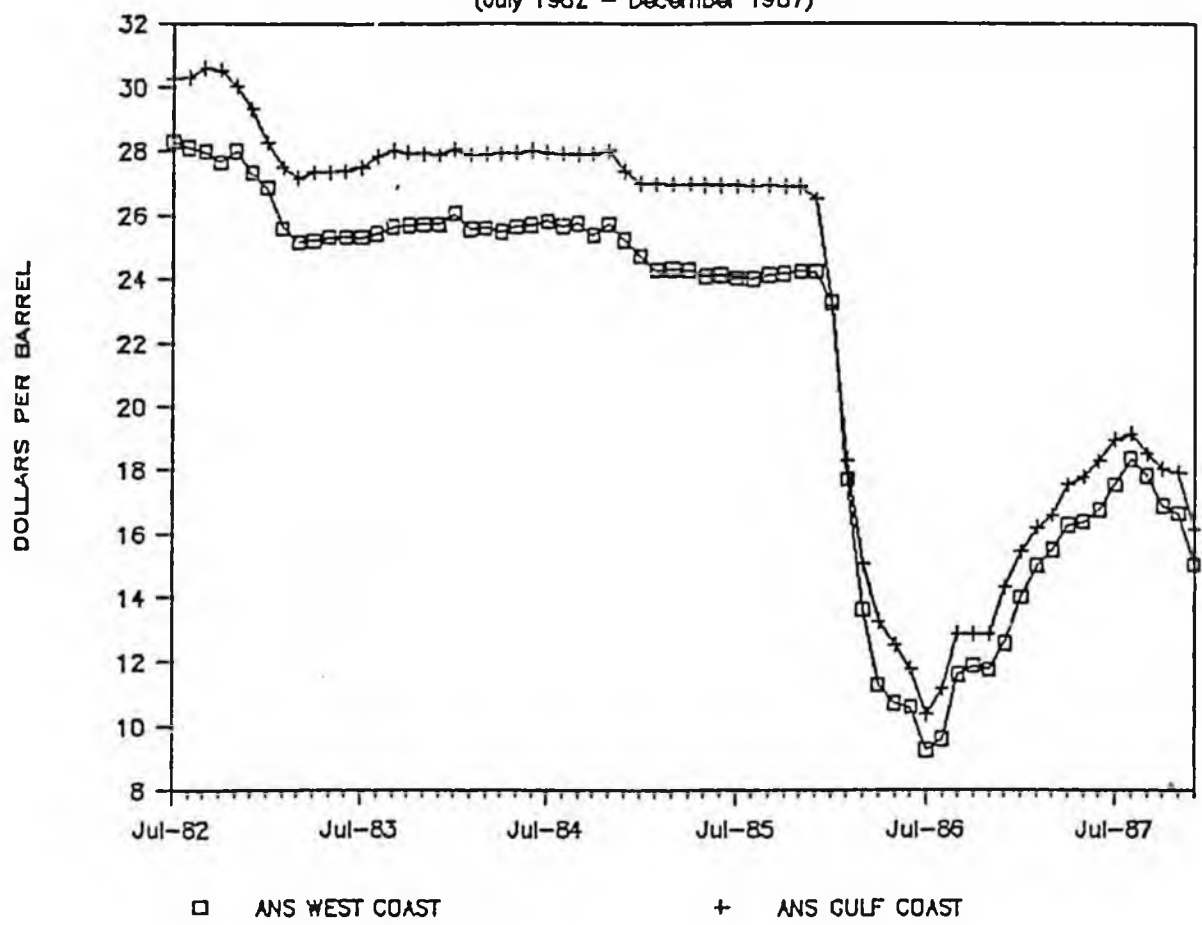
Revenue Actuals
(Nominal \$)

FY 73	.2082 billion
FY 74	.2549 billion
FY 75	.3334 billion
FY 76	.7098 billion
FY 77	.8743 billion
FY 78	.7649 billion
FY 79	1.1330 billion
FY 80	2.5012 billion
FY 81	3.7182 billion
FY 82	4.1084 billion
FY 83	3.6310 billion
FY 84	3.3901 billion
FY 85	3.2600 billion
FY 86	3.0755 billion
FY 87	1.7994 billion

Revenue Estimates
(Nominal \$)

<u>Low Case</u>	
FY 88	2.0851 billion
FY 89	1.3376 billion
FY 90	1.2851 billion
<u>Mid Case</u>	
FY 88	2.1119 billion
FY 89	1.7725 billion
FY 90	1.8259 billion
<u>High Case</u>	
FY 88	2.1564 billion
FY 89	2.3168 billion
FY 90	2.4249 billion

FIGURE III
HISTORICAL ANS CRUDE PRICES
(July 1982 - December 1987)



MEMORANDUM

State of Alaska

TO: Hugh Malone, Commissioner
Department of Revenue

DATE: March 23, 1988

FILE NO: 4112Y

TELEPHONE NO:

THRU: William Floerchinger, Director
Oil and Gas Audit Division

SUBJECT: Preliminary Steps to
Implement the Gault Report

FROM: Charles Logsdon, Petroleum Economist
Oil and Gas Audit Division

1. The most visible change in the forecast is the adoption of an unweighted three scenario approach rather than the development of a mean/variance probability approach to projecting oil revenues. We have retained, for the present, both approaches and will be looking for feedback from the forecast users.

2. The development of the scenarios by the price group (formerly called the Delphi group) will explicitly develop supply and demand projections for world crude oil markets. At this time, we will retain the group and use a Delphi method of price formation. Given a larger budget, a prestigious international consulting firm could be retained to augment this effort. At a minimum, subscriptions to trade and international data sources, which have been dropped in recent years due to budget reductions, need to be renewed.

3. The forecast should be done quarterly with specific deadlines of April 1, July 1, October 1, and January 1 (December 15 for preliminary to Governor). It is proposed that we also prepare a monthly summary which would revise the quarterly forecast to account for new information such as actual revenue collections or errors discovered after the forecast date.

4. The Saudi-Medium marker is retained for now for the following reasons although Saudi-Light would be a reasonable substitute.

a) Over time, the spot price of this crude has one of the highest statistical correlations with ANS prices as reported by Alaska producers.

b) Over time, the product yield for both topping and cracking refineries at the U.S. Gulf, as tracked by Platt's Oilgram, has one of the highest statistical correlations with ANS product yields.

c) Because the values of these two crudes tend to be quite close as measured both in terms of spot price and product yield, this tends to minimize the absolute error in determining the price differential between the two crudes.

Memorandum to Hugh Malone
March 23, 1988
Page 2

d) The behavior of Saudi Arabia is one of the most important, if not the most important, determinant of oil prices. Therefore, it is desirable to use a Saudi crude as marker particularly a sour crude which approximates ANS in quality.

5. We are in the process of coordinating more formally with both the Oil and Gas Conservation Commission and the Department of Natural Resources in developing assumptions about future production and well numbers.

CCL:pjt


MAR 15 1988

State of Alaska
Department of Revenue OFFICE OF THE COMMISSIONER
Oil and Gas Audit Division

M E M O R A N D U M

TO: Hugh Malone
Commissioner, Department of Revenue

THROUGH: William Floerchinger
Director, Oil and Gas Audit Division

FROM: Roger Marks 
Petroleum Economist

DATE: March 1, 1988

SUBJECT: Effect of TAPS Field Allocations on Revenues

The recent operation of TAPS at capacity, coupled with surges in production of the non-Prudhoe Bay fields on the North Slope, has raised concern regarding the State revenue implications of utilizing Prudhoe Bay as the "swing" producer to accommodate the other fields.

To examine these effects we disaggregated production from the four producing fields (Prudhoe Bay, Kuparuk, Lisburne, and Endicott) into 10,000 barrel per day "chunks." That way we could take a set volume (the chunk) from Prudhoe and allocate it to another field to see the overall revenue effect while keeping total North Slope production constant at the TAPS limit. This gives a per chunk effect that can be converted to any total amount desired. (For instance, a 100,000 barrel per day re-allocation would have roughly ten-times the effect of a one [10,000 barrel per day] chunk re-allocation.)

For the base case we used our current production assumptions. Under those assumptions Prudhoe Bay begins to decline after FY89 (mid-calendar 1990). Thus TAPS space should not be a problem after FY90. Therefore, we modelled five 10,000 barrel per day chunks (50,000 barrels per day) removed from Prudhoe Bay for the three years FY88-FY90, and added back 150,000 barrels per day in FY91. Similarly, for the other fields (one field at a time), we added five 10,000 barrel per day chunks for the same three years and removed 150,000 barrels per day in FY91. We kept price constant at \$10/bbl at the Prudhoe Bay wellhead.

The results are illustrated in Tables 1-4, which examine a re-allocation of 50,000 barrels per day from Prudhoe Bay to Kuparuk for the years FY88-FY90, with 150,000 barrels per day removed from Kuparuk and added back to Prudhoe Bay in FY91.

Tables 1 and 2 show the base cases for Prudhoe Bay and Kuparuk. Total severance taxes over the four years for both fields are \$2449 million, total royalties are \$2980 million, total undiscounted revenues are \$5430 million, and total discounted revenues (at eight percent) are \$4880 million.

Table 3 shows the impact on Prudhoe Bay of re-allocating five chunks to Kuparuk. Note that since the ELF is volume sensitive only the total severance taxes collected over the four years will be sensitive to the per year volumes. The total royalties will be unaffected as long as the total volume is constant. (Of course, the present value of both royalties and severance taxes will be affected by the time frame of their flows.) There is no appreciable change in the total severance tax over the four years. Given the large size of Prudhoe Bay, 50,000 barrels is relatively small, and the effect on the overall ELF and the per barrel severance tax is miniscule. Thus total revenue is unchanged and discounted revenues fall \$19 million.

Table 4 shows the impact on Kuparuk. Given the relative increased magnitude of the 50,000 barrels on the smaller field, the ELF and per barrel severance tax increase more than they decrease at Prudhoe Bay for the first three years, applied to the same number of barrels. For the final year the ELF and per barrel severance tax decrease more, but since they apply to less barrels the net effect is an increase in the Kuparuk severance tax of \$25 million from \$201 to \$226 million. Again, royalties are unchanged. Total undiscounted revenue is increased \$25 million, and discounted revenues increase \$36 million. The overall net effect to the State is an increase of undiscounted revenues of \$25 million, and an increase of discounted revenues of \$17 million.

Re-allocation to other fields would yield similar results. Thus it appears this practice may not be hurting the State.

year	psi price	10000 barrel per day chunks	volume	wells	elf	per bbl			total rev	disc rev
						sev tax	sev tax	royalty		
1988	10.00	156	569.4	631	0.820	613	1.00	662	1275	1275
1989	10.00	155	565.75	715	0.796	591	1.04	658	1249	1156
1990	10.00	150	547.5	803	0.765	549	1.00	636	1186	1017
1991	10.00	142	518.3	888	0.727	495	0.95	603	1097	872
						2248		2599	4807	4319

table 2
kuparuk - base case

year	psi price	10000 barrel per day chunks	volume	wells	elf	per bbl			total rev	disc rev
						sev tax	sev tax	royalty		
1988	10.00	28	102.2	315	0.532	65	0.63	110	175	175
1989	10.00	27	98.55	366	0.449	53	0.53	106	159	147
1990	10.00	27	98.55	396	0.411	48	0.45	106	154	132
1991	10.00	25	91.25	426	0.334	36	0.40	98	135	107
						201		421	623	561

table 3
prudhoe bay - 5 chunks

year	psi price	10000 barrel per day chunks	volume	wells	elf	per bbl			total rev	disc rev
						sev tax	sev tax	royalty		
1988	10.00	151	551.15	631	0.814	589	1.07	641	1230	1230
1989	10.00	150	547.5	715	0.789	567	1.04	636	1204	1114
1990	10.00	145	529.25	803	0.757	526	0.99	615	1141	978
1991	10.00	157	573.05	888	0.752	566	0.99	666	1232	978
						2248		2559	4806	4300

table 4
kuparuk - 5 chunks

year	psi price	10000 barrel per day chunks	volume	wells	elf	per bbl			total rev	disc rev
						sev tax	sev tax	royalty		
1988	10.00	33	120.45	315	0.596	85	0.71	130	219	215
1989	10.00	32	115.8	366	0.525	73	0.62	126	199	184
1990	10.00	32	116.8	396	0.491	68	0.56	126	194	166
1991	10.00	10	36.5	426	0.000	0	0.00	39	39	31
						226		421	640	597

Alaska State Legislature

INTERIM OFFICE
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ANCHORAGE, ALASKA 99503
(907) 561-7614

IN SESSION:
POUCH V
JUNEAU, ALASKA 99811
(907) 465-4714



Senator Mitch Abood
CHAIRMAN

Senate Committee on State Affairs

March 24, 1988

MEMORANDUM

TO: All Members of the Alaska Legislature

FROM: Senator Mitch Abood, Chairman
Senate Committee on State Affairs *M.A.*

SUBJECT: CS for House Bill 164, the so-called ELF bill

Attached you will find "The Truth About ELF," which I am providing to you for your information.

It is important to keep in mind that Petroleum revenue accounts for approximately 85% of all state revenue, and that the State of Alaska spends more than any other state on a per capita basis. In addition, between 1980 and 1986 the oil industry paid the state \$26 billion in taxes and royalties.

The ELF is working just as it was originally intended: it is creating jobs for Alaskans. It is stimulating economic activity in Alaska. It is providing an incentive for development of fields with higher development costs. It is increasing recoverable oil reserves.

The solution to Alaska's economic problems is not increasing taxes to fuel more government spending, as proposed by the Democratic Majority in the House of Representatives and the Governor. Instead, we should provide positive incentives for the further development of our private sector.

The Truth About ELF

- ✓ In 1977 the Legislature removed the stair-step production tax schedule and instituted a 12.25% (changed to 15% in 1981) tax rate on all oil production (in addition to the 12.5% royalty on all state leases). Since this tax burden would have shortened the economic life of all oil fields, the Economic Limit Factor (ELF) was developed to reduce the tax rate as fields approached their economic limits.
- ✓ From the beginning, the ELF applied to all fields in Alaska -- including Prudhoe Bay.
- ✓ During the period 1980 - 1986 the oil industry paid the State of Alaska \$26 billion in taxes and royalties.
- ✓ Oil revenue accounts for 85% of all revenue to the State of Alaska.
- ✓ Alaska's severance tax rate of 15% is the highest in the nation. This is a result of 11 oil and gas tax increases enacted since 1967.
- ✓ ELF reduces the 15% tax rate as fields mature and become more expensive to develop and operate.
- ✓ The absence of an ELF application to the marginal projects of the Prudhoe Bay Field could reduce the ultimate recovery factor for the reservoir.
- ✓ Even with the application of the ELF, the effective severance tax rate for Prudhoe Bay is the second highest in the United States.
- ✓ The tax impacts of the ELF are largely offset by increased royalty revenues to the state which result from higher current production.
- ✓ The ELF was designed as an incentive for producers to allow full and optimal developmental programs, and it has been extremely effective in pushing back production decline at Prudhoe Bay.
- ✓ The vast majority of the current \$400 million drilling program is being spent in Alaska. Each of the 8 rigs at Prudhoe, Kuparuk, and Endicott directly employs over 100 Alaskans, with over 200 more indirect jobs in support industries.

Alaska State Legislature

MAR 23 1988

INTERIM OFFICE
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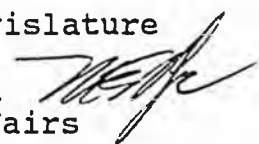
Senator Mitch Abood
CHAIRMAN

Senate Committee on State Affairs

March 23, 1988

MEMORANDUM

TO: All Members of the Alaska Legislature

FROM: Senator Mitch Abood, Chairman 
Senate Committee on State Affairs

SUBJECT: C3 for House Bill 164, the so-called ELF bill

Attached is a press release issued when Governor Hammond signed legislation in 1981 which related to the state's oil and gas taxation system, and the Economic Limit Factor (ELF). As stated in the press release, one of his conditions for signing the bill was that it "maintain the state's combined royalty and tax 'share'" at above 30 percent.

The key question then is what is the State of Alaska's current "share?" The following numbers are from "Petroleum Intelligence Weekly" (an independent publication), and they directly speak to Governor Hammond's point:

<u>Year</u>	<u>State of Alaska's Revenue Share</u>
1985	33.0%
1st half of 1986	41.8%
2nd half of 1986	63.7%
1st half of 1987	39.0%
2nd half of 1987	35.5%
1988 (through 2/1)	36.3%

Thus, the State government has been receiving far greater than a 30 percent share. You may then ask "well, but what about the future?"

Our own Department of Revenue has forecast that the State will receive far in excess of the 30 percent share Governor Hammond spoke of in the future, and here are the numbers they have forecast:

FY	State's share <u>\$13-14 market price</u>	State's share <u>\$15-16 market price</u>
88	79%	57%
89	92%	61%
90	96%	63%
91	103%	67%

Holy cats, all but one of their forecast shares are more than twice the 30 percent share Governor Hammond and legislative leaders had as an "essential condition." (Source: Department of Revenue: Larson, Logsdon, and Marks; Sensitivity Analysis of Projected Revenue Collections", December 1986, pages 82 and 93)

The ELF is working just as it was originally intended: it is creating jobs for Alaskans. It is stimulating economic activity in Alaska. It is providing an incentive for development of fields with higher development costs. It is increasing recoverable oil reserves.

The solution to Alaska's economic problems is not increasing taxes to fuel more government spending, as proposed by the Democratic Majority in the House of Representatives and the Governor. Instead, we should provide positive incentives for the further development of our private sector.

SB 158, HB 104

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU
JAY S. HAMMOND
GOVERNOR

NEWS RELEASE



FOR IMMEDIATE RELEASE
Date: _____
Time: _____
Place: _____
By: _____
Title: _____

HAMMOND SIGNS OIL & GAS LEGISLATION
7-27-81
6131

ALASKA HISTORICAL LIBRARY

FOR IMMEDIATE RELEASE

JUNEAU—Alaska Governor Jay Hammond late today signed into law a bill making major changes in the state's oil and gas taxing system, modifying the oil and gas taxing structure which has been in place for the past three years.

Hammond late Monday signed the oil and gas bill, PCCSSB 524, which besides amending the state's oil and gas laws provides corporate tax relief for most small businesses in the state.

Hammond said he signed the bill since it meets two essential conditions that he laid down in a letter to the Legislature June 23-- that any new oil and gas taxing bill must improve the state's case against a challenge by the oil industry over the state's taxing policies, and that the bill will maintain the state's combined royalty and tax "share" from its one-time resource at above 30 percent.

Hammond while saying the bill was not his first preference and is not perfect, said the bill meets his two major conditions.

MORE

Add 1-1-1-1

"It is the view of all pertinent state agencies that we should content ourselves with the present bill since a far worse alternative would be to take no action at all," Hammond said.

The Governor said the bill improves the state's legal posture in relation to a suit filed by the oil companies over the constitutionality of the 1978 state Oil and Gas Corporation Income tax in several ways.

--The bill adopts a series of amendments to ongoing state tax law designed to make the state's oil taxing policy, taken as a whole, look less unfair toward the oil industry. The amendments, designed to remove the "warts" from state tax law, amend state policy on depreciation, tax exemptions and a host of other issues.

--The bill provides for the deduction of the federal windfall profits tax from state tax payments. The windfall profits tax at the federal level had not been proposed when the state passed the oil and gas income tax in 1978, but the state's failure to permit a deduction for the federal tax has been considered a significant unfairness in the state's tax law.

--The bill makes additional technical changes to ensure that state Native corporations are afforded equal treatment under the income tax laws, regardless of whether they fall under the oil and gas income tax or the "ordinary" income tax, being reimplemented by the new tax law.

--And the bill allows the state to concentrate on the defense of the most questionable provision of the 1978 law, its reliance on "separate accounting" rather than income "apportionment," knowing the state will be returning to the apportionment formula to compute taxes starting on Jan. 1, 1982--limiting the state's tax liability under the existing law to just three years.

MORE

72
7501
43
74

The state in 1978 switched to requiring multinational oil companies to figure their state taxes on the basis of income they received worldwide based on the oil they extracted from the state. The law required the companies to use "separate accounting" in figuring their taxable income, rather than the traditional system of apportioning parts of their income earned from Alaska operations.

The companies sued arguing that the separating accounting system caused them to be taxed twice on their income, once in Alaska, and again in other states.

The state in the new tax law will be returning to a modified apportionment taxing formula, raising the state's severance tax to 15 percent from 12.25 percent to make up most of the revenue the abandonment of the old corporate oil and gas tax will cost the state.

While the apportionment approach to state taxation has been repeatedly upheld as constitutional by the Supreme Court, the court has yet to rule on a case where it was advocated by a taxing state, and has ruled twice against its use in cases brought by taxpayers.

"In short, the income tax in the future will incorporate a 'tried and true' approach to multistate taxation, whereas the present, separate-accounting approach does not," Hammond said.

He noted that several recent independent studies have questioned whether the new tax will cost the state more revenue than official state estimates. He said the latest official estimates by the state's Department of Revenue indicated the state between now and Fiscal Year 1985 will retain 31.2 percent of state oil income, compared to the current 31.8 percent.

Hammond said he has been assured that even if less favorable estimates were to prove correct, the bill will still retain the state 30.7 percent, meeting his bottomline requirement of a minimum of 30 percent.

MORE

"As for the possible revenue effects in 1981 and beyond, I have full confidence in the ability of the Legislature to deal at that time with whatever is required to retain the state's 'fair share' of our oil wealth," Hammond said.

He added he still intends this coming session to seek voter support for a policy statement that would support the state not letting its share of oil revenues fall below 30 percent. "It is incumbent upon all of us in public office to determine as clearly as possible what the electorate believes that 'fair share' to be," Hammond said.

He mentioned that the bill also substitutes a progressive tax table for the existing flat 5.4 percent corporate income tax—a tax which also contains a 4 percent surtax on taxable income over \$50,000. Under the new bill smaller corporations will pay 3 percent on their first \$10,000 of taxable income, 2 percent on their second \$10,000 and so on.

Hammond said the bill should result in a significant tax savings, especially for so called "Mom and Pop" family businesses in the state. The new bill also makes other modifications in the corporate tax law for 1981.

Hammond said the bill may need some modification next year, notably to clear up confusion over how the bill impacts the municipal revenue sharing formula—a formula formerly tied to the level of income from the oil and gas corporate income tax. He said he hopes that issue will be re-examined next session.

Statement of Governor Newsom on Signing RCSSB 524

I have today signed the Free Conference Committee Substitute for Senate Bill No. 524, the oil tax bill. I do so only after being reassured by the Departments of Law and Revenue that this legislation satisfies the two essential conditions that I set out in my letter to the Legislature last June 21st -- namely, that it will improve our case in the lawsuits over the oil and gas corporate income tax and that it will maintain the State's combined royalty and tax "share" in this one-time resource above 30 percent.

The Attorney General advises that several provisions in the bill will improve the State's legal posture.

- o First, it adopts the so-called "writs" amendments which I originally proposed in House Bill 192. These will eliminate a number of side issues in the litigation that could otherwise divert the court's attention from the basic issue in the case, which is whether states may use the "separate accounting" approach in taxing the income of multistate and multinational corporations.
- o Second, the Bill provides for the deduction of windfall profit tax payments. The windfall profit tax had not even been thought of when the present tax was passed in 1972, and it is generally recog-

nized that the failure to allow the deduction was an unintended, but significant unfairness in our income tax laws.

- o Third, the bill makes additional technical changes to ensure that Native corporations are afforded equal treatment under the income tax laws, regardless of whether they fall under the oil and gas income tax or the "ordinary" income tax.
 - o And fourth, oil and gas corporate taxpayers will start next year to pay income tax to the state under a modified apportionment approach. It is important to remember that the United States Supreme Court in recent years has repeatedly upheld the apportionment approach as a means for states to tax the income of multistate businesses. In stark contrast to this is the fact that separate accounting has yet to be ruled on in a case where it was advocated by the taxing state, and it has been rejected by the Court twice last year when it was advocated by taxpayers. In other words, the income tax in the future will incorporate a "trial and true" approach to multistate taxation, whereas the present, separate-accounting approach does not.
- Additionally, I am advised by the Department of

First: besides dealing with oil and gas taxes, this bill will provide significant tax relief for smaller corporations. Beginning this year, their tax rate will be one percent on their first \$10,000 of taxable income, two percent on their second \$10,000, and so on. For the many "mom and pop" enterprises that have incorporated themselves over the years, this is major relief from the present 5.1 percent rate on the first \$50,000 and 9.4 percent on any excess. Signing the bill now allows them to begin enjoying those benefits immediately, instead of waiting until the next session of the Legislature to see if something similar can be passed again.

Second, at present certain municipal revenue sharing refers to the total amount of income tax collected as the basis for the amount of revenue shared. Since this bill will reduce the actual income tax receipts (transferring much of the reduction over to the production tax), the formula for continued revenue sharing should be re-examined next year.

Revenue that the State's "share" during the period from FY 82 to FY 85 will be 31.2 percent. Some have objected to Revenue's estimate of the revenue effects of this bill and assert that the revenue consequences during that time will be as much as three or four times greater. However, even if the revenue effect should prove to be as great as those people fear, Alaska's "share" I'm advised will remain 30.7 percent -- thus still fulfilling my pronounced 30-percent requirement to avoid veto. As for possible revenue effects in 1981 and beyond, I have full confidence in the ability of the Legislature to deal at that time with whatever is required to retain the state's "fair share" of the oil wealth. Meanwhile, it is incumbent upon all the public officers to determine as clearly as possible what the electorate believes that "fair share" to be.

Critics of this particular bill have argued that it was hastily drafted and ill-considered and that the "backstop" approach -- which, incidentally, I introduced -- would have been far preferable. I can sympathize: the bill is not perfect, nor is it my preferred choice. I would rather have seen the people get a chance to vote on the question of whether Alaska's "share" in its oil wealth is too great, and I fully intend to introduce legislation next year that will give them precisely this opportunity. In the meantime, it is the view of all pertinent state agencies that we should content ourselves with the present bill. Since a alternative would be to take no action at all,

In conclusion I wish to make two final points.

Analysis by "Petroleum Intelligence Weekly"
2/1/88

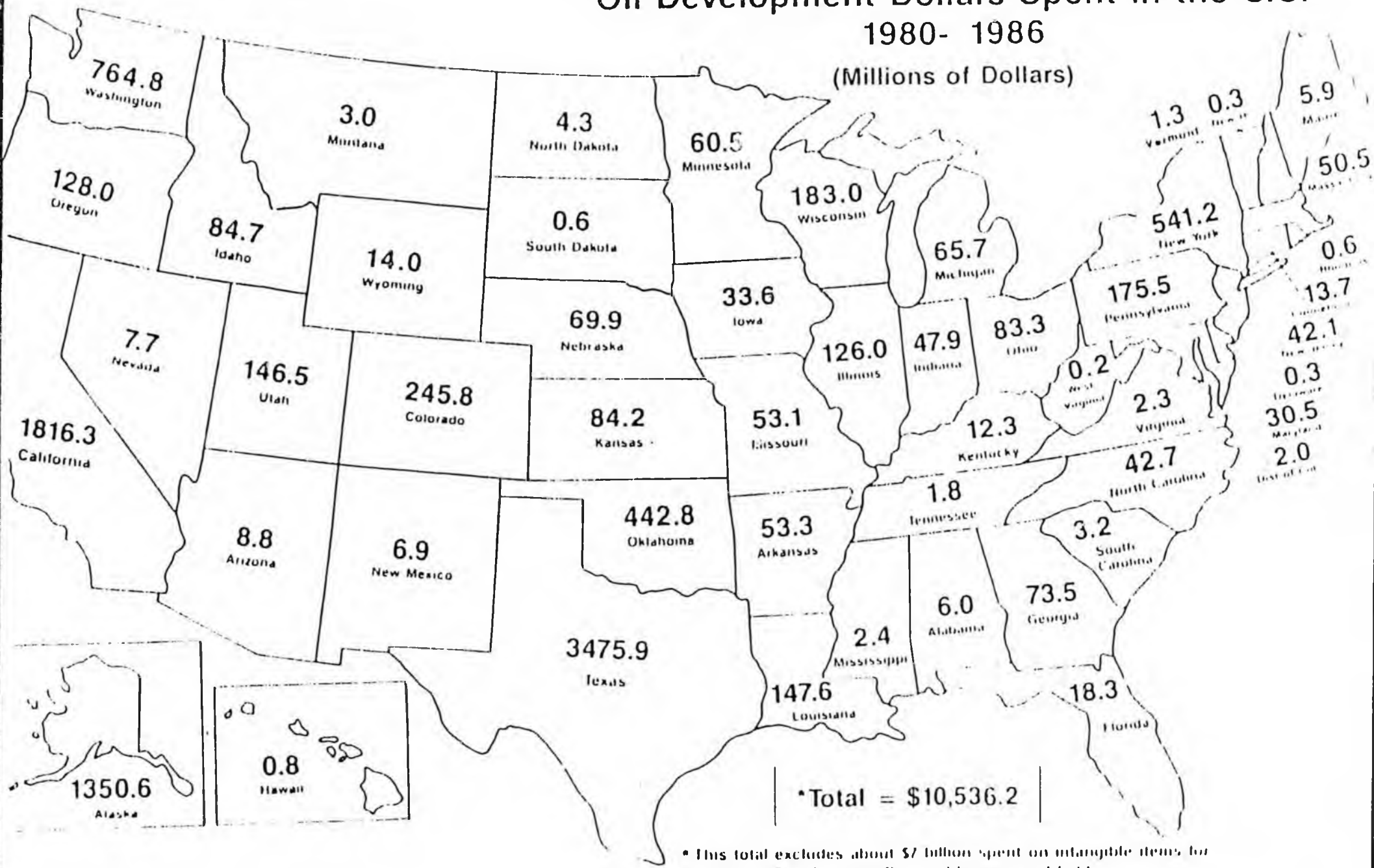
\$/bbl	Full Year 1985	1st Half 1986	2nd Half 1986	1st Half 1987	2nd Half 1987	Todate 1988
Avg West Coast Price	16.84	8.85	5.26	10.62	10.47	10.01
Producing Cost	0.90	0.75	0.75	0.85	0.85	0.85
Depreciation	1.53	2.17	2.17	2.25	2.25	2.25
Total Net Revenue	14.41	5.93	2.34	7.52	7.37	6.91
State Royalty	2.02	1.02	0.58	1.24	1.23	1.17
Severance	2.22	1.17	0.70	1.40	1.09	1.05
Property	0.21	0.18	0.18	0.15	0.15	0.15
State Income Tax	0.30	0.11	0.03	0.14	0.15	0.14
Total State	4.75	2.48	1.49	2.93	2.62	2.51
Federal Income Tax	4.58	1.64	0.41	1.61	1.67	1.54
Industry Profit (including TAPS)	7.26	2.45	1.09	3.51	3.62	3.29
State % of Net Revenue	33.0%	41.8%	63.7%	39.0%	35.5%	36.3%

ELF BULLETS

- As originally enacted in 1978, ELF was intended to give producers a break on severance taxes on low-production wells such as those in Cook Inlet. When Republicans took control of the House in the 1981 coup, they adopted the Senate Republicans' rewrite of the ELF law, which had the effect of allowing the tax break to be applied to Prudhoe Bay starting in 1987, well in advance of the "supergiant" field beginning its production decline.
- The House last year passed and sent to the Senate new legislation that would close the loophole allowing high-production fields to reap the tax-avoidance benefits of the ELF law. If the Senate does not approve the House bill, the State of Alaska will lose an estimated \$415 million over this fiscal year and the next, according to the Department of Revenue. The five-year loss, through FY 92, is estimated to total \$1.2 billion.
- The oil companies argue that changing the ELF now could cause them to cut some of the 2,400 jobs they claim the tax break has allowed them to bring to their North Slope operations, and they'd prefer the Legislature cut the state budget by \$400 million to cover the ELF loss. We know that nowhere near 2,400 North Slope jobs have been created, but even if that number were true, it's hardly likely the Alaska economy would receive the full benefit of those jobs, given the industry's history of hiring out-of-state residents to work on the Slope. Even more significantly, if we were to follow the industry's advice and cut another \$400 million from the state budget, the economy would lose more than 9,500 jobs -- jobs now held by Alaskans, not temporary workers who send their paychecks home to other states.
- The oil companies also argue that changing the ELF law to avoid the anticipated loss would disrupt their "stable tax climate." The implication that changing the ELF would represent an unfair tax burden on the industry or would somehow jeopardize profits simply is not supportable. The fact is the industry long ago recovered the initial capital costs from North Slope operations; after deducting all taxes, operating costs and even new investment costs, the companies as of 1986 had still managed to take approximately \$18.6 billion in net profits out of Alaska.

North Slope Alaska Oil Development Dollars Spent in the U.S. 1980- 1986

(Millions of Dollars)



*Total = \$10,536.2

* This total excludes about \$7 billion spent on intangible items for Kuparuk, East Prudhoe Bay, and Urethane oil fields

State of Alaska
MEMORANDUM

Office of the Governor

Division of Policy

P.O. Box AM, Juneau, AK, 99811

Tel. 465-3568 / Mail Stop 0164

TO: Mary Halloran
Director

DATE: 16 June 1987

FROM: Gregg Erickson *GKE*
Senior Economist

SUBJECT: Oil Industry Profits In Alaska

Professor Edward Deakin has completed his report on "Income and Investment Flows From Alaska Oil and Gas Producing Activities," prepared for Rep. John Sund and the legislature's Joint Tax Policy Committee. Deakin is Price Waterhouse Professor of Accounting at the University of Texas. This is the first time anyone outside the industry has documented in such detail the extraordinary profitability of the oil industry in Alaska.

As far as I am aware Rep. Sund has not yet decided when or in what forum to release the report. Some of the report's findings are highlighted below:

- In 1985 the industry in Alaska earned \$5.08 billion in profits (after all taxes, interest, depreciation and costs). In 1986, the year in which oil prices fell to historic lows, industry profits were \$3.45 billion [p. 4].
- In every year since 1978, profits removed from Alaska have exceeded investments in the state; in 1981 the industry's net investment position became positive. In 1985, \$4.54 billion was expatriated from Alaska, compared with \$0.57 billion reinvested [p. 8].
- Through 1986 the industry earned an after-tax rate of return of 16.9 percent on its Alaska investments. Through the year 2000 the after-tax rate is projected at 19.0 percent [p. 8].
- Using the average oil price assumptions underlying the June Dept. of Revenue forecast (\$10/barrel wellhead), Deakin forecasts the companies' 1988 profits from Alaska operations at \$3.92 billion [p. 37].

enclosures: 1) "Income and Investment Flows From Alaska Oil and Gas Producing Activities."
2) Deakin Vita.

cc: Representative J. Sund
Representative K. Brown
R. Fineburg
✓ J. Hartle

Three Oil Firms Report Lower Quarterly Profit

Standard's Decline Was 21%;
Net Fell 98% at Ashland,
20% at Atlantic Richfield

A WALL STREET JOURNAL News Roundup
Three U.S. oil companies posted earnings declines for the latest quarter, reflecting lower profit margins.

Earnings fell 21% at Standard Oil Co., 20% at Atlantic Richfield Co. and a whopping 98% at Ashland Oil Inc.

At Ashland and Arco, product prices failed to keep pace with rising crude oil prices while at Standard, the drop reflected lower Alaskan crude oil prices compared with a year ago.

Standard Oil Co.

Cleveland-based Standard posted a 14% decline in first-quarter revenue to \$2.49 billion from \$2.91 billion in 1986.

The company said Alaskan crude oil prices dropped 23.1% to an average price of \$15.51 a barrel during the quarter, compared with \$20.18 in the year-ago period.

The company gets 97% of its oil from Alaska.

Standard said first-quarter operating profit from exploration and production dropped 30% to \$327 million from \$464 million in 1986, while operating profit from refining and marketing—aided by lower crude oil costs—jumped sharply to \$72 million from \$5 million in the year-earlier quarter.

The company said that exploration expenses dropped 72% to \$43 million from \$152 million in 1986 because of lower dry-

	MARCH 31 QUARTER NET INCOME		1987		1986		% chg.
	in millions	per share	in millions	per share	in millions	per share	
Arco	\$239	1.31	\$259	1.64	-	-	- 20
Ashland	\$0.7	.02	\$41.6	1.20	-	-	- 98
Standard	\$200	.85	\$253	1.08	-	-	- 21

hole and support costs, and lower field geological and geophysical expenses, among

Separately, Standard disclosed that its directors have been discussing British Petroleum Co.'s proposed purchase of the company with BP representatives. The disclosure suggests that the stalemate over the takeover proposal may be easing, and it also raises the possibility that Standard may be able to extract a higher price from BP.

Standard said its directors haven't yet reached a decision on BP's tender offer of \$7.4 billion, or \$70 a share, for Standard's publicly held shares. The company said the seven members of its special committee, which consists of directors who are neither Standard officers nor affiliated with BP, met yesterday and will continue their discussions.

other reasons:

Robert B. Horton, chairman and chief executive officer, said that despite the lower first-quarter results, the company has "done well, even with the lower prices. Refining and marketing results improved, and the cost-cutting and restructuring we did last year is paying off."

As previously reported, Standard said the special committee would make a recommendation on the tender offer no later than yesterday. The company didn't elaborate on the postponement. BP already owns about 55% of Standard's common shares.

Standard said BP had extended the tender offer to 12:01 a.m. EDT May 5 from 12:01 a.m. next Wednesday.

In New York Stock Exchange composite trading yesterday, Standard closed at \$71, up 50 cents, on volume of 2.2 million shares.

Ashland Oil Inc.

The Ashland, Ky.-based company said higher crude oil prices and excess inventory contributed to an \$8.8 million operating loss in its second quarter ended

March 31.

Net income included a gain of \$9.5 million from the transfer of funds to an employee stock ownership plan.

The average number of common and common-equivalent shares outstanding increased to 32.1 million from 29.5 million in 1986.

Revenue dropped 11% to \$1.52 billion from \$1.71 billion in the 1986 quarter. Revenue excludes excise taxes.

Ashland, which had expected to report a decrease in earnings, said that it was hurt by the performance of its Ashland Petroleum Co. and SuperAmerica units. Ashland Petroleum posted an operating loss of \$34.6 million for the quarter, compared with operating profit of \$34.8 million in 1986. SuperAmerica, a chain of convenience and self-serve gasoline outlets, posted a \$51,000 operating loss during the quarter, compared with operating profit of \$17.5 million in the year-earlier period.

"While crude oil prices increased in line with OPEC policy, unseasonably warm weather and high product inventories throughout the industry kept product prices from increasing as rapidly," said John R. Hall, Ashland chairman and chief executive officer.

Ashland produces little crude. As a result, the company is hurt when prices for crude rise more rapidly than prices of gasoline and other refined products.

Mr. Hall nevertheless said that Ashland's profit margins are expected to pick up with the onset of the summer driving and road construction season.

Net income for the six months slid 70% to \$27.9 million, or 86 cents a share, from \$91.9 million, or \$2.68 a share, in the year-earlier six months. Revenue dropped 18% to \$3.02 billion from \$3.69 billion in the 1986 quarter.

Ashland shares closed yesterday at \$59.875, off \$1, in New York Stock Exchange composite trading.

Atlantic Richfield Co.

Los Angeles-based Arco said its profit decline resulted from lower margins that reflected the lag in the rise of product prices compared with crude-price in-

The Alaska producers are doing A-OK
(Standard + ARCO)

Am. Daily News
4/30/87

Texaco profit cut by 64%
NEW YORK — Texaco Inc. said Wednesday that slumping crude and product prices, and fallout from its multibillion-dollar legal battle with Pennzoil Co., helped cut its first-quarter profit by 64 percent from a year earlier. The White Plains, N.Y.-based oil company, the nation's third-largest after Exxon Corp. and Mobil Corp., said it earned \$118 million, or 49 cents a share, in the first three months of this year. That compared with a profit of \$328 million, or \$1.37 a share, in the first quarter of 1986. Sales totaled \$8.5 billion, vs. \$9.6 billion in the earlier period.

Standard - much higher profit
ARCO - higher profit

creases.

Revenue declined 13% to \$3.74 billion from \$4.29 billion.

But Lodwick M. Cool, chairman, said he was "extremely pleased" with the company's performance because it "demonstrates Arco's earning power in a lower crude-price environment."

Reductions in Arco's exploration and operating costs helped earnings in the latest period, Mr. Cool said. Exploration expenses totaled \$75 million in the quarter, down from \$137 million a year ago.

Arco shares closed yesterday at \$84.50, up 25 cents, in New York Stock Exchange composite trading.

POTENTIAL REVENUES
FY 1989 - FY 2000
 (UGF \$, Millions)

	<i>FY</i> 89	<i>FY</i> 90	<i>FY</i> 91	<i>FY</i> 92	<i>FY</i> 93	<i>FY</i> 94	<i>FY</i> 95	<i>FY</i> 96	<i>FY</i> 97	<i>FY</i> 98	<i>FY</i> 99	<i>FY</i> 2000
<u>POTENTIAL SOURCES</u>												
USE PF EARNINGS*:												
<i>Undistributed only</i>	533	407	299	209	104	0	0	0	0	0	0	0
<i>Dividends</i>	459	488	486	486	523	560	599	641	685	730	778	828
<i>Inflation proofing</i>	438	566	614	665	719	762	701	746	793	842	893	947
ADOPT INDIVIDUAL INCOME TAX	83	255	269	282	290	300	300	300	300	300	300	300
SEVERANCE TAX ELF REVISION	415**	280	272	249	217	200	185	160	142	136	124	144
RETURN TO SEPARATE ACCOUNTING	180	180	189	187	159	135	110	82	59	36	12	10
OIL & GAS PROPERTY TAX REVISION	160***	75	71	66	62	59	55	52	49	46	43	40
MOTOR FUEL TAX INCREASE	35	32	32	33	35	36	37	39	40	42	44	46

*Permanent Fund Corporation 1/31/88 projections. Amounts shown as available from components of Permanent Fund earnings assume no use of undistributed earnings or inflation proofing in prior years.

**FY 89 figure includes collections from two fiscal years: \$187 million in FY 88, and \$228 million in FY 89.

***FY 89 figure includes collections from two fiscal years: \$82 million due 6/88, and \$78 million due 6/89.

MAR 15 1988

State of Alaska
Department of Revenue OFFICE OF THE COMMISSIONER
Oil and Gas Audit Division

M E M O R A N D U M

TO: Hugh Malone
Commissioner, Department of Revenue

THROUGH: William Floerchinger
Director, Oil and Gas Audit Division

FROM: Roger Marks *RM*
Petroleum Economist

DATE: March 1, 1988

SUBJECT: Effect of TAPS Field Allocations on Revenues

The recent operation of TAPS at capacity, coupled with surges in production of the non-Prudhoe Bay fields on the North Slope, has raised concern regarding the State revenue implications of utilizing Prudhoe Bay as the "swing" producer to accommodate the other fields.

To examine these effects we disaggregated production from the four producing fields (Prudhoe Bay, Kuparuk, Lisburne, and Endicott) into 10,000 barrel per day "chunks." That way we could take a set volume (the chunk) from Prudhoe and allocate it to another field to see the overall revenue effect while keeping total North Slope production constant at the TAPS limit. This gives a per chunk effect that can be converted to any total amount desired. (For instance, a 100,000 barrel per day re-allocation would have roughly ten-times the effect of a one [10,000 barrel per day] chunk re-allocation.)

For the base case we used our current production assumptions. Under those assumptions Prudhoe Bay begins to decline after FY89 (mid-calendar 1990). Thus TAPS space should not be a problem after FY90. Therefore, we modelled five 10,000 barrel per day chunks (50,000 barrels per day) removed from Prudhoe Bay for the three years FY88-FY90, and added back 150,000 barrels per day in FY91. Similarly, for the other fields (one field at a time), we added five 10,000 barrel per day chunks for the same three years and removed 150,000 barrels per day in FY91. We kept price constant at \$10/bbl at the Prudhoe Bay wellhead.

The results are illustrated in Tables 1-4, which examine a re-allocation of 50,000 barrels per day from Prudhoe Bay to Kuparuk for the years FY88-FY90, with 150,000 barrels per day removed from Kuparuk and added back to Prudhoe Bay in FY91.

Tables 1 and 2 show the base cases for Prudhoe Bay and Kuparuk. Total severance taxes over the four years for both fields are \$2449 million, total royalties are \$2980 million, total undiscounted revenues are \$5436 million, and total discounted revenues (at eight percent) are \$4880 million.

Table 3 shows the impact on Prudhoe Bay of re-allocating five chunks to Kuparuk. Note that since the ELF is volume sensitive only the total severance taxes collected over the four years will be sensitive to the per year volumes. The total royalties will be unaffected as long as the total volume is constant. (Of course, the present value of both royalties and severance taxes will be affected by the time frame of their flows.) There is no appreciable change in the total severance tax over the four years. Given the large size of Prudhoe Bay, 50,000 barrels is relatively small, and the effect on the overall ELF and the per barrel severance tax is miniscule. Thus total revenue is unchanged and discounted revenues fall \$19 million.

Table 4 shows the impact on Kuparuk. Given the relative increased magnitude of the 50,000 barrels on the smaller field, the ELF and per barrel severance tax increase more than they decrease at Prudhoe Bay for the first three years, applied to the same number of barrels. For the final year the ELF and per barrel severance tax decrease more, but since they apply to less barrels the net effect is an increase in the Kuparuk severance tax of \$25 million from \$201 to \$226 million. Again, royalties are unchanged. Total undiscounted revenue is increased \$25 million, and discounted revenues increase \$36 million. The overall net effect to the State is an increase of undiscounted revenues of \$25 million, and an increase of discounted revenues of \$17 million.

Re-allocation to other fields would yield similar results. Thus it appears this practice may not be hurting the State.

year	oil price	barrel per day chunks	volume	wells	oil	per bbl			total rev	disc rev
						sev tax	sev tax	royalty		
1988	10.00	156	569.4	631	0.820	613	1.00	662	1275	1275
1989	10.00	155	565.75	715	0.796	591	1.04	658	1249	1156
1990	10.00	150	547.5	803	0.765	549	1.00	636	1196	1017
1991	10.00	142	518.3	888	0.727	495	0.95	603	1097	872
						2248		2559	4807	4319

table 2
kuparuk - base case

year	oil price	10000 barrel per day chunks	volume	wells	oil	per bbl			total rev	disc rev
						sev tax	sev tax	royalty		
1988	10.00	28	102.2	315	0.532	65	0.63	110	175	175
1989	10.00	27	98.55	366	0.449	53	0.53	106	159	147
1990	10.00	27	98.55	396	0.411	48	0.49	106	154	132
1991	10.00	25	91.25	426	0.334	36	0.40	98	125	107
						201		421	623	561

table 3
prudhoe bay - 5 chunks

year	oil price	10000 barrel per day chunks	volume	wells	oil	per bbl			total rev	disc rev
						sev tax	sev tax	royalty		
1988	10.00	151	551.15	631	0.814	589	1.07	641	1230	1230
1989	10.00	150	547.5	715	0.789	567	1.04	636	1204	1114
1990	10.00	145	529.25	803	0.757	526	0.99	615	1141	978
1991	10.00	157	573.05	888	0.752	566	0.99	666	1232	970
						2248		2559	4806	4300

table 4
kuparuk - 5 chunks

year	oil price	10000 barrel per day chunks	volume	wells	oil	per bbl			total rev	disc rev
						sev tax	sev tax	royalty		
1988	10.00	33	120.45	315	0.596	85	0.71	130	215	215
1989	10.00	32	116.8	366	0.525	73	0.62	126	199	184
1990	10.00	32	116.8	396	0.491	68	0.58	126	194	166
1991	10.00	10	36.5	426	0.000	0	0.00	39	39	31
						226		421	548	597

STATE OF ALASKA
1988 LEGISLATIVE SESSION

BILL VERSION: CSEB 164(Fin) am
PUBLISH DATE: _____

FISCAL NOTE

REQUEST: _____

Revision Date: March 4, 1988 Agency Affected: _____
Title: An Act Relating to the Oil and Gas Properties Production Tax and Effective Date BRU: _____
Sponsor: Rules/Governor Components: _____
Requestor: _____

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING						

CAPITAL	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93

REVENUE	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93
	187,410	227,630	280,260	272,570	248,510	216,540

FUNDING: (Thousands of Dollars)

GENERAL FUND	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93
FEDERAL FUNDS						
OTHER						
TOTAL						

POSITIONS:

FULL-TIME	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93
PART-TIME						
TEMPORARY						

ANALYSIS : (Attach a separate page if necessary)

(See Attached)

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

Approved by Commissioner: Hugh Malone W/FIR Date: 3/8/88
Agency: Revenue

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

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

The following tables illustrate both the revenue and tax rate impact of the bill by North Slope oil field.

Revenue Impact by North Slope Oil Field
(Millions Dollars)

Fiscal Year	Prudhoe	Kuparuk	Milne	Endicott	Lisburne	West Sak	Thonson	Seal	Hiakuk	North Slope
1988	133.57	59.56	0	0	-6.02	0	0	0	0	187.4
1989	161.97	72.11	0	0	-6.45	0	0	0	0	227.63
1990	201.28	88.54	0	-2.48	-7.18	0	0	0	0	280.26
1991	236.52	50.55	0	-2.54	-6.8	0	0	0	-5.16	272.57
1992	237.28	51.09	-11.78	-2.85	-8.98	0	-6.45	0	-9.8	248.51
1993	230	50.58	-29.72	-6.9	-8.37	0	-8.33	0	-10.72	216.54
1994	220.71	49.16	-30.2	-9.14	-9.22	0	-9.16	0	-12.27	199.88
1995	215.03	41.79	-33.15	-10.49	-10.02	0	-10.02	0	-7.92	185.22
1996	204.76	30.67	-33.88	-10.82	-11.1	0	-11	0	-8.68	159.95
1997	201.93	19.63	-34.84	-10.67	-11.72	0	-14.73	0	-8.11	141.55
1998	210.57	9.89	-35.72	-1.19	-12.35	0	-16.08	-12.39	-8.22	134.51
1999	210.3	3.88	-32.94	-6.64	-12.49	0	-17.3	-10.86	-9.69	124.26
2000	230.27	1.62	-36.84	-3.64	-12.91	0	-19.56	-5.78	-10.45	143.71
2001	232.8	.53	-32.78	-1.01	-14.48	0	-17.3	6.2	-8.77	152.69
2002	235.74	-.02	0	-.02	-15.66	0	-17.47	-6.72	-6.38	189.47
2003	339.18	-.09	0	-.03	-15.52	0	-14.75	-0.86	-25.03	274.9
2004	353.23	-.06	0	0	-15.64	0	-10.36	-9.31	-20.3	302.54
2005	347.35	-.08	0	0	-15.49	0	-6.58	-9.79	-18.94	296.47
Total Revenue										
Nominal	4210.92	534.93	-311.85	-68.42	-200.38	0	-178.09	-70.01	0	3917.1
10%	1759.01	350.66	-125.17	-31.41	-78.62	0	-60.13	-18.28	0	1796.06
8%	2041.51	378.38	-148.47	-36.32	-92.45	0	-73.46	-23.57	0	2045.62

Change in Tax rate

Year	Prodhoe	Kuparuk	Milne	Endicott	Lisburne	West Sak	Thonson	Seal	Niakuk
1988	.02487	.071445	0	0	-.03159275	0	0	0	0
1989	.02487	.071445	0	-.00346675	-.03198475	0	0	0	0
1990	.02487	.071445	0	-.001568	-.0276605	0	0	0	-.07216475
1991	.02487	.071445	0	-.00150675	-.02718275	0	0	0	-.0873915
1992	.02487	.071445	0	-.00885675	-.0230055	0	0	0	-.08975575
1993	.02487	.071445	0	-.018285	-.02766	0	-.0320215	0	-.0878325
1994	.02487	.071445	0	-.018285	-.02766	0	-.03193575	0	-.091483
1995	.02487	.071445	0	-.018285	-.02766	0	-.0318255	0	-.03736
1996	.02487	.071445	0	-.018285	-.02766	0	-.0317275	0	-.089595
1997	.02487	.071445	0	-.018285	-.02766	0	-.03095575	0	-.089565
1998	.02487	.071445	0	-.018285	-.02766	0	-.03717	0	-.089295
1999	.02487	.071445	0	-.018285	-.02766	0	-.050835	-.002009	-.08976
2000	.02487	.071445	0	-.018285	-.02766	0	-.059235	-.0023275	-.090225
2001	.02487	.071445	0	-.018285	-.02766	0	-.06369	-.00231525	.00063
2002	.02487	.071445	0	-.018285	-.02766	0	-.067425	-.00231525	0
2003	.02487	.071445	0	-.018285	-.02766	0	-.060735	-.00197225	0
2004	.02487	.071445	0	-.018285	-.02766	0	-.049425	-.002085	0
2005	.02487	.071445	0	-.018285	-.02766	0	0	0	0

REQUES:
Revision Date:
Title: An act relating to the oil and gas production tax.
Sponsor: Rules/Governor
Requestor: House Resources

Bill Version: CSB 164 (Fin)
Publish Date: HOUSE 3/30/87
Agency Affected: Revenue
BRU: Audit
Components: Oil & Gas

EXPENDITURES/REVENUES: (Millions of Dollars)

	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
OPERATING						
PERSONAL SERVICES	-	-	-	-	-	-
TRAVEL	-	-	-	-	-	-
CONTRACTUAL	-	-	-	-	-	-
SUPPLIES	-	-	-	-	-	-
EQUIPMENT	-	-	-	-	-	-
LANDS & STRUCTURES	-	-	-	-	-	-
GRANTS, CLAIMS	-	-	-	-	-	-
MISCELLANEOUS	-	-	-	-	-	-
TOTAL OPERATING	-	-	-	-	-	-
CAPITAL	-	-	-	-	-	-
REVENUE	-	88.7	108.5	117.6	112.9	117.8

FUNDING: (Thousands of Dollars)

GENERAL FUND	-	-	-	-	-	-
FEDERAL FUNDS	-	-	-	-	-	-
OTHER	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-

POSITIONS:

FULL-TIME	-	-	-	-	-	-
PART-TIME	-	-	-	-	-	-
TEMPORARY	-	-	-	-	-	-

ANALYSIS: The above numbers represent the increase in general fund revenues if this bill becomes law. The key assumptions are introduction of a 55,000,000 scaling factor into the exponent of the current ELF formula and fixing the value of the Production at the Economic Limit (PEL) at 300 barrels per well per day. The production impact from FY88 through FY2005 represents a cumulative total loss of 20.9 million barrels.

Prepared By: Chuck Logsdon
Division: Office of the Commissioner


Phone: 276-5364
Date: 3/19/87

Approved by Commissioner: [Signature]
Agency: Revenue

Date: 3/19/87

Distribution (by Agency preparing fiscal note)
Legislative Finance
Legislative Sponsor
Requestor
Office of Management and Budget
Impacted Agency(ies)
Senate Secretary

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ARCO PLANS TO SPEND MORE THAN \$7 BILLION IN ALASKA

ANCHORAGE, Ak., February 22 -- ARCO Alaska, Inc. is prepared to invest more than \$7 billion in Alaska over the next ten years, according to its President Bill Wade.

Of that total, more than \$3 billion will go to development of known reserves. Other opportunities include investment for ongoing operations in fields now in production in Alaska, and for exploration and development of new fields, if oil is found.

"To accomplish all of this will require reasonable oil prices and a stable tax policy," Wade told the Anchorage Chamber of Commerce Forum. He emphasized that as of now, "...these are plans. Our goal is to make them a reality."

Much remains to be done at Prudhoe and Kuparuk where over 1,000 additional wells should be drilled, Wade said. These wells will be drilled at a cost of \$2 billion to \$3 billion to field owners, he said.

At Prudhoe Bay, ARCO and its partners also are planning to install new gas handling equipment along with facilities to handle increased water production which comes as the field matures.

And at Kuparuk, 40 miles west of Prudhoe, ARCO is planning to install a small-scale Enhanced Oil Recovery Project. Those facilities are now under construction at Wasilla, near Anchorage. In the next ten years, this project could be expanded to cover the entire Kuparuk field.

Additional drill sites and wells have yet to be added to the new Lisburne field. Those investments will cost \$250 million.

"Another major expenditure included in our \$7 billion estimate is the initial development of the West Sak field," Wade said.

"We estimate that West Sak could contain up to 20 billion barrels of oil in place," he said. "But because the West Sak sands are shallow and contain heavier oil, this field is a technical challenge to produce.

"Given the right investment climate, we will find the way to produce West Sak," he said. The first phase of full field development at West Sak could cost over \$2 billion with development planned to begin in the early to mid-1990's.

Alaska is an area of high exploration potential, and Wade said ARCO intends to search vigorously for new sources of oil to replace current production.

The Coastal Plain of the Arctic National Wildlife Refuge is the area of greatest potential in North America, Wade declared.

"ARCO has committed substantial resources to opening ANWR, and if the effort is successful, then Alaska and the nation will benefit," Wade said.

A parallel issue in the ANWR debate is the issue of land exchanges between 18 Alaska native groups and the U.S. Department of the Interior.

The American people will gain nearly a million acres of inholdings in national wildlife refuges in Alaska, now owned by the native corporations. And in return, the natives will gain subsurface rights to 166,000 acres on the Coastal Plain.

The State of Alaska gains by the fact that exploration can occur several years sooner on native lands, Wade said, thereby stimulating jobs and economic activity within the state.

The land exchange issue will be decided by Congress after the opening of the Coastal Plain has been decided, he emphasized.

###

No decline expected by oil firms

Daily news staff and wire reports

Atlantic Richfield Co. said Tuesday that Prudhoe Bay oil production will remain at 1.5 million barrels a day through 1989, rather than beginning to decline in 1988 as previously thought.

Robert Wycoff, Arco president, also told shareholders at the company's annual meeting that if their projections of \$20-per-barrel oil were accurate for the next five years, the company will spend \$3 billion in the coming decade for further development of its North Slope holdings.

That spending level could yield another 800 million barrels of oil and gas reserves from the North Slope, he said.

Wycoff also urged shareholders to support opening the coastal plain of the Arctic National Wildlife Refuge for oil development. "It is important to the country's energy



Associated Press file photo

George M. Miller

future and it could be significant to the company."

The refuge is thought to hold large oil reserves. Environmentalists say such development would harm caribou and other wildlife that use the coastal plain. Congress is to decide the controversial issue.

Separately, the head of Chevron Corp., the nation's fourth largest oil company, also said oil prices may rise

See Page D-4, OIL

OIL: Chevron expects price rise

Continued from Page D-1

to \$20 a barrel by year's end. But he said that would not be high enough to stimulate U.S. drilling or thwart the possibility of a 1970s-type energy crisis in a few years.

As a result of reduced drilling following the 1986 oil price slump, Chevron Chairman George M. Keller told shareholders at the company's annual meeting, "our nation faces a period of increasing dependence on foreign energy supplies."

Arco's streamlining in 1986 trimmed its cost of producing oil in the lower 48 states from \$17 per barrel at the beginning of the year to \$12.40 at year-end. That figure was expected to be pared down even more this year, the company said.

Two weeks ago, Arco reported first-quarter earnings of \$239 million, or \$1.31 per share, a decrease of 20 percent from a year earlier when it earned \$299 million, or \$1.64 per share.

The first-quarter results, blamed on depressed oil prices, did not reflect the sharp rise in oil prices in recent weeks to about \$18 per barrel.

At the Chevron meeting, Keller said depressed prices for crude caused the top 25 U.S. oil companies to lose some \$100 billion in revenue last year, forcing them to cut their budgets for drilling and other activities by a third or more, he said.

Chevron's 1986 earnings plunged 54 percent to \$715 million, and revenue fell 40 percent to \$27.5 billion. The company reduced its workforce from 51,000 employees worldwide to about 41,000, nearly 28,000 fewer than the combined Chevron and Gulf workforce three years ago.

Last week, Chevron announced it rebounded from an \$86 million loss in the fourth quarter of 1986 by recording earnings of \$198 million in the first quarter of 1987.

Keller said declining U.S. oil production and rising consumption had caused U.S. oil imports to increase by a million barrels a day last year to the highest level since 1980.

"As a result, the petroleum outlook for the United States has changed dramatically," he said. "We're now looking at the very real possibility of another energy crisis in a few years."

2/88 # 7 bi. { 3 bi existing
2 bi. West Sak.
2 bi. ANWR

oil prof. doc
SAVED TEXT

Sam:

Here is an analysis of the attached articles, which relate to Texaco, ARCO, and Standard profits for the first quarter of this year. Obviously these are very preliminary and superficial comments. The concept bears some more looking at.

You will note that Standard gets 97% of its oil from Alaska. If there is a baseline regarding the profitability of Prudhoe/Alaska production, this is it.

8% Standard made \$200 million on \$2.5 billion in sales last quarter. This works out to \$1 in profit for every \$12.50 in sales.

6.35% ARCO, which derives a large amount of its oil from Alaska (but less than Standard), made \$238 million on \$3.75 billion in sales last quarter. This amounts to \$1 in profit for about every \$16 in sales.

1.4% On the other hand, Texaco (a more diversified producer/refiner/marketer with a relatively small share of Prudhoe), made \$118 million on \$8.5 billion in sales. This is \$1 in profit for every \$70 or so in sales. (The Chapter 11 stuff can't have had too big an impact on Texaco. First 3.42% of all, their assets are protected under Ch. 11. Second, last year they only made \$328 million on \$9.6 billion in sales -- still only \$1 in profit for \$30 in sales.)

Also note that Standard, by juggling the figures in its vertically integrated operations, is able to derive suddenly higher profits (14 times higher than last year) from marketing and refining. ARCO is similar, and brags about the ability to do well in a low-price environment. These guys are killing us!

It would be fun to compare annual/quarterly reports for North Slope/other producers, talk to the PR guys at the different companies, and figure out how massive the Alaska-derived profits really are at Standard and ARCO.

Texaco Profit Plunged 64% In First Quarter

Drop Reflects Oil Industry Conditions, Costs Tied To Pennzoil Litigation

A WALL STREET JOURNAL News Roundup

Texaco Inc. reported that net income fell 64% in the first quarter, reflecting depressed conditions in the oil industry as well as "direct and indirect costs" related to the company's legal battle with Pennzoil Co.

Net income fell to \$118 million, or 49 cents a share, from \$328 million, or \$1.37 a share. Revenue dropped 11% to \$8.5 billion from \$9.6 billion amid lower crude oil and petroleum product prices.

Texaco said the the quarter's results reflected the "rapidly changing market" for refining and marketing operations, where profit margins have been eroding in the face of higher crude oil prices. By comparison, refining and marketing margins rose a year earlier when crude oil prices were falling sharply.

Commenting on the Pennzoil litigation, James W. Kinnear, chief executive officer, said "along with the added legal fees and interest costs, the uncertainties surrounding judicial developments had a negative effect on the company's supply and trading operations. However, now that Texaco Inc. is free to pursue its court appeal without further threats of bond and lien pressures, many of those previous uncertainties have been removed."

Texaco, White Plains, N.Y., filed earlier this month under Chapter 11 of the federal Bankruptcy Code to forestall enforcement of a \$10.3 billion judgment against it awarded to Houston-based Pennzoil by a Texas court in 1985. Under Chapter 11, a company receives court protection from creditors while it works out a plan of reorganization.

Texaco said foreign-currency translation losses totaled \$7 million in the latest quarter, compared with gains of \$9 million a year earlier.

Exploration and production earnings in the U.S. fell to \$41 million from \$75 million a year ago, while manufacturing and marketing operations in the U.S. had a \$55 million loss, compared with year-earlier earnings of \$39 million. The loss reflected substantially lower petroleum product prices, Texaco said.

Outside the U.S., exploration and production earnings rose to \$163 million from \$108 million, because of lower expenses chiefly in Latin America and Europe, as well as reduced taxes. Foreign manufacturing and marketing operations earned \$61 million, down from \$262 million a year earlier, reflecting a sharp reduction in petroleum product prices in European areas.

Texaco said corporate and nonoperating expenses have been reduced, and that the latest quarter also benefited from a \$52 million reduction in estimated income tax liability applicable to prior years.

Capital and exploratory expenditures world-wide declined to \$364 million in the quarter from \$556 million a year earlier, because of exploration program cut-backs.

Texaco shares closed yesterday at \$33.75, up \$1.75, in heavy New York Stock Exchange composite trading.

Three Oil Firms Report Lower Quarterly Profit

Standard's Decline Was 21%;
 Net Fell 98% at Ashland,
 20% at Atlantic Richfield

A WALL STREET JOURNAL News Roundup
 Three U.S. oil companies posted earnings declines for the latest quarter, reflecting lower profit margins.

Earnings fell 21% at Standard Oil Co., 20% at Atlantic Richfield Co. and a whopping 98% at Ashland Oil Inc.

At Ashland and Arco, product prices failed to keep pace with rising crude oil prices while at Standard, the drop reflected lower Alaskan crude oil prices compared with a year ago.

Standard Oil Co.

Cleveland-based Standard posted a 14% decline in first-quarter revenue to \$2.49 billion from \$2.91 billion in 1986.

The company said Alaskan crude oil prices dropped 23.1% to an average price of \$15.51 a barrel during the quarter, compared with \$20.18 in the year-ago period.

The company gets 97% of its oil from Alaska.

Standard said first-quarter operating profit from exploration and production dropped 30% to \$327 million from \$464 million in 1986, while operating profit from refining and marketing—aided by lower crude oil costs—jumped sharply to \$72 million from \$5 million in the year-earlier quarter.

The company said that exploration expenses dropped 72% to \$43 million from \$152 million in 1986 because of lower dry-

	MARCH 31 QUARTER NET INCOME		1987		1986		% chg.
	in millions	per share	in millions	per share	in millions	per share	
Arco	\$239	1.31	\$299	1.64	-	-	- 20
Ashland	\$0.7	.02	\$41.6	1.20	-	-	- 98
Standard	\$200	.85	\$253	1.08	-	-	- 21

hole and support costs, and lower field geological and geophysical expenses, among

Separately, Standard disclosed that its director: .. been discussing British Petroleum Co.'s proposed purchase of the company with BP representatives. The disclosure suggests that the stalemate over the takeover proposal may be easing, and it also raises the possibility that Standard may be able to extract a higher price from BP.

Standard said its directors haven't yet reached a decision on BP's tender offer of \$7.4 billion, or \$70 a share, for Standard's publicly held shares. The company said the seven members of its special committee, which consists of directors who are neither Standard officers nor affiliated with BP, met yesterday and will continue their discussions.

other reasons.
 Robert B. Horton, chairman and chief executive officer, said that despite the lower first-quarter results, the company has "done well, even with the lower prices. Refining and marketing results improved, and the cost-cutting and restructuring we did last year is paying off."

As previously reported, Standard said the special committee would make a recommendation on the tender offer no later than yesterday. The company didn't elaborate on the postponement. BP already owns about 55% of Standard's common shares.

Standard said BP had extended the tender offer to 12:01 a.m. EDT May 5 from 12:01 a.m. next Wednesday.

In New York Stock Exchange composite trading yesterday, Standard closed at \$71, up 50 cents, on volume of 2.2 million shares.

Ashland Oil Inc.

The Ashland, Ky.-based company said higher crude oil prices and excess industry inventories contributed to an \$8.8 million operating loss in its second quarter ended

March 31.

Net income included a gain of \$9.5 million from the transfer of funds to an employee stock ownership plan.

The average number of common and common-equivalent shares outstanding increased to 32.1 million from 29.5 million in 1986.

Revenue dropped 11% to \$1.52 billion from \$1.71 billion in the 1986 quarter. Revenue excludes excise taxes.

Ashland, which had expected to report a decrease in earnings, said that it was hurt by the performance of its Ashland Petroleum Co. and SuperAmerica units. Ashland Petroleum posted an operating loss of \$34.6 million for the quarter, compared with operating profit of \$34.8 million in 1986. SuperAmerica, a chain of convenience and self-serve gasoline outlets, posted a \$51,000 operating loss during the quarter, compared with operating profit of \$17.5 million in the year-earlier period.

"While crude oil prices increased in line with OPEC policy, unseasonably warm weather and high product inventories throughout the industry kept product prices from increasing as rapidly," said John R. Hall, Ashland chairman and chief executive officer.

Ashland produces little crude. As a result, the company is hurt when prices for crude rise more rapidly than prices of gasoline and other refined products.

Mr. Hall nevertheless said that Ashland's profit margins are expected to pick up with the onset of the summer driving and road construction season.

Net income for the six months slid 70% to \$27.9 million, or 86 cents a share, from \$91.9 million, or \$2.68 a share, in the year-earlier six months. Revenue dropped 18% to \$3.02 billion from \$3.69 billion in the 1986 quarter.

Ashland shares closed yesterday at \$59.875, off \$1, in New York Stock Exchange composite trading.

Atlantic Richfield Co.

Los Angeles-based Arco said its profit decline resulted from lower margins that reflected the lag in the rise of product prices compared with crude-price in-

creases.

Revenue declined 13% to \$3.74 billion from \$4.29 billion.

But Lodwick M. Cook, chairman, said he was "extremely pleased" with the company's performance because it "demonstrates Arco's earning power in a lower crude-price environment."

Reductions in Arco's exploration and operating costs helped earnings in the latest period, Mr. Cook said. Exploration expenses totaled \$75 million in the quarter, down from \$137 million a year ago.

Arco shares closed yesterday at \$84.50, up 25 cents, in New York Stock Exchange composite trading.

NORTH SLOPE ALASKA OIL DEVELOPMENT COSTS IN THE U.S. - 1981 - 1986

(Millions \$)

	<u>STANDARD</u>	<u>APCO</u>	<u>CONOCO</u>	<u>TOTAL</u>
Alaska	\$1,071.3	\$ 79.3	n/a	\$ 1,051.3
Alabama	5.4	0.6	-	6.0
Arizona	3.4	0.4-	-	3.8
Arkansas	1.9	51.4	-	53.3
California	1,723.0	69.5	23.8	1,816.3
Colorado	146.3	99.5	-	245.8
Connecticut	1.1	12.5	0.1	13.7
Delaware	0.1	0.2	-	0.3
District of Columbia	2.0	-	-	2.0
Florida	2.3	15.4	0.1	17.8
Georgia	57.2	16.2	0.1	73.5
Hawaii	0.3	-	-	0.3
Idaho	79.4	0.3	5.0	84.7
Illinois	79.4	46.2	0.4	126.0
Indiana	1.3	45.1	1.0	47.4
Iowa	1.6	30.7	1.3	33.6
Kansas	3.0	75.2	-	78.2
Kentucky	1.4	9.4	0.5	11.3
Louisiana	113.0	23.7	0.9	137.6
Maine	5.6	0.2	0.1	5.9
Maryland	23.0	2.4	0.1	25.5
Massachusetts	15.1	35.2	0.2	50.5
Michigan	3.0	57.3	0.4	60.7
Minnesota	43.5	16.9	0.1	60.5
Mississippi	1.3	0.6	-	1.9
Missouri	23.0	30.0	0.1	53.1
Montana	2.4	0.6	-	3.0
Nebraska	63.9	1.0	-	64.9
Nevada	2.3	5.4	-	7.7
New Hampshire	0.2	0.1	-	0.3
New Jersey	3.5	32.6	-	36.1
New Mexico	6.3	0.6	-	6.9
New York	122.3	415.0	3.9	541.2
North Carolina	1.9	40.3	0.5	42.7
North Dakota	1.3	2.5	-	3.8
Ohio	15.4	67.3	0.6	83.3
Oklahoma	146.7	192.6	3.5	342.8
Oregon	13.9	99.1	10.0	123.0
Pennsylvania	25.2	150.0	0.3	175.5
Rhode Island	0.3	0.15	0.2	0.65
South Carolina	2.9	0.1	0.2	3.2
South Dakota	0.1	0.5	-	0.6
Tennessee	0.6	1.25	-	1.85
Texas	2,339.3	1,114.8	21.3	3,475.4
Utah	6.4	129.1	1.0	136.5
Vermont	1.0	0.3	-	1.3
Virginia	1.6	0.6	0.1	2.3
Washington	211.3	506.3	47.5	765.1
West Virginia	0.1	0.15	-	0.25
Wisconsin	3.9	173.6	0.5	178.0
Wyoming	12.5	1.5	-	14.0
TOTAL COSTS	35,745.1	33,669.6	124.1	69,538.8

STANDARD : Total accounts paid to vendors in 1981 - 1986 for West side Prudhoe Bay field \$7.003 billion

 : Accounts paid to vendors in 1985 - 1986 for Endicott field development \$627 million.

 : Payments paid to identified U.S. vendors traceable to a ZIP code \$6.745 billion.

APCC : Total payments for tangible items for East side of Prudhoe Bay, Kuparuk and Lisburne 1980 - 1985 \$3.669 billion

CONOCO : Payments for goods and services to develop Milne Pt. oilfield, 1980-86 - \$124 million.

It is estimated that the cost of developing the Prudhoe, Kuparuk, Milne Pt., Lisburne and Endicott oil fields on the North Slope of Alaska has exceeded \$36 billion since 1974. This amount includes the cost of the trans-Alaska pipeline (approximately \$8 billion). The fields currently supply 20% of U.S. domestic oil production.

U.S. Dependence on Oil Imports Is Shooting Up But Congress, White House Fumble With Policy

By ROBERT E. TAYLOR

Staff Reporter of THE WALL STREET JOURNAL
WASHINGTON—Less than two years ago, 27% of the U.S. oil supply was imported. Today the foreign share is about 40%, but although there's cause for concern, Congress and the Reagan administration can't seem to get together to reverse the trend.

"You have to ask why they don't do something," says Charles DiBona, president of the American Petroleum Institute, the domestic oil industry's leading trade group. Although Mr. DiBona has a direct interest in seeing imports' share of the U.S. market diminish, his complaint is shared by many experts outside the industry.

"We aren't doing anything to make foreign oil less important," says Eli Bergman, executive director of Americans for Energy Independence, a private foundation.

Interior Secretary Donald Hodel predicts the return of gasoline lines in as little as two years. Failing to curb imports, he says, is like telling oil-producing countries, "Take advantage of us, we're not going to defend ourselves." The Fund for Renewable Energy and the Environment, a coalition of environmental groups and supporters of alternative energy sources, who seldom agree with Mr. Hodel, warns that the U.S. is failing to prepare for "inevitable" oil price increases that "could well imperil the national economy and the country's security."

Which Way Do We Go?

The difficulty is reaching agreement on what to do. The oil industry and some others want to encourage increased U.S. production by means of an oil-import fee or with tax incentives. But a price-raising import fee or tax breaks for the oil industry raise steep political hurdles in the form of strong opposition from oil-consuming interests. Meanwhile, environmentalists' proposals to stimulate conservation and increase use of substitute fuels are blocked by the administration.

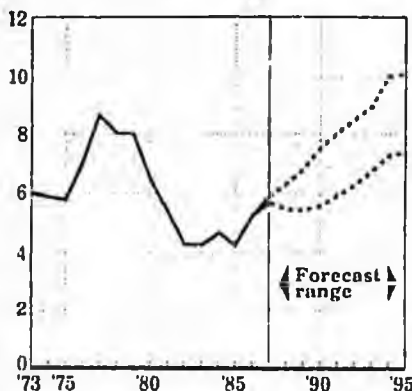
Currently stirring controversy is a proposal by Senate Finance Chairman Lloyd Bentsen (D., Texas). He recently got his committee to amend the pending trade bill to require the president to do whatever is necessary to keep oil imports from exceeding 50% of the U.S. supply, subject to congressional veto. But New Englanders and Midwesterners oppose the amendment as a backdoor route to an import fee that would raise fuel costs. "It's simply unfair," says Sen. John Chafee, (R., R.I.), whose constituents get two-thirds of their energy from oil.

The problem will worsen, forecasters say. Oil imports are expected to top 50% of the U.S. supply between 1990 and 1995. That would heighten the importance of the volatile Persian Gulf. Although the U.S. now gets only about 6% of its oil from the gulf, that region is expected to dominate world oil markets in the 1990s when the current world oil glut is expected to be over.

Congress has made small energy-conservation moves. It passed a bill, reluc-

U.S. Net Oil Imports

Actual and forecast, in millions of barrels per day.



Sources: Energy Information Administration through 1986 and Energy Department forecasts thereafter.

tantly signed by President Reagan, reinstating appliance-efficiency standards. The House currently is exploring ways of diverting 2% of all oil imports into the nation's Strategic Petroleum Reserve, and there has been talk of a gasoline tax that would be used to help cut the budget deficit while discouraging consumption.

Although administration officials say the president has supported "appropriate" responses to the oil-import problem, such as lifting the oil-industry's "windfall" profits tax and opening more federal lands to drilling, industry leaders are skeptical that much will be done. David Wilson, president of the Independent Petroleum Association of Mountain States, says that both Congress and the administration "are hoping the situation will go away without action on their part."

Just last month, Mr. Reagan killed a seven-month drive by some administration officials to get him to take strong new action. The Energy Department urged the president to propose tax credits and quick expensing of oil-exploration costs totaling \$560 million to \$960 million annually. It projected these would boost domestic production after five years by 500,000 barrels a day, or about 6%.

According to Mr. Hodel, some cabinet members were loath to open last year's tax law to assaults by special interests. Top officials also balked, insiders say, at the cost of tax breaks and the difficulty of pushing them through Congress.

Oil Reserve Plan Scrapped

Also scrapped was an Energy Department plan to buy more oil for the strategic reserve. It urged that private investors be allowed to own the oil through government-backed securities. Instead, Mr. Reagan said he would support tripling his proposed purchase rate for the reserve to 100,000 barrels a day only, if Congress found a way to pay for it.

"That makes no sense," says oil-state lawmaker Bennett Johnston (D., La.), chairman of the Senate Energy Committee. Even the administration says such reserves are crucial to enable the U.S. to comfortably ride out small oil-supply dis-

ruptions like those of the 1970s.

Talk of gasoline taxes and alternative oil leasing systems was blocked by Reaganite aversion to taxes and regulation. Import fees were doomed by the administration's projection that they would be extremely costly without producing much more oil.

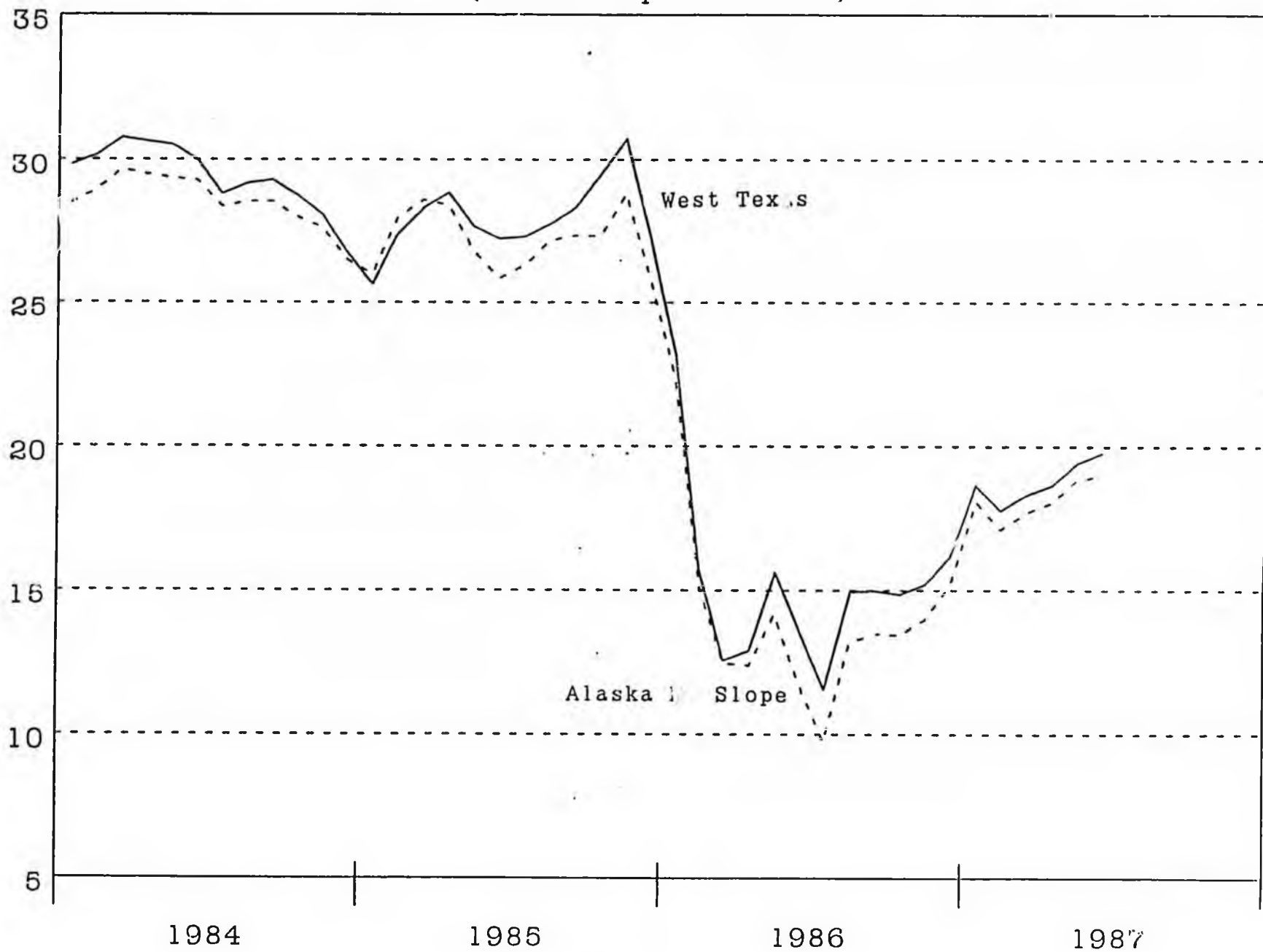
Harvard professor William Hogan argues that the benefits of a \$10-a-barrel fee actually would exceed its costs. But the Energy Department doesn't buy Mr. Hogan's view. Neither does Robert Fri, president of Resources for the Future and a former head of the Energy Research and Development Administration, who says, "Energy is a long-term problem, and quick fixes will do more harm than good."

But even Mr. Fri says that "the administration should have a more comprehensive program," mainly in research and development on cheaper oil production and ways to use substitute fuels, such as methanol, to fuel automobiles.

Curbing oil imports hasn't been a priority, complains the oil industry's Mr. DiBona. "In this country, we tend to deal with the immediate crisis, not the long-term problem," he says, faulting administration officials for inattention to energy amid the distractions of Iran-Contra hearings and other issues.

Rep. John Dingell (D., Mich.) charges that Mr. Reagan has a "do-nothing approach" to preparing for "the next energy crisis." Others contrast the inaction on oil imports with Mr. Reagan's quickness to defend Persian Gulf shipping. Irwin Steltzer, the director of the Energy and Environment Center at Harvard University's Kennedy School of Government, says, "I think our (energy) policy is called aircraft carriers."

West Texas Intermediate Spot vs
Alaska N. Slope at the Gulf Coast
(Dollars per Barrel)



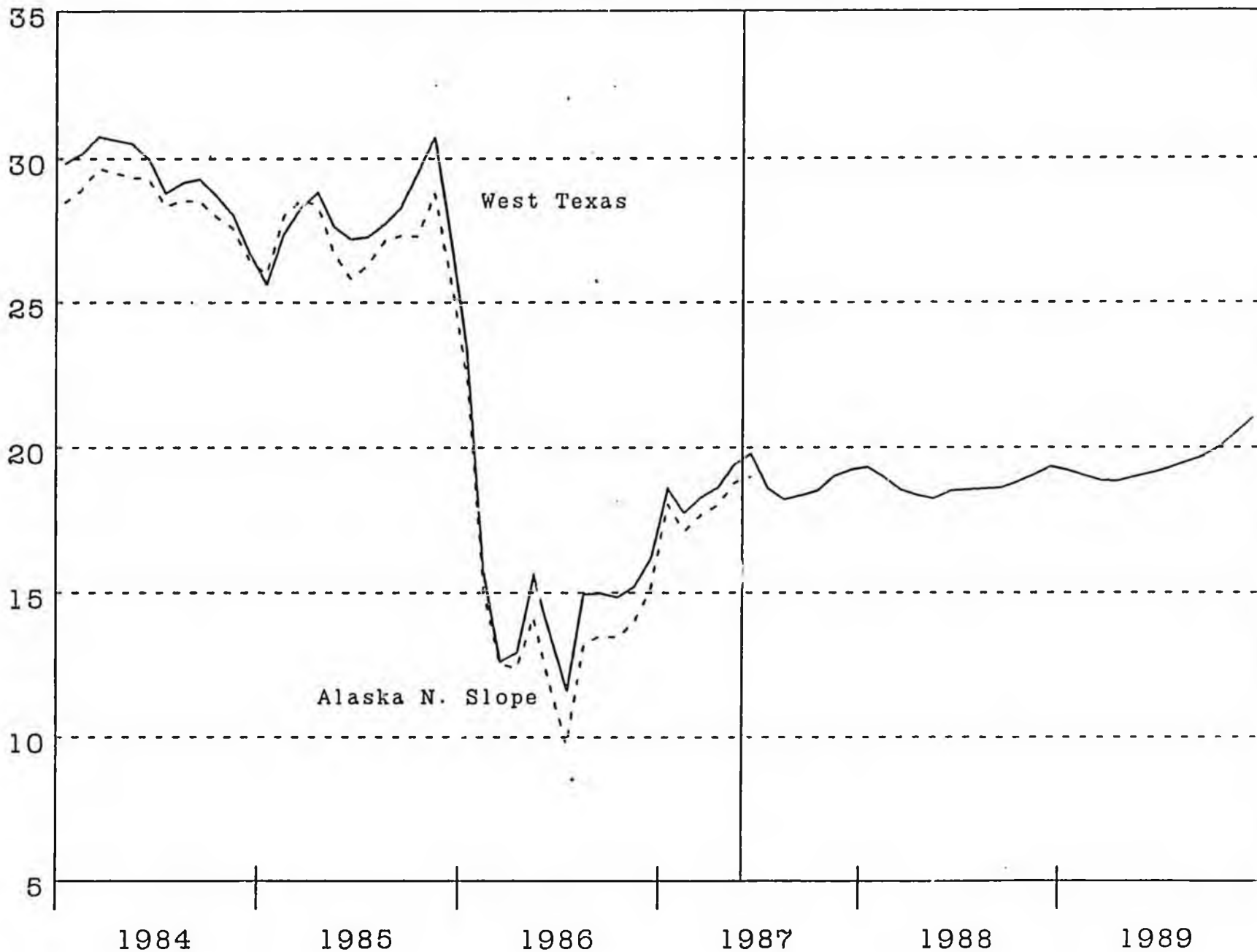
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DRI ENERGY

OIL PRICE FORECAST COMPARISON WEST TEXAS INTERMEDIATE SPOT MARKET PRICE (U.S. DOLLARS PER BARREL)

<u>FORECAST PREPARED</u>	<u>YEAR</u>			
	<u>1986</u>	<u>1987</u>	<u>1988</u>	<u>1989</u>
JUNE 1, 1987	\$15.12	\$18.55	\$18.73	\$19.50
NOVEMBER 1, 1986	\$15.15	\$17.58	\$18.46	\$19.42
MAY 1, 1986	\$16.20	\$17.22	\$18.24	\$19.35

West Texas Intermediate Spot vs
Alaska N. Slope at the Gulf Coast
(Dollars per Barrel)



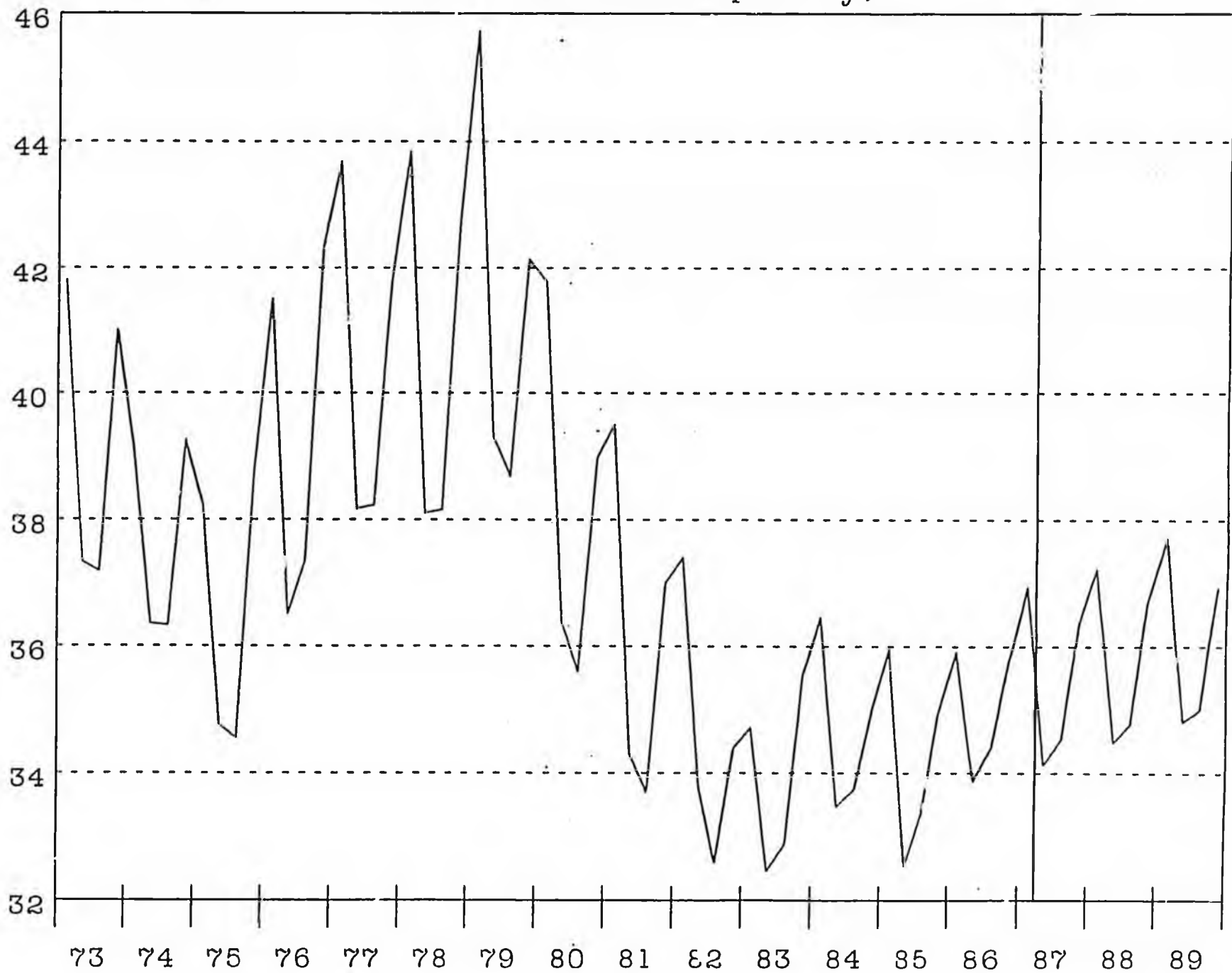
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Seasonally Adjusted Oil Consumption
For the Major 7 Developed Countries
(Million Barrels per Day)



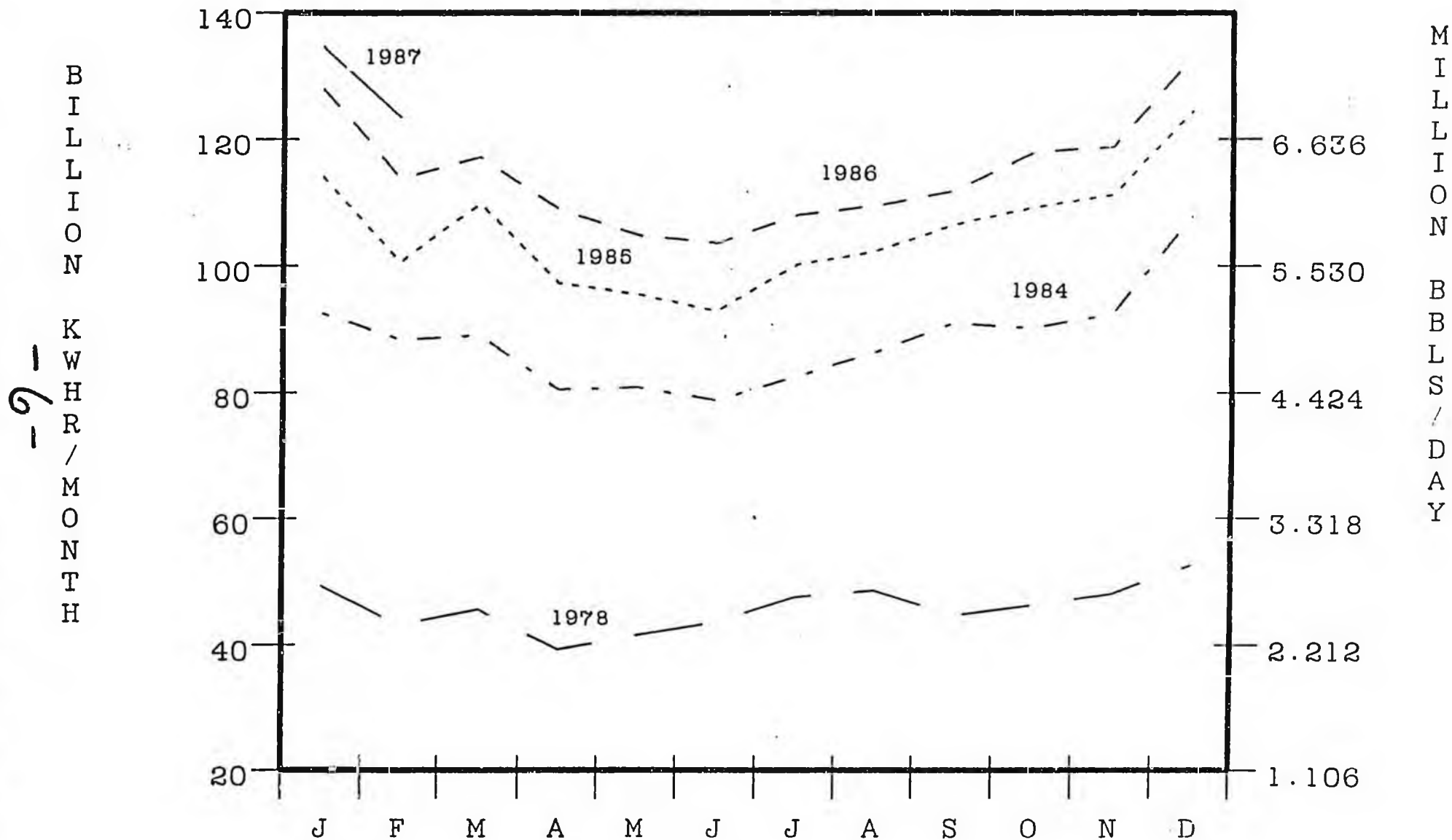
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Developed Country Oil Consumption
(Million Barrels per Day)



-5-

MONTHLY NUCLEAR ELECTRICITY GENERATION
NON-COM COUNTRIES



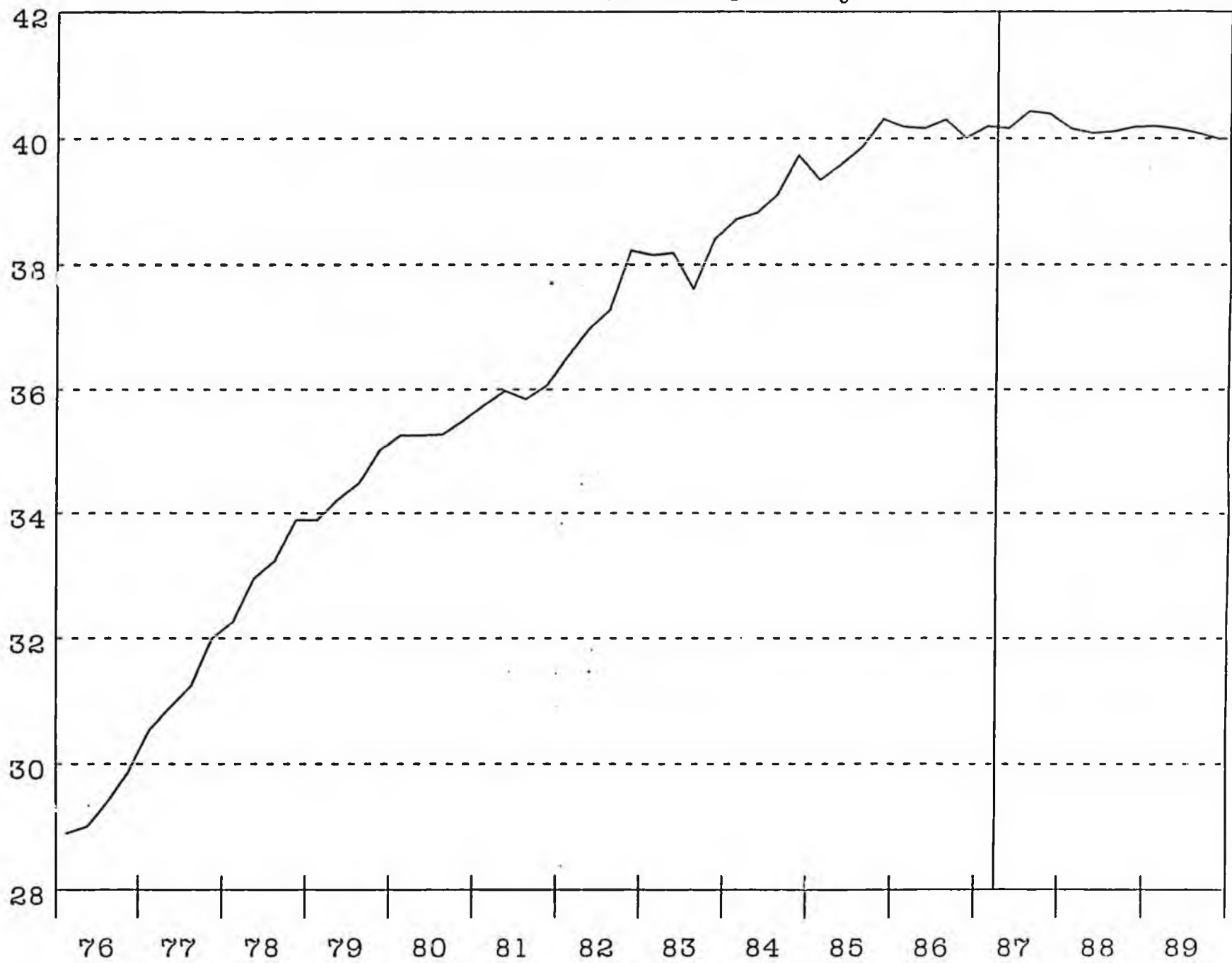
SRC: U.S. DOE MONTHLY ENERGY REVIEW

Developed Country Commercial Oil Inventories
(Million Barrels)



-7-

Non-OPEC World Oil Production
(Million Barrels per Day)



80

OPEC Crude Oil Production
(Million Barrels per Day)



-6-

OPEC Gross Revenue
(Million Dollars per Day)



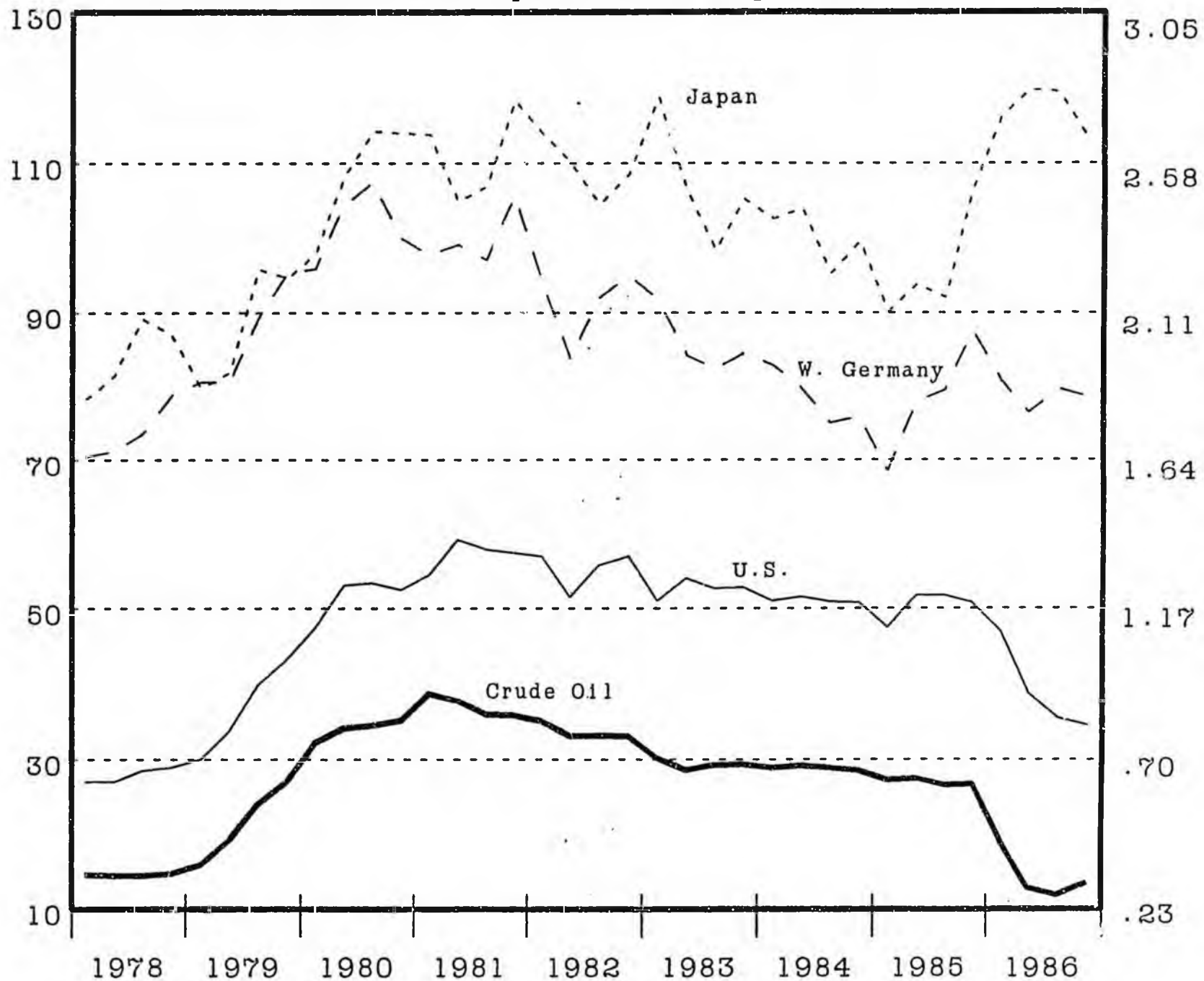
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OPEC Crude Oil Production
Other Than Saudi Arabia, Iran And Iraq
(Million Barrels per Day)



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Comparison of International Gasoline Prices &
U.S. Refiner Acq. Cost of Imp Crude Oil



-12-

Summary of presentation by Michael Smolinski
Director
Fuel Price and World Oil Services
DRI - McGraw Hill

Commitments of
Senator Don Bennett

These are copies of the presentation I made yesterday in Anchorage. You may find them to be useful. Several key points are as follows:

- Page 2 My June 1 forecast puts 1988 West Texas Intermediate crude at \$18.73 per barrel. Estimate for Alaska North Slope crude would be approximately \$17.80.
- Market Fundamentals do indeed support higher prices.
- Page 4 Developed country oil consumption has been on a rising trend since 1983.
- Page 5 Seasonal increase in demand has begun which will increase the call on OPEC production by approximately 3 million barrels per day by year end.
- Page 6 Nuclear Power's competition to OPEC production (worth 2.5 to 3.0 million barrels per day since 1978) is coming to an end. Nuclear power will no longer be reducing oil demand.
- Page 7 Oil Inventories are no longer the problem they were at the end of 1986. They are close to desired levels.
- Page 8 Competition from non-OPEC oil production has peaked. Rising oil demand will now be met by OPEC production.
- Page 9 Shows the extent to which OPEC production has been reduced since 3rd quarter 1986 in order to firm prices and will increase during balance of 1987, 88 and 89 to meet world demand.
- Page 10 Shows that OPEC's revenue is maximized by restraining production (1979/80) and late 1986 early 1987. Revenue is reduced by pushing oil into a market that doesn't want it (1st quarters of 1986).

Page Two
Summary by Michael Smolinski
July 1, 1987

Page 11 Saudi Arabia is not the only OPEC member who
 has restrained production.

Page 12 OPEC's efforts to restrain production and raise
 prices are an effort for them to achieve what
 they perceive to be their fair share of what
 the consumer is willing to pay.

Final Comment:

The State of Alaska should separate the process of forecasting
oil prices and managing oil revenue risk.

Forecasting of oil prices should emphasize trying to
accurately predict the most likely price so that the
forecasting process may be evaluated and steadily improved.
Oil price forecasting is very important to Alaska.

Forecasting process should also entail an assessment of risk.

Revenue forecasting process should begin with an assessment
of the most likely revenue (again to facilitate evaluating and
steadily improving the process). Then to handle risk, planned
spending decisions should be made through careful assessment
of the risk and through use of contingency planning to manage
the risk.

Process should separate the three step process.

Oil Price Forc - Revenue Forc - Managing revenue risk

State of Alaska
MEMORANDUM

Office of the Governor

Division of Policy

P.O. Box AM, Juneau, AK, 99811

Tel. 465-3568 / Mail Stop 0164

TO: Mary Halloran
Director

DATE: 18 June 1987

FROM: Gregg Erickson
Senior Economist

SUBJECT: Correction

My memorandum of June 16, describing the Deakin report on "Oil Industry Profits in Alaska," contains the following paragraph:

- In every year since 1978, profits removed from Alaska have exceeded investments in the state; in 1981 the industry's net investment position became positive. In 1985, \$4.59 billion was expatriated from Alaska, compared with \$0.57 billion reinvested [p. 8].

One of the figures in the second sentence is in error. It should read:

.....In 1985, \$4.51 billion was expatriated from Alaska, compared with \$0.57 billion reinvested [p. 8].

Please correct your copy.

OFFICE OF
MANAGEMENT & BUDGET
OCT 13 1987

STRATEGIC PLANNING

STATE OF ALASKA
DEPARTMENT OF REVENUE
OIL AND GAS AUDIT DIVISION

M E M O R A N D U M

To: Hugh Malone, Commissioner, Department of Revenue
Through: William Floerchinger, Director, Oil and Gas Audit Division
From: Roger Marks, Petroleum Economist
Date: October 8, 1987
Subject: Model to Evaluate Economic Incentives for Drilling Wells

For your information attached is a description of a model we have developed over the past six months which evaluates the economic incentive for in-fill drilling. In addition to being integral to our continuing revenue forecasting function for determining future well numbers, upon which the ELF and subsequently the severance tax is based, as shown in the description the model also illustrates the economic inefficiency of the current severance tax structure, and suggests the possible effect CSHB 164 (the modification to the ELF formula introduced by the House in the 1987 session) may have on drilling behavior.

The results can be summarized as follows:

1. The ELF provides an incentive to drill wells simply to reduce the severance tax. We estimate that 19 percent of the drilling at Prudhoe Bay may be attributable to this effect.
2. Accordingly, the State may be subsidizing well drilling \$27 million per year.
3. CSHB 164 removes most of the tax subsidy effect.
4. CSHB 164 would also reduce drilling activity.

Attachment

cc: Chuck Logsdon, DOR
Gregg Erickson, OMB
Ed Phillips, DNR
Bill Van Dyke, DNR
Russ Douglas, AOGCC

A Model to Evaluate the Economics of Drilling Additional Wells

Roger Marks
State of Alaska Department of Revenue
Division of Oil and Gas Audit
Petroleum Research Section
October 1987

I. Introduction

The oil production severance tax structure in Alaska causes the tax to be sensitive to the number of wells in a field. Levied on non-royalty barrels, the tax is the product of the wellhead price (market price less shipping and pipeline costs), the severance tax rate, and the economic limit factor (ELF). The ELF is a number between zero and one which reduces the severance tax as well productivity declines and a field approaches its economic breakeven point:

$$ELF = \left(1 - \frac{PEL}{TP} \right)^{\left[\frac{460 * WD}{PEL} \right]}$$

where PEL = the monthly production rate at the economic limit
TP = total production during the month for which the tax is to be paid
WD = the total number of well days in the month for which the tax is to be paid

Thus, for example, with all other things equal, as wells increase, PEL will increase, PEL/TP will increase, the base of the exponent will decrease, and the ELF, along with severance tax, will decrease.

Recently there have been legislative proposals to modify the severance tax structure, notably the form of the ELF. Meaningful judgements on the merits of the proposals will depend, among other things, on how they affect development, productivity, profitability, and State revenues.

The State of Alaska Department of Revenue's current forecasting model has a module that computes the economic rent accruing to the producer (i.e. profit) of specific fields to assess whether or not they are feasible to produce given price and volume scenarios. When profit is negative, production is delayed until a start-up year generating positive profit is found. This reduces the likelihood that the model will project revenue from uneconomic fields. When profit is positive the model finds the profit maximizing amount of enhanced recovery. (See Appendix A.)

Projected price, volume, and well numbers are exogenous input, with the latter two based on producer public information and State engineering assessments. They reflect the current and announced extent of development, a rather limited time horizon.

Consequently, the Department has developed a model to examine the economics of drilling additional wells in developed fields. Such a model indicates the degree of extra in-fill drilling and production that may occur to maximize economic rent for primary recovery, and is also useful for analyzing potential severance tax structures.

II. The Model

The crux of the model is the relationship it establishes between additional wells and the production profile. On that matter the model is necessarily generic while reservoirs are of course unique, but reflects general engineering principles. The model does allow reasonable systematic comparative policy analysis in an area where precise answers are unknowable. The following discussion accents the Prudhoe Bay and Kuparuk fields.

The production decline characteristics of many oil wells and fields follow exponential declines. The slope of the decline curve is called the exponential decline rate, a , where:

$$a = \frac{\ln\left(\frac{q_i}{q_f}\right)}{t}$$

q_i = production rate at the beginning of any time period during the decline

q_f = production rate at the end of the time period

t = number of years between q_i and q_f

Production in any year is $1/e^a$ times production in the previous year, where e , the number whose natural logarithm is one, is approximately 2.71828. We henceforth refer to $1/e^a$ as the production multiplier, P . Similarly, the well count will decline as producers are converted to injectors as production, saturation, and pressure drops. The well decline multiplier is estimated at $.5*(1+P)$.

In general, the major impetus for in-fill drilling is to produce a finite amount of oil sooner. Given an initial decline rate, a_B , additional wells will slow down the decline rate on a field basis to a_N , and the initial production multiplier P_B ($1/e^{a_B}$) increases to P_N as a_B decreases. a_B will decrease at a decreasing rate as wells are added. At Prudhoe Bay a_B is estimated to be 0.140 (P_B at 0.86936), and at Kuparuk 0.090 (P_B at 0.91393).

As wells increase the production multiplier will increase such that

$$P_N = P_B + f(w).$$

where w is the number of additional wells, and production for a given year, V_t , will be

$$V_{t-1} * P_H$$

where V_{t-1} is production in the previous year.

$f(w)$ is approximated by the form

$$C * \left[\ln \left(\frac{(w + T^{\frac{x-1}{x}})^x}{T^{x-1}} \right) \right]$$

where T = total wells prior to decline. For Prudhoe Bay T is estimated at 591 and Kuparuk 305 (adjusted for non-producing days).

$x = 3$ is determined such that

$$\left[\ln \left(\frac{(.25 T + T^{\frac{x-1}{x}})^x}{T^{x-1}} \right) / \ln \left(\frac{(T + T^{\frac{x-1}{x}})^x}{T^{x-1}} \right) \right] = 0.5$$

This calibrates $f(w)$ such that 50 percent of the change in $f(w)$ that would result from doubling T is realized after T is increased 25 percent.

$$c = \left(\frac{1}{e^{a_b - g(r)}} - \frac{1}{e^{a_b}} \right) / \ln \left(\frac{(w + T^{\frac{x-1}{x}})^x}{T^{x-1}} \right)$$

This coefficient calibrates $f(w)$ such that as $w = T$ (i.e. the number of wells is doubled), ag is reduced by $g(r)$.

$$g(r) = .001 * r * K$$

where r is the percentage of total reserves recovered after peak (estimated to be 38 percent for Prudhoe Bay and 59 percent for Kuparuk) and K is a constant estimated at 0.18.^{1/} For Prudhoe Bay c is estimated to be 0.0009088 and for Kuparuk 0.0016475.

The intercept term $(T^{\frac{x-1}{x}})$ calibrates $f(w)$ so $f(w) = 0$ when $w = 0$.

^{1/} The derivation of K is enigmatic. It is the essence of the model and it is unknowable. It was selected because 1) it is a constant that applies to all fields, and 2) it simulates expected drilling behavior for given prices. Given its tenuity, the quality of the results discussed herein, not the quantity, should be emphasized.

In practice there is a limited amount of reserves remaining before exponential decline decays into arithmetic. We have assumed this to be 75 percent of post-peak reserves. For Prudhoe Bay this is estimated to be 2,886 million barrels after 1989 and 574 million for Kuparuk. The model stops exponential and begins arithmetic decline when accumulated post-1989 production reaches this estimated limit, decreasing production each year by a constant amount equal to the difference in production between the prior two years. (Note that arithmetic decline will begin sooner where more wells have been drilled. This gives a more rapid late-life decline where more wells had been drilled, accelerating the arrival of economic shutdown; consequently total recovery over the economic life of the field may be less with greater numbers of wells even though profit is greater.)

The model is incorporated into a conventional discounted cash flow profitability model specific to the North Slope (see Appendix A). A number of additional wells (w) is exogenously inputted (along with their costs),^{1/} and they are allocated over each of the five years 1990 through 1994 by a percentage declining by a constant amount (thirty percent through ten percent in increments of five percent).^{2/} For purposes of the ELF calculation it is assumed that ninety percent of the additional wells are producing at any one time. A ceiling of T is put on w . Volume is adjusted as specified above. The model cuts off production when after tax net value is negative. The number of additional wells that maximizes profit is found iteratively.

III. Exemplary Results

Our estimates of the optimum number of additional wells under current law, as a function of constant real Pump Station One (PS1) price, are as follows. (These prices are approximately \$4 under market prices.)

<u>Price</u>	<u>Additional Wells</u>	
	<u>Prudhoe</u>	<u>Kuparuk</u>
\$15	49	33
\$20	155	103
\$25	447	175

^{1/} As a demand response it is assumed that well costs will change 20 percent as much as oil prices.

^{2/} This is a five year drilling program. Given the future price omniscience implicit in this model, net present value would be maximized if all additional wells were drilled the first year. However, given the certainty of error in the price forecast, and given the relatively greater down-side (vs. up-side) price risk, it is probable that the cost of being too conservative is less than the cost of being too aggressive in the event of forecast errors (adaptation is possible in the event of an incomplete program), and thus the prudent manager would extend the drilling program.

Table 1 compares the well count, production volume, and profit, with and without an optimized in-fill drilling program, at a \$15 PSI price for Prudhoe Bay.

Table 2 compares the well count and production volume between optimized in-fill drilling programs at \$15 and \$20 at PSI for Prudhoe Bay.

Tables 3 and 4 show the same information for Kuparuk.

IV. Issues

A. Economic Inefficiency of the Current Severance Tax Structure

There are two incentives for drilling additional wells under the current law. The first obvious reason is to procure more volume sooner. We will call this Effect V (for Volume). The second reason pertains to the ELF form. Recall that with all other things being equal, a greater number of wells will make for a smaller ELF, and subsequently a reduced severance tax. We will call this Effect T (for Tax). In practice both effects are working simultaneously, and in fact are quite synergistic, but it is possible to estimate what portion of drilling behavior can be attributed to each effect.

If we remove one effect, we can observe the pure behavior of the other effect, and compare the pure behavior of both effects to indicate the relative influence of each effect when they work simultaneously.

The model suggests that additional drilling commences for both Prudhoe Bay and Kuparuk at a \$13 PSI price. We can remove Effect V by setting c at zero. Then we can observe the pure Effect T; that is, we can find a higher price such that the reduced severance tax from a greater number of wells more than offsets the cost of the wells such that it is profitable to drill more wells (even though no additional oil will materialize), merely to reduce the severance tax. (This will happen at a higher price because only one effect is in place here, and because severance taxes are based partly on price, for a given ELF reduction the savings will be absolutely greater at a higher price.) The model suggests this would begin to occur at a price of \$42 for Prudhoe Bay and \$37 for Kuparuk, increases of 223 percent and 185 percent, respectively.

Similarly, we can observe the pure Effect V by removing Effect T by removing the ELF by setting the ELF at one. We can find a higher price such that given a discount rate, the benefit of procuring additional oil sooner pays for the cost of the additional wells such that it is profitable to drill more wells. (Again, it will be at a higher price since only one effect is at work here.) The model suggests this would begin to occur at \$20 for both Prudhoe Bay and Kuparuk, an increase of 54 percent.

Table 1
 Prudhoe Bay
 Comparison of Wells, Volume, and Profit
 With and Without an Optimized In-fill Drilling Program
 \$15 PSI Price

	<u>No Optimization</u>		<u>Optimization</u> (49 wells)		<u>Increased</u>	<u>Increased</u>
	<u>Wells</u>	<u>Volume</u> (mmbbl)	<u>Wells</u>	<u>Volume</u> (mmbbl)	<u>Wells</u>	<u>Volume</u> (mmbbl)
1989	591	558	591	558	0	0
1990	552	485	566	485	14	0
1991	516	422	540	422	24	0
1992	483	367	513	368	30	1
1993	451	319	486	320	35	1
1994	422	277	459	279	37	2
1995	394	241	429	242	35	1
1996	368	209	401	211	33	2
1997	344	182	375	184	31	2
1998	322	158	350	160	28	2
1999	301	138	327	139	26	1
2000	281	120	306	121	25	1
2001	263	102	286	103	23	1
2002	246	84	267	85	21	1
2003	230	66	250	67	20	1
2004	215	48	234	49	19	1
2005	201	30	218	31	17	1
2006	187	12	204	13	17	1
Total		3,818		3,837		19
Profit (\$mm)		15,864		15,874		
Additional Profit						10

Table 2
Prudhoe Bay
Comparison of Optimized In-fill Drilling Programs
\$15 and \$20 PSI Prices

	<u>\$15</u> (49 wells)		<u>\$20</u> (155 wells)		<u>Increased</u> <u>Wells</u>	<u>Increased</u> <u>Volume</u> (mmbbl)
	<u>Wells</u>	<u>Volume</u> (mmbbl)	<u>Wells</u>	<u>Volume</u> (mmbbl)		
1989	591	558	591	558	0	0
1990	566	485	594	486	28	1
1991	540	422	590	423	50	1
1992	513	368	580	369	67	1
1993	486	320	563	322	77	2
1994	459	279	540	281	81	2
1995	429	242	505	245	76	3
1996	401	211	472	213	71	2
1997	375	184	441	186	66	2
1998	350	160	412	162	62	2
1999	327	139	385	141	58	2
2000	306	121	360	123	54	2
2001	286	103	336	105	50	2
2002	267	85	314	87	47	2
2003	250	67	294	69	44	2
2004	234	49	275	50	41	1
2005	218	31	257	32	39	1
2006	204	13	240	14	36	1
Total		3,837		3,866		29

Table 3
Kuparuk
Comparison of Wells, Volume, and Profit
With and Without an Optimized In-fill Drilling Program
\$15 PS1 Price

	<u>No Optimization</u>		<u>Optimization</u> (33 wells)		<u>Increased</u>	<u>Increased</u>
	<u>Wells</u>	<u>Volume</u> (mmbbl)	<u>Wells</u>	<u>Volume</u> (mmbbl)	<u>Wells</u>	<u>Volume</u> (mmbbl)
1989	305	94	305	94	0	0
1990	285	86	294	86	9	0
1991	266	79	282	79	16	0
1992	249	72	270	72	21	0
1993	233	66	257	66	24	0
1994	218	60	243	60	25	0
1995	203	55	227	55	24	0
1996	190	50	212	51	22	1
1997	178	46	198	46	20	0
1998	166	42	185	43	19	1
1999	155	38	173	39	18	1
2000	145	35	162	35	17	0
2001	136	31	151	32	15	1
2002	127	27	141	28	14	1
2003	118	24	132	25	14	1
2004	111	20	124	21	13	1
2005	103	17	115	17	12	0
2006	97	13	108	14	11	1
2007	90	9	101	10	11	1
2008	85	6	94	7	9	1
2009	79	2	88	3	9	1
Total		872		883		11
Profit (\$mm)		3,057		3,063		
Additional Profit						6

Table 4
Kuparuk
Comparison of Optimized In-fill Drilling Programs
\$15 and \$20 PSI Prices

	<u>\$15</u> (33 wells)		<u>\$20</u> (103 wells)		<u>Increased</u> <u>Wells</u>	<u>Increased</u> <u>Volume</u> (mmbbl)
	<u>Wells</u>	<u>Volume</u> (mmbbl)	<u>Wells</u>	<u>Volume</u> (mmbbl)		
1989	305	94	305	94	0	0
1990	294	86	313	86	19	0
1991	282	79	316	79	34	0
1992	270	72	314	73	44	1
1993	257	66	307	67	50	1
1994	243	60	296	61	53	1
1995	227	55	277	56	50	1
1996	212	51	259	52	47	1
1997	198	46	242	47	44	1
1998	185	43	226	44	41	1
1999	173	39	211	40	38	1
2000	162	35	197	36	35	2
2001	151	32	185	33	34	1
2002	141	28	173	29	32	1
2003	132	25	161	26	29	1
2004	124	21	151	22	27	1
2005	115	17	141	19	26	2
2006	108	14	132	15	24	1
2007	101	10	123	11	22	1
2008	94	7	115	8	21	1
2009	88	3	108	4	20	1
2010	0	0	101	1	(na)	1
Total		883		903		20

In summary, the pure Effect T necessitates a 223 percent increase in price for additional drilling to be profitable at Prudhoe Bay, and Effect V a 54 percent increase. Note that the greater the price increase for an effect, the less the presence of the effect influences drilling behavior. Thus these percentages can be thought of as "non-influencing factors," and the relative size of the factors suggests the relative "non-significance" of each effect, or the relative significance of the other effect. Thus when we say Effect T has a factor of 223 and Effect V a factor of 54, the relative significance of Effect T is:

$$54 / (223 + 54) = 19 \text{ percent}$$

and subsequently the relative significance of Effect V is 81 percent. This implies that 19 percent of the drilling at Prudhoe Bay would be attributable to Effect T. At Kuparuk it is 23 percent.

The existence of Effect T causes economic inefficiency; i.e., profit maximizing behavior reduces total economic rent (and net social value). In this case the reduced severance tax would more than pay for the cost of the wells; however, the cost of the wells would be more than the value of the additional oil produced.

This can be illustrated by another "pure" case. Recall that when we removed Effect V, we had the pure Effect T, where the only impetus for drilling was to reduce severance tax. The model showed that for Prudhoe Bay such behavior would ensue at a price of \$42. Suppose price was \$45. The model suggests 199 additional wells would be drilled even though no additional oil would be recovered. Though the cost of the additional wells reduces total economic rent \$748 million (as compared to the case where no additional wells are drilled), producer economic rent actually increases \$15 million. The brunt of the loss accrues to the State in a reduction of severance taxes of \$774 million. (The balance is attributable to small changes in property taxes, state income taxes, and federal income taxes.)

What might Effect T be costing the State now? The Department of Revenue is currently forecasting Prudhoe Bay production for FY 1988 at 561 million barrels with 591 wells (adjusted for non-producing days). The resultant ELF is 0.829. At current prices (subsequent to SOHIO's announced price decrease on October 1) the expected severance tax would be \$686 million. If 19 percent less wells were present with no change in production, the ELF would increase to 0.860 and the severance tax would be \$713 million, an increase of \$27 million.

B. Committee Substitute House Bill 164

CSHB 164, introduced in the 1987 session, introduces a scaling factor and rate of field production into the exponent of the current ELF formula. (The value of the scaling factor determines the level of production for which the ELF is greater than under current law).

This formula makes the ELF much less sensitive to changes in well numbers, especially for Prudhoe Bay, so as to make any pure Effect T behavior essentially undiscernible. Accordingly, we would expect less wells to be drilled than under current law.

Our estimates of the optimum number of additional wells under CSHB 164, as a function of PSI price, are as follows.

<u>Price</u>	<u>Additional Wells</u>	
	<u>Prudhoe</u>	<u>Kuparuk</u>
\$15	0	21
\$20	29	78
\$25	73	153

APPENDIX
Description of Discounted Cash Flow Model

The following is a description of the feasibility and enhanced recovery model used by the Department of Revenue in its petroleum revenue forecasting model. The drilling model developed in this paper was incorporated into the discounted cash flow components of that model to produce the results presented in this paper.

A Model To Assess Economic Feasibility and Optimum Production Volume for North Slope Fields

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Summary. Alaska's revenue-forecasting model computes the economic rent of prospective fields to assess their feasibility to produce given price and volume scenarios. When economic rent is negative, production is delayed until a startup year generating a positive rent is found. If economic rent is positive, the model finds the profit-maximizing EOR amount.

Introduction

Alaska's Dept. of Revenue is responsible for forecasting the state's revenue for planning and budgeting purposes. Petroleum revenues accounted for \$2.3 billion in fiscal year (FY) 1986 (July 1985 through June 1986), or 84% of the total state revenue. These took the form of severance taxes, royalties, corporate income taxes, property taxes, bonuses, rents, and intergovernmental receipts. Of these petroleum revenues, 87% was derived from either severance taxes (both production and conservation taxes, the latter being very small) or royalties.

Nearly all oil revenues accrue from the North Slope. The very mature Cook Inlet fields are relatively insignificant from a revenue standpoint.

The petroleum-production revenue-forecasting model is designed to calculate oil and gas severance taxes and royalty payments due the state each year under provisions of existing state laws and contracts. The North Slope component is a simulation model that generates a wide range of potential revenue outcomes for individual fields for each of the next 50 years. This model is structured to illustrate the uncertainty inherent in forecasting by producing distributions of outcomes rather than single point estimates. The most variable input components are production volume and price.

The North Slope is dominated by the Prudhoe Bay field. In FY 1986, the Prudhoe Bay field accounted for 90% of North Slope production and revenue; the balance was attributed to the Kuparuk field, with minor amounts from Milne Point (which was shut down recently for economic reasons). Lisburne recently began production and Endicott is expected to begin in early 1988.

As Prudhoe Bay begins to decline in the next 1 to 3 years, it will become relatively less significant (although it is still expected to dominate North Slope production through this century), and other fields will become more important.

Exploration in recent years has revealed the existence of several other North Slope accumulations. These include West Suk, Seal Island, Sandpiper, Northstar, Point Thomson, and one in the Colville Delta. Production decisions

on these fields are pending further geologic, engineering, and economic analyses. They are henceforth referred to as the "marginal fields."

To reduce the likelihood that the model will project revenue from uneconomical fields, we have developed a model that explicitly considers the economic feasibility of the marginal fields in the revenue forecasts. For all fields (including the existent ones), the model also makes projected production volume sensitive to projected price within the feasibility framework so that the optimal (profit-maximizing) value is produced.

Feasibility

Theoretical Framework. The main revenue-forecasting model uses Monte Carlo simulation. There are a myriad stochastic input variables, among them production volume and price. We have found that about 1,500 simulations of the future (passes or outcomes) are necessary for convergence, and the forecast is generated from the aggregation of the outcomes. Each outcome has a price and volume vector referred to as "sampled" prices and volumes.

The feasibility component to the main revenue-forecasting model works as follows.

1. A base-case cost scenario is developed for the most likely production volumes and earliest practical development for each field.
2. The main model independently samples for price and field production volume.
3. Costs for the sampled production volume are generated on the basis of cost functions, which relate the sampled production volume to the base-case volume and costs.
4. The economic rent (profit) for the sampled production volume and price vector is computed for the field. This is described in detail below.
5. If the economic rent for the sampled scenario is positive, development and production ensue at the earliest practical developmental time frame for the field, the optimal production level is found (see Optimal Production), and revenues are computed. (Positive economic rent equates to economic feasibility.) If the economic rent is negative, the decision on whether to develop and to

produce is delayed 1 year (to see whether future oil prices will be higher and to spur positive economic rent), and economic rent is recalculated. This process continues until either positive economic rent is generated or 50 years of delay fail to produce positive economic rent, in which case the field is not produced for that sampled scenario.

Computation of Economic Rent. As described, the revenue-forecasting model tests economic feasibility of marginal fields given the price/volume/cost relationships of simulated scenarios. A decision is made either to produce or not to produce a given volume, depending on positive or negative economic rent, and the first startup year that generates a positive economic rent is found. This section describes the computation of economic rent. Some of the components are germane only to Alaska.

Inputs. All prices and costs are in real 1986 U.S. dollars.

Schedule Inputs. The following inputs are entered by year, beginning with the first year any capital costs are incurred. The "year of decision" is Year 0. Historical years are negative. The current year may be 0 or historical if the year of decision is in the future.

- $(t_o)_{n_o}$ = year (n_o th year of field operation),
- P_{n_h} = Prudhoe Bay wellhead price [dollars per barrel at Pump Station 1 of the Trans-Alaskan Pipeline System (TAPS)] for Historical Year n_h , with n_{h0} being the current year (n_h will vary from n_o as the year of decision is pushed back),
- $(\Delta N_p)_{n_o}$ = production volume, millions of barrels per year,
- $(n_w)_{n_o}$ = producing wells, and
- $(C)_{n_o}$ = base-case capital cost, millions of dollars per year.

P , ΔN_p , and n_w are intermediate output from the main model.

Single-Value Inputs. See the description of model functioning for a detailed explanation of these inputs.

- i = real after-tax discount rate, percentage expressed as decimal,
- i_{RR} = royalty rate, percentage expressed as decimal,
- E_{ic} = transportation cost and quality differential to bring the Prudhoe Bay wellhead price back to the specific field's wellhead, dollars per barrel,
- E'_{ic} = actual variable operating cost of transportation, dollars per barrel,
- C_f = field costs, dollars per barrel,
- i_{ST} = severance tax rate, percentage expressed as decimal,
- E_{OD} = direct operating cost (includes only production supplies, purchased fuels, routine maintenance, and labor), dollars per barrel,
- C_{fix} = proportion of capital costs fixed, percentage expressed as decimal,
- C_{var} = proportion of capital costs variable, percentage expressed as decimal,

- ΔN_{pp} = peak production volume for base case, millions of barrels per year,
- E_{of} = proportion of operating cost fixed, percentage expressed as decimal,
- E_{ov} = proportion of operating cost variable, percentage expressed as decimal,
- E_{oEP} = per-barrel operating cost at peak production volume for base case,
- C_{IDC} = intangible portion of capital investment, percentage expressed as decimal,
- E_B = total lease bonuses, millions of dollars,
- i_{ST} = state corporate income tax rate, percentage expressed as decimal, and
- i_{fT} = federal corporate income tax rate, percentage expressed as decimal.

Model Functions. The feasibility model uses discounted cash flows to compute economic rent on an equivalent amortized per-barrel and field basis for a particular volume/price/cost scenario. The model operates in a spread-sheet format. The output columns defined in terms of the previously defined inputs are as follows.

The year is given as

$$t = (t_o)_{n_o}$$

The discount factor for Year n_o , $(F_D)_{n_o}$, is expressed by

$$(F_D)_{n_o} = \frac{1}{(1+i)^t}$$

The Prudhoe Bay wellhead price, P , is defined by

$$P = P_{n_h} + (\Delta E_{TV})_{n_h}$$

where ΔE_{TV} is the change in the TAPS tariff that results from a change in throughput. (See the Appendix.)

Production volume is defined as

$$\Delta N_p = (\Delta N_p)_{n_o}$$

Discounted production volume is expressed by

$$\Delta N_{pPV} = \Delta N_p [(F_D)_{n_o}]$$

Gross revenue is defined by

$$I_g = P \Delta N_p$$

Royalty, i_R , is defined by

$$i_R = \Delta N_p [i_{RR}(P - E_{ic} - C_f)]$$

where E_{ic} is the transportation cost and quality differential to bring the Prudhoe Bay wellhead price back to the specific field's wellhead and accounts for taxes, operating cost, rate of return, and depreciation in an environment where the producer is also operating the pipeline, and the gross revenue requirements for deriving the institutional tariff are front-loaded. Royalties and both severance and income taxes are based on E_{ic} . E'_{ic} is based on the gross revenue requirement to a third-party operator and is used to calculate the real economic cost of transportation. C_f , the field cost, is a deduction for computing

wellhead value for royalties, and includes dehydration, cleaning, and gathering. There is a floor of zero for royalties.

Discounted royalty is defined by

$$i_{RPV} = i_R [(F_D)_{n_o}].$$

Severance tax is expressed by

$$i_{ST} = \Delta N_p (1 - i_{RR}) \{ F_{EL} i_{ST} [P - E_{IC} + (i_{RR} C_f)] \},$$

where F_{EL} is the statutory economic limit factor reduce the severance tax rate as well productivity declines.

$$F_{EL} = q_{ELB} \left(\frac{460}{q_{EL}} \right),$$

where

$$q_{ELB} = \left\{ \frac{[(\Delta N_p) 1,000,000] / [365(n_w)_{n_o}]}{-q_{EL}} \right\} / \left\{ \frac{[(\Delta N_p) 1,000,000] / [365(n_w)_{n_o}]}{}$$

and

$$q_{EL} = \left\{ \frac{[E_{OD} - (i_{RR} C_f)] [(\Delta N_p) 1,000,000] / 365}{(P - E_{IC})} \right\} / (n_w)_{n_o}.$$

There is a floor of 300 B/D [48 m³/d] per well for q_{EL} . There is a floor of zero for F_{EL} . For the first 10 years of a field, if $F_{EL} > 0.7$, $F_{EL} = 1.0$.

The severance tax rate is reduced 22.5% for the first 5 years of a field. There is a statutory floor of \$0.80/bbl [55.03/m³] (nominal) for the $i_{ST} [P - E_{IC} + (i_{RR} C_f)]$ portion of the calculation. There is a floor of zero for the severance tax.

Discounted severance tax is defined by

$$i_{STPV} = i_{ST} [(F_D)_{n_o}].$$

Capital costs are expressed by

$$C = \{ C_{fix} [(C)_{n_o}] \} + \left\{ C_{var} [(C)_{n_o}] \sqrt{\frac{\Delta N_{psv}}{\Delta N_{pp}}} \right\},$$

where ΔN_{psv} is the peak production volume for a sampled production volume vector.

Discounted capital costs are defined by

$$C_{PV} = C [(F_D)_{n_o}].$$

Operating costs cover all expenses incurred in lifting oil to the surface and in gathering, treating, field-processing, and field storage. This includes workovers, field engineering, dehydration, cleaning, conditioning, labor, fuel, insurance, repairs, and maintenance, as well as general, administration, and overhead costs. Operating costs are expressed as

$$E_o = (E_{oF} E_{oEP} \Delta N_{pp}) + (E_{ov} E_{oEP} \Delta N_p).$$

Discounted operating costs are defined by

$$E_{oPV} = E_o [(F_D)_{n_o}].$$

Property tax is expressed by

$$E_{PT} = \sum_{n_o=1}^n [C(1 - C_{DC})] (0.02) \left[\frac{(t_a - t)}{(t_a - n_o)} \right],$$

where

n_o = year expenditure was incurred.

n = number of years over which expenditures were incurred.

t_a = final year of production, and

t = subject year.

The property tax is 2% of the undepreciated tangible assets based on straight-line depreciation.

Discounted property tax is defined by

$$E_{PTPV} = E_{PT} [(F_D)_{n_o}].$$

Bonus depletion is expressed by

$$D_I = E_B (\Delta N_p / \Sigma \Delta N_p).$$

Before-tax state net revenue is given by

$$I_{NRs} = I_g - [i_R + i_{ST} + E_{PT} + (E_{IC} \Delta N_p)].$$

State tax depreciation is expressed as

$$D_{rs} = \sum_{n_o=1}^n C \left(\frac{\Delta N_p}{N_{pl}} \right),$$

where

n_o = year expenditure was incurred.

n = number of years over which expenditures were incurred, and

N_{pl} = amount of production after asset comes on line.

This is a units-of-production depreciation.

Total state deductions are given by

$$D_{ds} = E_o + D_I + D_{rs}.$$

State taxable income is expressed by

$$I_{sT} = I_{NRs} - D_{ds}.$$

State corporate income tax is given as

$$E_{sIT} = i_{sIT} I_{sT},$$

where i_{sIT} , the corporate income tax rate, represents the product of the historical average proportion of worldwide net income realized in Alaska and the marginal tax rate. There is a floor of zero for the tax.

Discounted state corporate income tax is defined by

$$E_{sITPV} = E_{sIT} [(F_D)_{n_o}].$$

TABLE 1—FIELD XXX INPUTS

t_o (year)*	Schedule Inputs				Single Value Inputs	
	P (dollars/bbl)	ΔN_p (10^6 bbl)	n_w (number)	C (\$1 million)		
0	23.00	0	0	0	I	0.08
1	23.10	0	0	0	I_{RR}	0.125
2	23.20	0	0	0	E_{ST}	2.56
3	23.30	0	0	341	E_{PT}	1.29
4	23.40	0	0	341	C_I	0.70
5	23.50	11	33	431	I_{ST}	0.15
6	23.60	20	51	68	E_{OO}	1.20
7	23.70	19	45	0	C_{RR}	0.1
8	23.80	19	45	0	C_{VW}	0.9
9	23.90	19	45	0	ΔN_{DP}	26
10	24.00	19	45	0	E_{OP}	0.33
11	24.10	19	45	0	E_{VP}	0.67
12	24.20	19	45	0	E_{DOP}	2.14
13	24.30	14	42	0	C_{IDC}	0.50
14	24.40	11	38	0	E_B	100
15	24.50	9	33	0	i_{MT}	0.014
16	24.60	7	28	0	i_{IT}	0.34
17	24.70	5	25	0		
18	24.80	4	23	0		
19	24.90	3	20	0		
20	25.00	3	18	0		
21	25.10	2	14	0		
22	25.20	1	11	0		
23	25.30	1	9	0		
24	25.40	1	7	0		
25	25.50	1	5	0		
26	25.60	1	5	0		
27	25.70	1	5	0		
28	25.80	1	5	0		

*Year 0 is 1986.

Before-tax federal net revenue is expressed by

$$I_{NRF} = I_g - [i_R + i_{ST} + E_{PT} + E_{iIT} + (E_{IC} \Delta N_p)].$$

Windfall profits tax is given as

$$E_{WPT} = \Delta N_p (P - 17.44) (1 - i_{RR}) (1 - i_{ST}) (0.7),$$

where 17.44 is the base-case price in 1986 dollars. This applies to the Prudhoe Bay field only. The tax expires after 1993.

Discounted windfall profits tax is defined by

$$E_{WPTPV} = E_{WPT} [(F_D)_{n_o}].$$

Intangible capital costs are given by

$$C_{IDC} = C_{IDC} \times C \times 0.7.$$

Federal tax depreciation is expressed by

$$D_{rf} = \sum_{n_o=1}^n \{ [C(1 - C_{IDC})]_{n_o} \} F_{DR},$$

where

- n_o = year expenditure was incurred,
- n = number of years over which expenditures were incurred,
- t = subject year, and

$$F_{DR} = \begin{cases} 0.35 & \text{if } t - n_o = 0, \\ 0.26 & \text{if } t - n_o = 1, \\ 0.21 & \text{if } t - n_o = 2, \\ 0.16 & \text{if } t - n_o = 3, \\ 0.13 & \text{if } t - n_o = 4, \\ 0.05 & \text{if } t - n_o = 5, \\ 0.14 & \text{if } t - n_o = 6, \text{ and} \\ 0 & \text{if } t - n_o > 6. \end{cases}$$

The federal tax depreciation is a 200% double-declining-balance 7-year accelerated-depreciation schedule, which also includes the appropriate depreciation of intangibles.

Total federal deductions are given by

$$D_{df} = E_o + D_I + E_{WPT} + C_{IDC} + D_{rf}.$$

Federal taxable income is expressed by

$$I_{JT} = I_{NRF} - D_{df}.$$

There is no floor for federal income tax because losses can be offset against other worldwide income. Federal income tax is defined by

$$E_{JT} = i_{JT} I_{JT}.$$

Discounted federal income tax is expressed by

$$E_{JTPV} = E_{JT} [(F_D)_{n_o}].$$

TABLE 2—FIELD XXX ECONOMIC RENT

t (year)	P (dollars/bbl)	ΔN_p (10^6 bbl)	ΔN_{DPV} (10^6 bbl)	I_p (\$1 million)	I_R (\$1 million)	I_{DPV} (\$1 million)	I_{ST} (\$1 million)	I_{STPV} (\$1 million)	C (\$1 million)	C_{PV} (\$1 million)	E_0 (\$1 million)	E_{DPV} (\$1 million)	E_{ST} (\$1 million)	E_{STPV} (\$1 million)	D_t (\$1 million)
0	23.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	23.10	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	23.20	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	23.30	0	0	0	0	0	0	0	303	240	0	0	3	2	0
4	23.40	0	0	0	0	0	0	0	303	222	0	0	6	4	0
5	23.50	11	7	259	28	19	13	9	383	281	33	22	9	6	5
6	23.60	20	13	472	51	32	27	17	59	37	47	30	10	6	10
7	24.00	19	11	458	49	29	26	18	0	0	45	28	9	5	9
8	24.04	19	10	457	49	27	26	15	0	0	45	25	9	5	9
9	24.10	19	10	458	49	25	28	14	0	0	45	23	8	4	9
10	24.27	19	9	461	50	23	34	16	0	0	45	21	8	4	9
11	24.29	19	8	462	50	21	34	15	0	0	45	19	7	3	9
12	24.42	19	8	464	50	20	35	14	0	0	45	18	7	3	9
13	24.55	14	5	344	37	14	22	8	0	0	37	14	6	2	7
14	24.68	11	4	271	29	10	15	5	0	0	33	11	6	2	5
15	24.77	9	3	223	24	6	12	4	0	0	29	9	5	2	4
16	24.88	7	2	174	19	6	9	2	0	0	26	8	5	1	3
17	24.99	5	1	125	14	4	4	1	0	0	23	6	4	1	2
18	25.13	4	1	101	11	3	3	1	0	0	21	5	4	1	2
19	25.29	3	1	76	8	2	1	0	0	0	20	5	3	1	1
20	25.48	3	1	76	8	2	2	0	0	0	20	4	3	1	1
21	25.68	2	0	51	6	1	1	0	0	0	18	4	2	0	1
22	25.88	1	0	26	3	1	0	0	0	0	17	3	2	0	0
23	26.13	1	0	26	3	0	0	0	0	0	17	3	1	0	0
24	26.54	1	0	27	3	0	0	0	0	0	17	3	1	0	0
25	27.27	1	0	27	3	0	1	0	0	0	17	2	0	0	0
26	26.59	1	0	27	3	0	1	0	0	0	17	2	0	0	0
27	25.70	1	0	26	3	0	1	0	0	0	17	2	0	0	0
Total		209	94	5,087	551	248	299	139	1,047	760	679	265	119	55	100

TABLE 2—FIELD XXX ECONOMIC RENT (continued)

I_{NR} (\$1 million)	D_{NR} (\$1 million)	D_{DZ} (\$1 million)	I_{ST} (\$1 million)	E_{ST} (\$1 million)	E_{STPV} (\$1 million)	I_{NR} (\$1 million)	E_{WPT} (\$1 million)	E_{WPTPV} (\$1 million)	C_{IOC} %	D_{NR} (\$1 million)	D_{DZ} (\$1 million)	I_{ST} (\$1 million)	E_{ST} (\$1 million)	E_{STPV} (\$1 million)
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
-3.0	0.0	0.0	-3.0	0	0	-3	0.00	0.00	106	53	159	-162	-55	-44
-5.9	0.0	0.0	-5.9	0	0	-6	0.00	0.00	106	92	198	-204	-69	-51
179.6	52.3	90.1	89.5	1	1	178	0.00	0.00	134	138	310	-132	-45	-30
332.9	101.0	157.5	175.4	2	2	330	0.00	0.00	21	116	193	137	47	29
321.3	95.9	150.4	171.0	2	1	319	0.00	0.00	0	92	146	173	59	34
322.5	95.9	150.4	172.1	2	1	320	0.00	0.00	0	64	118	202	89	37
323.8	95.9	150.4	173.5	2	1	321	0.00	0.00	0	58	113	209	71	35
320.5	95.9	150.4	170.2	2	1	318	0.00	0.00	0	35	89	229	78	38
321.4	95.9	150.4	171.0	2	1	319	0.00	0.00	0	28	83	236	80	34
323.8	95.9	150.4	173.5	2	1	321	0.00	0.00	0	4	59	263	89	35
242.3	70.7	114.7	127.5	2	1	240	0.00	0.00	0	0	44	196	67	25
192.5	55.5	93.4	99.1	1	0	191	0.00	0.00	0	0	38	153	52	18
158.4	45.4	79.1	79.3	1	0	157	0.00	0.00	0	0	34	124	42	13
124.0	35.3	64.9	59.2	1	0	123	0.00	0.00	0	0	30	94	32	9
89.9	25.2	50.6	39.2	1	0	89	0.00	0.00	0	0	25	64	22	6
72.9	20.2	43.5	29.4	0	0	72	0.00	0.00	0	0	23	49	17	4
55.4	15.1	36.4	19.0	0	0	55	0.00	0.00	0	0	21	34	12	3
55.7	15.1	36.4	19.4	0	0	55	0.00	0.00	0	0	21	34	12	2
37.5	10.1	29.2	8.3	0	0	37	0.00	0.00	0	0	19	18	6	1
18.6	5.0	22.1	-3.6	0	0	19	0.00	0.00	0	0	17	1	1	0
19.3	5.0	22.1	-2.9	0	0	19	0.00	0.00	0	0	17	2	1	0
19.8	5.0	22.1	-2.4	0	0	20	0.00	0.00	0	0	17	3	1	0
20.3	5.0	22.1	-1.9	0	0	20	0.00	0.00	0	0	17	3	1	0
20.2	5.0	22.1	-1.9	0	0	20	0.00	0.00	0	0	17	3	1	0
19.4	5.8	22.9	-3.5	0	0	19	0.00	0.00	0	0	17	2	1	0
3,582.9	1,052.6	1,831.5	1,751.4	25	12	3,558	0.00	0.00	366	600	1,826	1,732	58	199

C _{tot} , dollars/bbl	
C	8.07
E ₀	2.81
E _R	1.29
E _R	2.62
i _{ST}	1.47
E _{ST}	0.58
E _{ST}	0.12
E _{ST}	2.11
E _{ST}	0.00
Total	19.07
P ₀	24.80
E ₀	5.73
E ₀ , \$1 million	539.53
I ₀ , \$1 million	34.00

TABLE 3—FIELD XXX LOW-PRICE VECTOR

t	P	ΔN_B	ΔN_{BPV}	I_B	I_R	I_{BPV}	I_{ST}	I_{STPV}	C	C_{PV}	E_o	E_{OPV}	E_{ST}	E_{STPV}	D_t
(year)	(dollars/bbl)	(10 ⁶ bbl)	(10 ⁶ bbl)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)
0	15.25	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	15.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	15.75	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	16.00	0	0	0	0	0	0	0	303	240	0	0	3	2	0
4	16.25	0	0	0	0	0	0	0	303	222	0	0	6	4	0
5	16.50	11	7	182	18	12	9	8	383	281	33	22	9	6	5
6	16.75	20	13	335	34	21	19	12	59	37	47	30	10	6	10
7	17.00	19	11	323	33	19	19	11	0	0	45	28	9	5	9
8	17.25	19	10	328	33	18	19	10	0	0	45	25	8	5	9
9	17.50	19	10	333	34	17	19	10	0	0	45	23	8	4	9
10	17.98	19	9	342	35	18	24	11	0	0	45	21	7	3	9
11	18.37	19	8	349	36	15	25	11	0	0	45	19	7	3	9
12	18.83	19	8	358	37	15	25	10	0	0	45	18	6	3	9
13	18.99	14	5	268	28	10	16	8	0	0	37	14	5	2	7
14	19.17	11	4	211	22	7	12	4	0	0	33	11	5	2	5
15	19.38	9	3	174	18	8	9	3	0	0	29	9	5	2	4
16	19.54	7	2	137	14	4	6	2	0	0	26	8	4	1	3
17	19.74	5	1	99	10	3	3	1	0	0	23	6	4	1	2
18	19.93	4	1	80	8	2	2	1	0	0	21	5	3	1	2
19	21.60	3	1	65	7	2	1	0	0	0	20	5	3	1	1
20	21.77	3	1	85	7	1	1	0	0	0	20	4	2	0	1
21	21.77	2	0	44	5	1	1	0	0	0	18	4	2	0	1
22	21.77	1	0	22	2	0	0	0	0	0	17	3	1	0	0
23	21.77	1	0	22	2	0	0	0	0	0	17	3	1	0	0
24	21.77	1	0	20	2	0	0	0	0	0	17	3	0	0	0
25	21.77	1	0	20	2	0	1	0	0	0	17	2	0	0	0
Total		207	94	3,772	388	172	213	98	1,047	760	646	261	109	52	99

TABLE 3—FIELD XXX LOW-PRICE VECTOR (continued)

I_{NB}	D_{NB}	D_{BPV}	I_{ST}	E_{ST}	E_{STPV}	I_{WP}	E_{WPT}	E_{WPTPV}	C_{DGC}	D_A	D_G	I_{IT}	E_{IT}	E_{ITPV}
(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	%	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)	(\$1 million)
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
-3.0	0.0	0.0	-3.0	0	0	-3	0.00	0.00	106	53	159	-162	-55	-44
-5.9	0.0	0.0	-5.9	0	0	-6	0.00	0.00	106	92	198	-204	-69	-51
116.7	92.7	92.7	24.0	0	0	116	0.00	0.00	134	138	310	-194	-66	-45
222.0	162.6	162.6	59.4	1	1	221	0.00	0.00	21	116	193	28	10	6
214.1	155.2	155.2	58.8	1	0	213	0.00	0.00	0	92	146	87	23	13
218.4	155.2	155.2	63.2	1	0	218	0.00	0.00	0	64	118	99	34	18
222.8	155.2	155.2	67.6	1	0	222	0.00	0.00	0	58	113	109	37	19
226.1	155.2	155.2	70.9	1	0	225	0.00	0.00	0	35	89	138	48	21
232.6	155.2	155.2	77.4	1	0	232	0.00	0.00	0	28	83	149	51	22
240.1	155.2	155.2	84.9	1	0	239	0.00	0.00	0	4	59	180	61	24
180.2	118.3	118.3	61.9	1	0	179	0.00	0.00	0	0	44	135	48	17
143.9	96.2	96.2	47.7	1	0	143	0.00	0.00	0	0	38	105	38	12
119.2	81.4	81.4	37.8	1	0	119	0.00	0.00	0	0	34	85	29	9
93.9	66.7	66.7	27.3	0	0	94	0.00	0.00	0	0	30	64	22	8
68.5	51.9	51.9	16.6	0	0	68	0.00	0.00	0	0	25	43	15	4
56.0	44.5	44.5	11.4	0	0	56	0.00	0.00	0	0	23	32	11	3
48.8	37.1	37.1	9.4	0	0	48	0.00	0.00	0	0	21	25	9	2
47.1	21.2	21.2	25.9	0	0	47	0.00	0.00	0	0	21	25	9	2
31.7	19.2	19.2	12.5	0	0	31	0.00	0.00	0	0	19	12	4	1
15.8	17.1	17.1	-1.2	0	0	16	0.00	0.00	0	0	17	-1	0	0
16.4	17.1	17.1	-0.7	0	0	16	0.00	0.00	0	0	17	-1	0	0
14.9	17.1	17.1	-2.2	0	0	15	0.00	0.00	0	0	17	-2	-1	0
14.4	17.1	17.1	-2.7	0	0	14	0.00	0.00	0	0	17	-3	-1	0
2,532.5	1,046.8	1,791.5	740.9	11	5	2,522	0.00	0.00	366	680	1,792	730	248	40

C_{eq} , dollars/bbl

C	8.09
E_o	2.78
E_{IC}	1.29
E_{IR}	1.83
I_{ST}	1.04
E_{ST}	0.55
E_{STPV}	0.05
E_{IT}	0.42
E_{ITPV}	0.00
Total	16.05
P _{eq}	16.48
E_{IT}	0.43
E_{IT} , \$1 million	40.30
I_{AB} , \$1 million	34.00

The equivalent amortized per-barrel cost by category is the sum of the discounted costs divided by the sum of the discounted volume:

$$C = \Sigma C_{PV} / \Sigma \Delta N_{pPV},$$

$$E_o = \Sigma E_{oPV} / \Sigma \Delta N_{pPV},$$

$$i_R = \Sigma i_{RPV} / \Sigma \Delta N_{pPV},$$

$$i_{ST} = \Sigma i_{STPV} / \Sigma \Delta N_{pPV},$$

$$E_{PT} = \Sigma E_{PTPV} / \Sigma \Delta N_{pPV},$$

$$E_{sIT} = \Sigma E_{sITPV} / \Sigma \Delta N_{pPV},$$

$$E_{jIT} = \Sigma E_{jITPV} / \Sigma \Delta N_{pPV}, \text{ and}$$

$$E_{WPT} = \Sigma E_{WPTPV} / \Sigma \Delta N_{pPV}.$$

The total equivalent amortized per-barrel cost is expressed as

$$C_{ca} = [(\Sigma i_{RPV} + \Sigma i_{STPV} + \Sigma C_{PV} + \Sigma E_{oPV} + \Sigma E_{PTPV} + \Sigma E_{sITPV} + \Sigma E_{jITPV} + \Sigma E_{WPTPV}) / \Sigma \Delta N_{pPV}] + E'_{ic}.$$

The value of C_{ca} in this calculation excludes sunk costs. Feasibility is impervious to these costs when it is sunk. The model also ignores exploration costs. These are largely intangible and are deducted as incurred.

The equivalent amortized per-barrel price is defined by

$$P_{ca} = \Sigma [(P + P_p) \Delta N_{pPV}] / \Sigma \Delta N_{pPV},$$

where P_p is the TAPS operating profit. (See the Appendix.)

The equivalent amortized per-barrel economic rent is expressed by

$$E_r = P_{ca} - C_{ca}.$$

Shutdown and Feasibility. To find the shutdown year, the model initially forms a 50-year spread-sheet and cuts off production the first year after decline, where the after-tax net value, $(P + P_p) \Delta N_p - [i_R + i_{ST} + E_o + E_{PT} + E_{sIT} + E_{jIT} + (\Delta N_p E'_{ic})]$, is negative. Because depreciation, property taxes, and the bonus depletion depend on the life of the field (and the final year), the model forms a spread-sheet on the basis of the preliminary last year and finds a second preliminary last year on the basis of the above criteria. Economic rent is checked. If economic rent is negative, development is lagged a year, and the process starts again. If economic rent is positive, the "definitive" last year is found by a comparison of the expected remaining after-tax net present value with the tax-write-off value of abandonment.

To repeat, the preliminary shutdown point is the first year after decline, where the after-tax net value is negative. The model tests to see whether abandonment should occur earlier. If the value of the immediate tax write-offs of the depreciable and depletable items (the undepreciated assets and the undepleted bonus) exceeds the expected remaining after-tax net present value, it is advantageous to abandon the field and to write off the former amounts against other worldwide operations.

Each year, the model looks at the remaining years and asks whether the subject year should be the final year. Each successive year, the model computes the expected after-tax net present value of the remaining years, I_{PVAT} , and computes the tax write-off value of abandonment, I_{AB} (the product of the federal tax rate and the undepreciated capital and undepleted bonus), for that year. If $I_{PVAT} > I_{AB}$, production occurs and the question is asked next year. If $I_{AB} > I_{PVAT}$, the subject year becomes the last year. This criterion is also used for the existent fields.

Once the definitive last year is found, economic rent is checked again. If it is negative, development is lagged a year and the process starts again. If it is positive and development has been lagged, the process is consummate. If it is positive and development has not been lagged, examination of EOR begins.

The model also compares the total economic rent of development, $\Sigma \Delta N_{pPV} E_r$, with the value in decreased federal income taxes of writing off lease bonuses, $0.34 E_B$, as an additional feasibility check.

Example. Table 1 shows a sample input for Hypothetical Field XXX. Table 2 shows the ensuing economic rent calculation. Note that the economic rent is positive (\$5.73/bbl [\$36.04/m³]), so the field is produced at the earliest practical time.

If we enter a lower price vector—e.g., starting at \$8.00/bbl [\$50.32/m³] in 1987—and increase it by \$0.25/bbl [\$1.57/m³] a year, with all other inputs the same, we will obtain the results shown in Table 3.

Economic rent is initially negative and the development decision is thus postponed year by year until a positive economic rent is eventually generated after 29 years of delay. Year 0, the year the decision is made on whether to start development, is 2016.

Optimal Production

The feasibility procedure makes a decision either to produce or not to produce a given volume, depending on positive or negative economic rent, and solves for the first startup year, which generates a positive economic rent.

When startup does not occur in the earliest practical time frame, economic rents are small when startup does occur, and there is little incentive to expand production at increasing marginal costs. In addition, as the input volume scenarios represent primary production, there is little incentive to reduce production at decreasing marginal costs.

When startup occurs at the earliest practical time (for the existent fields as well), however, economic rents are generally large, and marginal revenues exceed marginal costs, which suggests that there will be a major incentive to increase production to where marginal costs equal marginal revenues. This implies the evaluation of investment in EOR (secondary or tertiary, depending on what has actually occurred in the field).

To find the optimal amount of added production given the sampled (or input) primary price/cost/volume vectors, volume is increased in increments and the marginal revenue and marginal cost are compared. This is called an "increment cycle." If marginal revenue exceeds marginal cost, volume is increased again, and marginal revenue and cost are compared again (another increment cycle). This continues until marginal revenue equals marginal cost, at which point there is optimal production

TABLE 4—FIELD XXX FIRST INCREMENT CYCLE

t (year)	P (dollars/bbl)	ΔN_p (10^4 bbl)	ΔN_{pPV} (10^4 bbl)	I_p (\$1 million)	I_R (\$1 million)	I_{STPV} (\$1 million)	I_{ST} (\$1 million)	I_{STPV} (\$1 million)	C (\$1 million)	C_{PV} (\$1 million)	E_o (\$1 million)	E_{oPV} (\$1 million)	E_{ST} (\$1 million)	E_{STPV} (\$1 million)	D_i (\$1 million)
0	23.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	23.10	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	23.20	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	23.30	0	0	0	0	0	0	0	303	240	0	0	3	2	0
4	23.40	0	0	0	0	0	0	0	303	222	0	0	6	4	0
5	23.50	11	7	259	28	19	13	9	383	261	33	22	9	6	5
6	23.60	20	13	472	51	32	27	17	59	37	47	30	10	6	9
7	24.00	19	11	458	49	29	28	16	0	0	45	26	9	5	9
8	24.04	19	10	457	49	27	28	15	0	0	45	25	9	5	9
9	24.10	19	10	458	49	25	28	14	0	0	45	23	8	4	9
10	24.27	19	9	461	50	23	34	16	17	8	45	21	8	4	9
11	24.29	19	8	462	50	21	34	15	17	7	45	19	8	3	9
12	24.42	20	8	480	52	21	36	14	0	0	47	19	7	3	9
13	24.55	15	5	358	39	14	24	9	0	0	39	14	7	2	7
14	24.66	11	4	284	31	10	17	6	0	0	34	11	6	2	5
15	24.77	9	3	234	25	8	13	4	0	0	30	10	6	2	4
16	24.88	7	2	184	20	6	10	3	0	0	27	8	5	2	3
17	24.99	5	1	133	14	4	5	1	0	0	24	6	5	1	2
18	25.13	4	1	108	12	3	3	1	0	0	22	6	4	1	2
19	25.29	3	1	82	9	2	2	0	0	0	20	5	4	1	2
20	25.46	3	1	82	9	2	2	0	0	0	20	4	3	1	1
21	25.66	2	0	55	6	1	1	0	0	0	19	4	3	1	1
22	25.88	1	0	30	3	1	0	0	0	0	17	3	2	0	1
23	26.13	1	0	30	3	1	0	0	0	0	17	3	2	0	1
24	26.54	1	0	30	3	1	1	0	0	0	17	3	1	0	1
25	27.27	1	0	30	3	0	1	0	0	0	17	3	1	0	1
26	26.59	1	0	29	3	0	1	0	0	0	17	2	0	0	1
27	25.70	1	0	28	3	0	1	0	0	0	17	2	0	0	1
Total		213	96	5,199	563	250	310	142	1,082	776	692	268	128	57	100

TABLE 4—FIELD XXX INCREMENT STYLE (continued)

I_{NPS} (\$1 million)	D_{rs} (\$1 million)	D_{cs} (\$1 million)	I_{ST} (\$1 million)	E_{ST} (\$1 million)	E_{STPV} (\$1 million)	I_{NPS} (\$1 million)	E_{NPS} (\$1 million)	E_{NPSPV} (\$1 million)	C_{LOC} %	D_{rs} (\$1 million)	D_{cs} (\$1 million)	I_{ST} (\$1 million)	E_{ST} (\$1 million)	E_{STPV} (\$1 million)
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
-3.0	0.0	0.0	-3.0	0	0	-3	0.00	0.00	108	53	159	-162	-55	-44
-5.9	0.0	0.0	-5.9	0	0	-8	0.00	0.00	108	92	198	-204	-69	-51
179.6	50.9	88.8	90.9	1	1	178	0.00	0.00	134	138	310	-132	-45	-30
332.9	98.4	154.7	178.2	2	2	330	0.00	0.00	21	116	193	138	47	29
321.3	93.4	147.7	173.6	2	1	319	0.00	0.00	0	92	146	173	59	34
322.4	93.4	147.7	174.7	2	1	320	0.00	0.00	0	64	118	202	69	37
323.7	93.4	147.7	176.0	2	1	321	0.00	0.00	0	58	113	209	71	35
320.3	98.1	150.3	169.9	2	1	318	0.00	0.00	6	38	98	220	75	35
320.9	99.2	153.4	167.5	2	1	319	0.00	0.00	6	34	94	225	78	33
334.3	102.7	158.7	175.8	2	1	332	0.00	0.00	0	8	64	288	91	36
251.4	78.1	121.5	129.8	2	1	250	0.00	0.00	0	3	49	201	68	25
200.3	60.0	99.1	101.2	1	0	199	0.00	0.00	0	3	42	157	53	18
185.2	49.2	84.0	81.2	1	0	164	0.00	0.00	0	2	36	128	43	14
129.9	38.5	69.0	60.9	1	0	129	0.00	0.00	0	2	32	97	33	10
94.9	27.8	54.0	40.9	1	0	94	0.00	0.00	0	1	27	87	23	8
77.3	22.3	46.5	30.9	0	0	77	0.00	0.00	0	0	24	53	18	4
59.2	16.9	38.9	20.3	0	0	59	0.00	0.00	0	0	22	37	13	3
59.0	16.8	38.7	20.3	0	0	59	0.00	0.00	0	0	22	37	12	3
40.4	11.4	31.2	9.2	0	0	40	0.00	0.00	0	0	20	20	7	1
21.3	6.0	23.7	-2.4	0	0	21	0.00	0.00	0	0	18	4	1	0
21.5	5.9	23.8	-2.2	0	0	21	0.00	0.00	0	0	18	4	1	0
21.5	5.8	23.5	-2.0	0	0	22	0.00	0.00	0	0	18	4	1	0
21.7	5.8	23.4	-1.7	0	0	22	0.00	0.00	0	0	18	4	1	0
21.3	5.7	23.3	-2.0	0	0	21	0.00	0.00	0	0	18	4	1	0
20.8	5.6	23.3	-2.5	0	0	21	0.00	0.00	0	0	18	3	1	0
3,652.0	1,081.6	1,872.9	1,779.2	25	12	3,627	0.00	0.00	379	703	1,873	1,754	596	200

C_{loc} , dollars/bbl

C	8.12
E_o	2.81
E_c	1.29
E_R	2.62
I_{ST}	1.48
E_{ST}	0.60
E_{STPV}	0.12
E_{NPS}	2.09
E_{NPSPV}	0.00
Total	19.14
P_{∞}	24.81
E_c	5.67
E_{NPS} , \$1 million	541.72
I_{AB} , \$1 million	34.00

TABLE 5—FIELD XXX OPTIMAL PRODUCTION

t (year)	P (dollars/bbl)	ΔN_p	ΔN_{pv}	i_p	i_s	i_{pv}	i_{st}	i_{stpv}	C	C_{pv}	E_p	E_{pv}	E_{st}	E_{stpv}	D_t
		(10 ⁶ bbl)	(10 ⁶ bbl)	(\$ million)	(\$ million)	(\$ million)	(\$ million)	(\$ million)							
0	23.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	23.10	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	23.20	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	23.30	0	0	0	0	0	0	0	303	240	0	0	3	2	0
4	23.40	0	0	0	0	0	0	0	303	222	0	0	6	4	0
5	23.50	11	7	259	28	19	13	9	383	281	33	22	9	6	5
6	23.60	20	13	472	51	32	27	17	59	37	47	30	10	6	9
7	24.00	19	11	456	49	29	28	16	0	0	45	28	9	5	8
8	24.04	19	10	457	49	27	28	15	0	0	45	25	9	5	8
9	24.10	19	10	458	49	25	28	14	0	0	45	23	8	4	8
10	24.27	19	9	481	50	23	34	16	102	47	45	21	9	4	8
11	24.29	19	8	462	50	21	34	15	102	44	45	19	9	4	8
12	24.42	22	9	545	59	23	44	17	0	0	54	22	9	3	10
13	24.55	17	6	414	45	17	30	11	0	0	45	18	8	3	7
14	24.66	13	5	333	36	12	22	8	0	0	39	13	6	3	6
15	24.77	11	4	277	30	9	18	6	0	0	35	11	7	2	5
16	24.88	9	3	221	24	7	14	4	0	0	31	9	6	2	4
17	24.99	7	2	165	18	5	9	2	0	0	27	7	6	2	3
18	25.13	5	1	138	15	4	6	2	0	0	26	6	5	1	2
19	25.29	4	1	107	12	3	4	1	0	0	24	5	5	1	2
20	25.48	4	1	103	11	2	4	1	0	0	24	5	4	1	2
21	25.68	3	1	75	8	2	3	1	0	0	22	4	4	1	1
22	25.88	2	0	46	5	1	1	0	0	0	20	4	3	1	1
23	26.13	2	0	44	5	1	1	0	0	0	20	3	2	0	1
24	26.54	2	0	42	5	1	2	0	0	0	20	3	2	0	1
25	27.27	2	0	41	5	1	2	0	0	0	20	3	1	0	1
26	28.59	1	0	38	4	1	2	0	0	0	20	3	1	0	1
27	25.70	1	0	36	4	0	2	0	0	0	20	2	0	0	1
Total		231	101	5,647	612	264	358	156	1,251	851	732	284	142	62	100

volume. (An upper limit on EOR is set as an empirically estimated percentage of primary production. Limits are differentiated between secondary and tertiary recovery.)

As incremental production represents EOR, capital outlay begins after 5 years of primary production and extends over 2 years, after which incremental production begins. For example, if production in the base case begins in Year 5, capital costs for EOR occur in Years 10 and 11, and incremental production begins in Year 12.

Volume is incremented by adding production profile vectors of EOR. The size of the increment (the total amount of EOR added per increment—i.e., the sum of the vector) is set exogenously. Although in a strict marginal analysis only 1 bbl [0.16 m³] at a time should be added, larger increments do not materially sacrifice accuracy. We use the square root of ΔN_{psv} (see definition for C) for increment size.

The form ("shape") of the vector (decline curve) is given by

$$F_{erv} = \frac{(N_{per})_{t'}}{\sum_{t'=0}^{n_{sv}} (N_{per})_{t'}}$$

where

F_{erv} = percentage of total EOR per increment occurring in Year t ,

$$(N_{per})_{t'} = q_p / d^{t'}$$

q_p = peak production volume for sampled production volume vector, bbl/yr,

$$d = e^a$$

$$a = \ln(q_p / \Delta N_{pv}) / n_{sv}$$

ΔN_{pv} = volume in the last year of the sampled production volume vector that is greater than 1×10^6 bbl/yr [160×10^3 m³/a],

n_{sv} = number of years in sampled production volume vector from the peak year to the year ΔN_{pv} occurs, and

$t' = 0$ for peak year in sampled production volume vector or n_{sv} for the year ΔN_{pv} occurs.

Production is cut off when after-tax net value is negative, after which the marginal-revenue/marginal-cost test is performed.

An increasing marginal cost function has been posited with an exponential relationship between incremental volume and incremental cost:

$$C_{INC} = C_p \left[\left(\frac{\Delta N_{pINC} + \Delta N_{pP}}{\Delta N_{pP}} \right)^{(X+Z)} - 1 \right],$$

where

C_{INC} = incremental capital cost,

C_p = primary-case capital cost,

N_{pINC} = incremental volume, and

ΔN_{pP} = primary-case volume.

Empirical estimates have been made for X and Y for secondary and tertiary recovery.

$$Z = n_{INC} / [(F_{pul} \Delta N_{pP}) / s_i],$$

where

n_{INC} = increment number,

F_{pul} = percentage of primary production that is upper limit on EOR, and

s_i = size of increment.

TABLE 5—FIELD XXX OPTIMAL PRODUCTION (continued)

I_{NR} (\$1 million)	D_{n_1} (\$1 million)	D_{n_2} (\$1 million)	I_{ST} (\$1 million)	E_{ST} (\$1 million)	E_{STPV} (\$1 million)	I_{NW} (\$1 million)	E_{WPT} (\$1 million)	E_{WPTPV} (\$1 million)	C_{DOC} %	D_{n_1} (\$1 million)	D_{n_2} (\$1 million)	I_{ST} (\$1 million)	E_{ST} (\$1 million)	E_{STPV} (\$1 million)
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0	0	0
-3.0	0.0	0.0	-3.0	0	0	-3	0.00	0.00	108	53	159	-182	-55	-44
-5.9	0.0	0.0	-5.9	0	0	-6	0.00	0.00	108	92	198	-204	-69	-51
179.5	47.0	84.3	95.2	1	1	178	0.00	0.00	134	138	310	-131	-45	-30
332.9	90.7	148.4	186.5	3	2	330	0.00	0.00	21	118	193	138	47	30
321.3	86.2	139.8	181.5	3	1	319	0.00	0.00	0	92	145	173	59	34
322.4	86.2	139.8	182.6	3	1	320	0.00	0.00	0	84	118	202	69	37
323.7	86.2	139.8	183.9	3	1	321	0.00	0.00	0	58	112	209	71	36
319.4	99.7	153.3	166.1	2	1	317	0.00	0.00	36	52	142	175	60	28
319.3	115.3	168.9	150.4	2	1	317	0.00	0.00	36	59	149	168	57	25
378.5	135.5	199.4	177.1	2	1	374	0.00	0.00	0	28	92	282	96	38
288.1	102.5	154.4	133.6	2	1	286	0.00	0.00	0	19	71	215	73	27
232.3	81.9	126.7	105.6	1	1	231	0.00	0.00	0	15	60	171	58	20
193.0	67.7	107.7	85.3	1	0	192	0.00	0.00	0	9	49	143	49	15
154.0	53.8	89.0	65.1	1	0	153	0.00	0.00	0	10	45	108	37	11
116.1	40.2	70.5	45.5	1	0	115	0.00	0.00	0	7	37	78	26	7
95.8	32.8	60.7	35.1	0	0	95	0.00	0.00	0	0	28	67	23	6
75.4	25.6	51.1	24.4	0	0	75	0.00	0.00	0	0	25	50	17	4
73.1	24.8	50.0	23.1	0	0	73	0.00	0.00	0	0	25	47	16	3
52.8	17.7	40.7	12.1	0	0	53	0.00	0.00	0	0	23	30	10	2
32.8	10.9	31.5	1.3	0	0	33	0.00	0.00	0	0	21	12	4	1
31.2	10.2	30.8	0.4	0	0	31	0.00	0.00	0	0	21	11	4	1
30.0	9.7	30.2	-0.2	0	0	30	0.00	0.00	0	0	21	9	3	1
29.2	9.2	29.7	-0.5	0	0	29	0.00	0.00	0	0	20	9	3	0
27.7	8.8	29.2	-1.5	0	0	28	0.00	0.00	0	0	20	7	2	0
26.2	8.4	28.8	-2.0	0	0	26	0.00	0.00	0	0	20	6	2	0
3,943.5	1,250.8	2,102.7	1,840.8	26	12	3,918	0.00	0.00	438	813	2,103	1,815	617	200

C_{mar} , dollars/bbl

C	8.45
E_o	2.82
E_{nc}	1.29
E_{nc}	2.62
I_{ST}	1.55
E_{ST}	0.81
E_{ST}	0.12
E_{ST}	1.98
E_{WPT}	0.00
Total	19.45
P_{nc}	24.83
E_{nc}	5.38
E_{nc} , \$1 million	542.09
I_{AB} , \$1 million	34.00

Similarly, with operating costs,

$$(E_{oINC})_{n_o}$$

$$= (E_{oP})_{n_o} \left[\left(\frac{\Delta N_{pINC} + \Delta N_{pP}}{\Delta N_{pP}} \right)^{(Y+Z)} - 1 \right],$$

where $(E_{oINC})_{n_o}$ = incremental operating costs for Year n_o and $(E_{oP})_{n_o}$ = primary case operating costs for Year n_o .

Marginal revenue is expressed by

$$I_{mar} = \sum_{n_o = \Delta N_{pif}}^{\Delta N_{pil}} \{ [(\Delta N_{pPV})_{n_c} - (\Delta N_{pPV})_{n_c - 1}]_{n_o} \} \times \{ (P + P_p) + [(P + P_p)_d - (P + P_p)_{d-1}]_{n_o} \},$$

where

ΔN_{pif} = first year of incremental production,

ΔN_{pil} = last year of incremental production, and

n_c = subject increment cycle.

Marginal cost is defined by

$$C_{mar} = \{ \Sigma i_{RPV} + \Sigma i_{STPV} + \Sigma C_{PV} + \Sigma E_{oPV} + \Sigma E_{PTPV} + \Sigma E_{STPV} + \Sigma E_{WPTPV} + \Sigma E_{JTPV} + [(E'_{ic})_{n_c} \times \Sigma \Delta N_{pPV}] \}_{n_c} - \{ \Sigma i_{RPV} + \Sigma i_{STPV} + \Sigma C_{PV} + \Sigma E_{oPV} + \Sigma E_{PTPV} + \Sigma E_{STPV} + \Sigma E_{WPTPV} + \Sigma E_{JTPV} + [(E'_{ic})_{n_c - 1} \Sigma \Delta N_{pPV}] \}_{n_c - 1}.$$

Because the economic rent on Table 2 was positive at the earliest practical time frame, the model began to find the optimal amount of additional secondary recovery.

Table 4 shows the first increment cycle. This assumes $X=1.5$, $Y=1.5$, $n_{INC}=1$, $F_{pu}=0.42$, and $s_t = \sqrt{\Delta N_{pPV}}$. The incremental volume is 4 million bbl $[636 \times 10^3 \text{ m}^3]$. The marginal revenue is \$36 million, while the marginal cost is \$33 million. Because the marginal revenue exceeds the marginal cost, another increment cycle is added. This continues for six increment cycles until marginal revenue equals marginal cost, at which point 22 million bbl $[3.5 \times 10^6 \text{ m}^3]$ have been added (Table 5). At this point, total economic rent is maximized.

Conclusions

Forecasts of future production volumes must depend in part on the price environment. In lower-price scenarios, the development of marginal fields will be delayed and existing fields will be suspended until prices increase. In higher-price environments, additional EOR becomes attractive. A marginal cost function can solve for the optimal amount of incremental volume.

Nomenclature

C = capital or capital cost, \$1 million
 C_{ca} = equivalent amortized cost, dollars/bbl [dollars/m³]
 C_f = field cost, dollars/bbl [dollars/m³]
 C_{fix} = proportion of capital cost fixed, %
 C_{IDC} = intangible costs, %
 C_{INC} = incremental capital cost, \$1 million
 C_{mar} = marginal cost, \$1 million
 C_p = primary capital cost, \$1 million
 C_{PV} = discounted capital cost, \$1 million
 C_{var} = proportion of capital cost variable, %
 d = decline rate
 D_{df} = federal deductions, \$1 million
 D_{ds} = state deductions, \$1 million
 D_l = bonus depletion, \$1 million
 D_f = federal depreciation, \$1 million
 D_{rs} = state depreciation, \$1 million
 e = -2.71828
 E_B = total lease bonuses, \$1 million
 E_{FIT} = federal income tax, \$1 million
 E_{FITPV} = discounted federal income tax, \$1 million
 E_o = operating cost, \$1 million
 E_{oEP} = peak operating cost, \$1 million
 E_{of} = proportion of operating cost fixed, %
 E_{oINC} = incremental operating cost, \$1 million
 E_{oP} = primary operating cost, \$1 million
 E_{oPV} = discounted operating cost, \$1 million
 E_{ov} = proportion of operating cost variable, %
 E_{OD} = direct operating cost, \$1 million
 E_{PT} = property tax, \$1 million
 E_{PTPV} = discounted property tax, \$1 million
 E_r = economic rent, dollars/bbl [dollars/m³]
 E_{π} = total economic rent, \$1 million
 E_R = royalty, dollars, \$1 million
 E_{sIT} = state corporate income tax, \$1 million
 E_{sITPV} = discounted state corporate income tax, \$1 million
 E_{ic} = transportation cost, dollars/bbl [dollars/m³]
 E'_{ic} = actual transportation cost, dollars/bbl [dollars/m³]
 E_{Ta} = tariff, dollars/bbl [dollars/m³]
 E_{WPT} = windfall profits tax, \$1 million
 E_{WPTPV} = discounted windfall profits tax, \$1 million
 ΔE_{TV} = change in tariff from change in volume, dollars/bbl
 F_D = discount factor
 F_{DR} = depreciation factor

F_{erv} = form of enhanced recovery vector
 F_{EL} = economic limit factor
 F_{pul} = upper limit on EOR, %
 l = discount rate
 i_{FIT} = federal income tax rate
 i_R = royalty, \$1 million
 i_{RPV} = discounted royalty, \$1 million
 i_{RR} = royalty rate
 i_{sIT} = state income tax rate
 i_{ST} = severance tax, \$1 million
 i_{STPV} = discounted severance tax, \$1 million
 I_{AB} = tax value of abandonment, \$1 million
 I_{FT} = federal taxable income, \$1 million
 I_g = gross revenue, \$1 million
 I_{mar} = marginal revenue, \$1 million
 I_{NRf} = federal net revenue, \$1 million
 I_{NRs} = state net revenue, \$1 million
 I_{PVAT} = remaining after-tax net present value, \$1 million
 I_{sT} = state taxable income, \$1 million
 n = number of years over which expenditures were incurred
 n_c = subject increment cycle
 n_h = historical year
 n_{INC} = increment number
 n_o = year of operation
 n_{sv} = number of years in sampled production volume vector from the peak year to the year ΔN_{ply} occurs
 n_w = number of wells
 N_{per} = amount of EOR, 10⁶ bbl [10⁶ m³]
 N_{pl} = amount of production after asset comes on line, 10⁶ bbl [10⁶ m³]
 ΔN_p = volume, 10⁶ bbl [10⁶ m³]
 ΔN_{pif} = first year of incremental production
 ΔN_{pil} = last year of incremental production
 ΔN_{pINC} = incremental volume, 10⁶ bbl [10⁶ m³]
 ΔN_{ply} = volume in last sampled year greater than 1, 10⁶ bbl [10⁶ m³]
 ΔN_{pp} = peak production volume for base case, 10⁶ bbl [10⁶ m³]
 ΔN_{pP} = primary volume, 10⁶ bbl [10⁶ m³]
 ΔN_{pPV} = discounted volume, 10⁶ bbl [10⁶ m³]
 ΔN_{psv} = peak production volume for sampled vector, 10⁶ bbl [10⁶ m³]
 P = price, dollars/bbl [dollars/m³]
 P_{ca} = equivalent amortized price, dollars/bbl [dollars/m³]
 P_p = pipeline profit, dollars/bbl [dollars/m³]
 q_{EL} = production at the economic limit, bbl/well/D [m³/well/d]
 q_{ELB} = base for F_{EL} exponent
 q_p = peak production volume for sampled vector, 10⁶ bbl [10⁶ m³]
 s_i = size of increment, 10⁶ bbl [10⁶ m³]
 t = year
 t_a = final year of production
 t_o = year of operation

Superscripts

- a = decline
- X = fixed enhanced capital cost
- Y = fixed enhanced operating cost
- Z = variable enhanced recovery cost

Appendix—Relationship of Volume and TAPS Tariff

If the desired price locus is upstream of the wellhead—i.e., a market price is used— E_{ic} and E'_{ic} can include other transportation costs.

Although we use a Pump Station 1 wellhead price (market price minus shipping costs and TAPS tariff), the structure of the TAPS settlement methodology, the agreement that defined the derivation of the tariff, makes the tariff, and subsequently the wellhead price, sensitive to volume. Thus it is necessary to calculate the TAPS tariff.

Also, as the profit on TAPS (difference of tariff and variable operating costs) is considerable and influential on feasibility, we calculate the TAPS profit along with the tariff. (We do not, however, consider shipping or refining profit.)

Because volume and tariff affect each other, the derivation of tariff is done iteratively.

Initially, the sampled prices and volumes from all fields are brought in and a preliminary TAPS tariff is calculated. Because the tariff algorithm includes operating cost, TAPS profit, P_p , is also calculated. (Price is increased by profit in the ensuing revenue calculations.)

The model then examines the feasibility of Prudhoe Bay. If economic rent is negative, it is assumed that all other fields are infeasible as well. If economic rent is positive, EOR is examined. As an increment of EOR is added, volume increases and tariff decreases. Decreases in the tariff are reflected as increases in price, ΔE_{TV} , and P_p . Marginal revenue and cost are compared and the model continues to increment similarly until optimal production volume is computed.

Once the preliminary optimal production volume for Prudhoe Bay and tariff are established, the model examines Kuparuk in a similar fashion. If economic rent is negative, the model passes to the next field, eliminating the Kuparuk volume and recalculating the tariff accordingly. If economic rent is positive, EOR is examined and tariff changes as volume changes.

After the optimal volume for Kuparuk and tariff are established, the model passes to the next field and subsequently to all other fields in a similar fashion.

When the last field is exited, the TAPS tariff becomes fixed. The model then makes a second pass through all the fields with the new fixed tariff and recalculates the optimal production volume.

SI Metric Conversion Factor

$$\text{bbl} \times 1.589\ 873 \quad \text{E-01} = \text{m}^3$$

JPT

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MEMORANDUM

State of Alaska

Office of the Governor
Division of Policy

TO: Mary Halloran
Director

DATE: August 5, 1987
(minor emendations 8/12/87)

FROM: Gregg Erickson *GKE*
Senior Economist

PHONE: 465-3568

SUBJECT: Potential Severance Tax Loophole

Summary

Studies currently in progress by DOR economists in Anchorage, and other evidence, suggest that oil producers at Prudhoe Bay may be able reduce state severance taxes through a tax avoidance mechanism involving the newly applicable economic limit factor (ELF). The loophole was largely unanticipated, and has not yet been accounted for in the state's petroleum revenue forecasting models. The likely revenue loss is still uncertain. Efforts are underway to appropriately model company behavior and the potential tax avoidance mechanism in time for the December forecast.

Background

The ELF was first added to Alaska's severance tax in 1978 as part of an effort not just to increase revenue, but to do so in a way that would reduce the incentives in earlier severance taxes toward underdevelopment of the oil resource.¹ It was understood that the ELF could conceivably produce an opposite incentive -- toward overdevelopment.

¹Underdevelopment (sometimes called premature shutdown) occurs whenever a flat percentage tax is imposed on gross revenue. As the resource nears exhaustion the percentage tax takes an ever larger share of the potential profits; eventually it takes everything. At this point -- unless the tax is reduced -- production, profits, and tax revenues all end. This is a premature shutdown since all three would continue if taxes were reduced. Alaska adopted a sliding scale severance tax based on average per-well production in 1970. The ELF adopted in 1978 eliminated the "lumps" in that sliding scale and thus was expected to further reduce the under-development incentive.

This would be just as bad, since overdevelopment would also reduce state revenues.² Most analysts thought the overdevelopment risk was mainly a theoretical matter, however, with little potential for practical impacts on drilling, production rates, or major field investments. Even if there were some incentive for overdrilling, it was thought that the regulatory oversight of the Alaska Oil and Gas Conservation Commission would serve to keep it in check.

In past weeks evidence has accumulated suggesting that renewed application of the ELF to Prudhoe Bay, which occurred in June, may trigger a drilling program designed to artificially reduce severance tax rates. Under such a program, additional wells could cost more than the gains from increased oil production as long as the difference is more than offset by the transfer to the companies of severance tax revenue -- revenue that would have gone to the state had the well not been drilled.

From the state's standpoint, overdrilling would cause a fall in state severance tax revenue from a source not thus far anticipated in the state's forecast models. A collateral effect would be a shift in the production curve, moving future production toward the present but steepening the rate of decline later. Output over the life of the field would likely increase. Nevertheless, total economic rents -- the difference between production costs and the value of the oil -- would be reduced.

²Many people have a hard time understanding how overdevelopment can be a bad thing. They forget that it is profits and net tax revenues that make oil production so desired, not more barrels, *per se*. As an extreme example, assume some edict required all profits and tax revenues from a field reinvested to drill additional wells in the field. Both the state and company would find this a bad deal, despite the resulting increase in production. Neither would receive any net benefits from the resource, all of it having been dissipated on the excess investment. Oil drillers and drilling companies would naturally like the idea, but society as a whole would be worse off.

The New Evidence

The first piece of evidence in this regard surfaced in late March in testimony of ARCO Kuparuk Unit Manager James Weeks before the House Finance Committee. Mr. Weeks provided an example showing that under the present ELF it is possible for total production to increase at the same time total severance tax collections decrease. This is exactly the condition that is necessary for overdevelopment. Weeks argued that this was a desirable characteristic of the tax structure.³

The second piece of evidence was the result of ongoing Department of Revenue (DOR) modeling work. Over the past year DOR economists in Anchorage had been preparing fiscal notes on various concepts for revising the ELF. In the course of that work and even before, as a part of their regular forecasting, the DOR economists had modeled the impact of different tax structures and oil prices on the decision to produce Alaska North Slope oil fields. An early version of that model, now called the "production module," was integrated into the large PETREV forecasting model in September 1985.

The production module assumes that prices and tax structures will have no effect on the optimum number of wells or other field investment, only on the decision to produce or not. Initially this assumption seemed like a reasonable simplification; but as the DOR economists got more involved in preparing ELF fiscal notes they became concerned that there might be important field investment effects that the module was not designed to detect.

The ARCO testimony in March added additional urgency to these concerns, since it showed that at least one oil company

³ARCO's example and OMB's April 29 critique of the ARCO argument is found in Attachment A.

was talking publicly about drilling wells that were only economic for it because of a potential tax rebate inherent in the ELF structure. Last Friday Dr. Roger Marks at DOR provided us with preliminary results from a new production model, one which shows the effect of changing prices or taxes on drilling.⁴ The results suggest that the ELF does indeed create an incentive at Prudhoe for operators to reduce their taxes through overdrilling.

The third piece of evidence is found in July *Anchorage Times* reports of plans by ARCO and Standard Oil Company to increase drilling at Prudhoe Bay. The stories (see Attachment C) speak for themselves. Neither ARCO nor Standard announced any such plans; according to an ARCO official, the plans were revealed to the *Times* only after their reporter directed inquires to field personnel regarding trade press notices showing that ARCO was seeking bids for additional drilling services.

Further Action

No immediate action is recommended. I have encouraged Dr. Marks to continue his analysis, and he indicated his intention to do so. He hopes that a new model taking account of drilling incentives can be integrated with the production module and large forecasting model in time for the December forecast, but it is conceivable that it could take longer. I have also asked DOR to model the incentive structure in the ELF formula that passed the House in 1987 (CSHB 164 (fin.) am.). I would hope that the proposed formula would eliminate much of the problem. We will see. In any event, Dr. Marks and his colleagues should be congratulated for calling this potential problem to our attention.

⁴A draft of Marks' paper is found in Attachment B.

Mary Halloran
August 5, 1987
Page 5

- Attachments: A. "Technical Note on ARCO's Kuparuk Example,"
OMB, 29 April 1987.
- B. "A Model To Evaluate the Economics of
Drilling Additional Wells," Roger Marks, DOR,
August 1987.
- C. *Anchorage Times*, "Arco to increase oil
production," 15 July 1987, and "Standard adds
drill rig to Prudhoe field," 16 July 1987.

cc: R. Marks, DOR
J. Rhode, DOR
R. Fineberg, OMB/Policy

TECHNICAL NOTE Attachment A

ON ARCO'S KUPARUK EXAMPLE

Tax Effects of Drilling an Additional Well Under Current Law

Mr. James Weeks, Kuparuk Unit Manger for ARCO, provided testimony to the House Finance Committee on March 27, 1987. Examples of severance tax effects (see following page) accompanied his testimony. The examples compare the severance tax effects of adding one additional well in the Kuparuk field under the current ELF and under the proposed ELF (CSHB 154 fin.). The examples show that the addition of one well producing just under 300 barrels per day would increase output from 90,168,000 barrels of oil per year (BOPY) to 90,277,000 BOPY. At the \$9.00 per barrel price assumed in ARCO's example, annual gross revenue to the owners increases by \$981,000.

$$(90,277,000 \text{ BOPY} - 90,168,000 \text{ BOPY}) * (\$9/\text{barrel}) =$$

$$(109,000 \text{ BOPY}) * (\$9/\text{barrel}) = \$981,000$$

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

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

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

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

**DRILLING/WORKOVER DISINCENTIVE
COMMITTEE SUBSTITUTE HB 164**

SEVERANCE TAX CALCULATION

CURRENT LAW

Field Rate × Wellhead Price × Severance Tax × ELP

90,168,000 BOPY × \$9/BO × 0.15 × 0.52134

= \$63,461,050/year

Addition of 1 well :

90,277,000 BOPY × \$9/BO × 0.15 × 0.5204

= \$63,423,203/year

A decrease of \$37,846 year

PROPOSED LAW

Field Rate × Wellhead Price × Severance Tax × ELP

90,168,000 BOPY × \$9/BO × 0.15 × 0.7296

= \$88,811,873/year

Addition of 1 well :

90,277,000 BOPY × \$9/BO × 0.15 × 0.7292

= \$88,870,484/year

An increase of \$58,611 year

[ARCO Handout, March 27, 1987]

Attachment B

A Model to Evaluate the Economics of Drilling Additional Wells

Roger Marks
State of Alaska Department of Revenue
Petroleum Research Section
August 1987

The oil production severance tax structure in Alaska causes the tax to be sensitive to the number of wells in a field. Levied on non-royalty barrels, the tax is the product of the wellhead price (market price less shipping and pipeline costs), the severance tax rate, and the economic limit factor (ELF). The ELF is a number between zero and one which reduces the severance tax as well productivity declines and a field approaches its economic breakeven point:

$$ELF = \left(1 - \frac{PEL}{TP} \right)^{\left[\frac{460 * WD}{PEL} \right]}$$

where PEL = the monthly production rate at the economic limit
TP = total production during the month for which the tax is to be paid
WD = the total number of well days in the month for which the tax is to be paid

Thus, for example, with all other things equal, as wells increase, PEL will increase, PEL/TP will increase, the base of the exponent will decrease, and the ELF, along with severance tax, will decrease.

Recently there have been legislative proposals to modify the severance tax structure, notably the form of the ELF. Meaningful judgments on the merits of the proposals will depend, among other things, on how they affect development, productivity, profitability, and State revenues.

The State of Alaska Department of Revenue's current forecasting model has a component that computes the economic rent of specific fields to assess whether or not they are feasible to produce given price and volume scenarios. When economic rent is negative production is delayed until a start-up year generating positive economic rent is found. This reduces the likelihood that the model will project revenue from uneconomic fields. When economic rent is positive the model finds the profit maximizing amount of enhanced recovery.

Projected price, volume, and well numbers are exogenous input, with the latter two based on producer public information and State engineering assessments. They reflect the current and announced extent of development, a rather limited time horizon.

Consequently, the Department has developed a model to examine the economics of drilling additional wells in developed fields. Such a model indicates the degree of extra in-fill drilling and production that may occur to maximize economic rent for primary recovery, and is also useful for analyzing potential severance tax structures.

The crux of the model is the relationship it establishes between additional wells and the production profile. On that matter the model is generic while reservoirs are unique, but reflects general engineering principles. The model does allow reasonable systematic comparative policy analysis in an area where the answer is unknowable.

The production decline characteristics of many oil wells and fields follow exponential declines. The slope of the decline curve is called the exponential decline rate, a , where:

$$a = \frac{\ln\left(\frac{q_i}{q_f}\right)}{t}$$

q_i = production rate at the beginning of any time period during the decline

q_f = production rate at the end of the time period

t = number of years between q_i and q_f

Production in any year is $1/e^a$ times production in the previous year, where e , the number whose natural logarithm is one, is approximately 2.71828. We henceforth refer to $1/e^a$ as the production multiplier, P . Similarly, the well count will decline as producers are converted to injectors as production, saturation, and pressure drops. The well decline multiplier is estimated at $.5*(1+P)$.

In general, the major impetus for in-fill drilling is to produce a finite amount of oil sooner. Given an initial decline rate, a_B , additional wells will slow down the decline rate on a field basis to a_M , and the initial production multiplier P_B ($1/e^{a_B}$) increases to P_M as a_B decreases. a_B will decrease at a decreasing rate as wells are added. At Prudhoe Bay a_B is estimated to be 0.090, and P_B is 0.91394.

As wells increase the production multiplier will increase such that

$$P_M = P_B + f(w),$$

where w is the number of additional wells, and production for a given year, V_t , will be

$$V_{t-1} * P_M$$

where V_{t-1} is production in the previous year.

$f(w)$ is approximated by the form

$$C * \left[\ln \left(\frac{\left(w + T^{\frac{x-1}{x}} \right)^x}{T^{x-1}} \right) \right]$$

where T = total wells prior to decline. For Prudhoe Bay T is estimated at 541.

$x = 3$ is determined such that

$$\left[\ln \left(\frac{(.25 T + T^{\frac{x-1}{x}})^x}{T^{x-1}} \right) / \ln \left(\frac{(T + T^{\frac{x-1}{x}})^x}{T^{x-1}} \right) \right]$$

This calibrates $f(w)$ such that 50 percent of the change in $f(w)$ that would result from doubling w is realized after w is increased 25 percent.

$$c = \left(\frac{1}{e^{a_8 - .002}} - \frac{1}{e^{a_8}} \right) / \ln \left(\frac{(w + T^{\frac{x-1}{x}})^x}{T^{x-1}} \right)$$

This coefficient calibrates $f(w)$ such that as $w = T$ (i.e. the number of wells is doubled), a_8 is reduced by two one-thousandths. For Prudhoe Bay c is estimated to be 0.0002755271.

The intercept term $(T^{\frac{x-1}{x}})$ calibrates $f(w)$ so $f(w) = 0$ when $w = 0$.

There is a limited amount of reserves remaining before exponential decline decays into arithmetic. For Prudhoe Bay this is estimated to be 4 billion additional barrels after 1987. The model stops exponential decline when accumulated post-1987 production reaches this estimated limit, and begins arithmetic decline, decreasing production each year by a constant amount equal to the difference in production between the prior two years. Note that arithmetic decline will begin sooner where more wells have been drilled. Also, this gives a more rapid decline where more wells had been drilled, accelerating the arrival of economic shutdown, and consequently total recovery over the economic life of the field may be less with greater numbers of wells even though economic rent is greater.

The model is incorporated into a conventional discounted cash flow profitability model specific to the North Slope. A number of additional wells (w) is exogenously inputted (along with their costs), and a third of them are added in each of the three years 1989 through 1991. A ceiling of T is put on w . Volume is adjusted as specified above. The model cuts off production when after tax net value is negative. The number of additional wells that maximizes economic rent is found iteratively.

Our estimates of the optimum number of additional wells for Prudhoe Bay under current law, as a function of constant real Pump Station One (PS1) price, are as follows. (These prices are approximately \$5 under market prices.)

<u>Price</u>	<u>Additional Wells</u>
\$15	3
\$20	100
\$25	316

Table 1 compares the well count, production volume, and economic rent, with and without an optimized in-fill drilling program, at a \$20 PSI price.

Table 2 compares the well count, production volume, and economic rent between optimized in-fill drilling programs at \$20 and \$25 at PSI.

Table 1
 Comparison of Wells, Volume, and Economic Rent
 With and Without an Optimized In-fill Drilling Program
 \$20 PSI Price

	<u>No Optimization</u>		<u>Optimization</u> (100 wells)		<u>Increased Wells</u>	<u>Increased Volume</u> (mmbbl)
	<u>Wells</u>	<u>Volume</u> (mmbbl)	<u>Wells</u>	<u>Volume</u> (mmbbl)		
1988	541	561	541	561	0	0
1989	518	513	551	513	33	0
1990	495	469	560	469	65	0
1991	474	428	569	429	95	1
1992	454	391	544	392	90	1
1993	434	358	521	359	87	1
1994	416	327	499	328	83	1
1995	398	299	477	300	75	1
1996	381	273	457	275	76	2
1997	364	250	437	251	73	1
1998	348	228	418	230	70	2
1999	333	207	400	208	67	1
2000	319	185	383	187	64	2
2001	305	164	366	165	61	1
2002	292	142	351	144	59	2
2003	280	121	336	122	56	1
2004	268	99	321	101	53	2
2005	256	78	307	79	51	1
2006	245	56	294	58	49	2
2007	235	35	281	36	46	1
2008	224	13	269	15	45	2
Total		5196		5223		27
Economic Rent (\$mm)		29467		29501		34

Table 2
Comparison of Optimized In-fill Drilling Programs
\$20 and \$25 PSI Prices

	<u>\$20</u>		<u>\$25</u>		<u>Increased</u> <u>Wells</u>	<u>Increased</u> <u>Volume</u> (mmbbl)
	(100 wells) <u>Wells</u>	<u>Volume</u> (mmbbl)	(316 wells) <u>Wells</u>	<u>Volume</u> (mmbbl)		
1988	541	561	541	561	0	0
1989	551	513	622	513	71	0
1990	560	469	700	470	140	1
1991	569	429	774	430	205	1
1992	544	392	740	393	196	1
1993	521	359	709	360	188	1
1994	499	328	678	330	179	2
1995	477	300	649	302	172	2
1996	457	275	621	276	164	1
1997	437	251	594	253	157	2
1998	418	230	569	231	151	1
1999	400	210	544	212	144	2
2000	383	192	521	194	138	2
2001	366	176	498	177	132	1
2002	351	161	477	162	126	1
2003	336	147	456	148	120	1
2004	321	134	437	136	116	2
2005	307	123	418	124	111	1
2006	294	112	400	114	106	2
2007	281	103	383	104	102	1
2008	269	94	366	95	97	1
Total		5223		5251		28
Economic Rent (\$mm)		29501		38275		8774

Attachment C

QUALITY SERVICES

Date JUL 15 1987

Anchorage Times

Client No. 30

Arco to increase oil production

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By Ray Tyson
Times Business Writer

Arco Alaska, Inc. plans to sink five more production wells at Prudhoe Bay beginning in September in the first major increase in drilling activity at Prudhoe in 14 months.

Arco's decision to add an additional oil drilling rig is directly related to recent increases in the price of crude oil, said Arco drilling manager Randy Ruedrich.

It means an additional 100 field jobs at Prudhoe and several hundred more jobs in related businesses in Anchorage and Fairbanks, Ruedrich said.

If the oil price climate continues to improve, he said, further drilling can be expected in the near future.

"This is very good news," Ruedrich said. "It's the first sign that higher crude prices are affecting Alaska's economy."

Hugh Depland, spokesman for Standard Alaska Production Co., which along with Arco operates the Prudhoe Bay field, said Arco's decision to increase drilling required the consent of the eight owners, especially Standard, which owns 50 percent of the field.

Depland said any plans to increase production at Prudhoe required approval of at least 90 percent of the owners.

Arco and Exxon Company USA, the other major owners, each own about 21 percent of the field.

Since oil prices collapsed last year, Arco has reduced the number of rigs on the Slope from 10 to 2, eliminating about 800 field jobs and countless thousands of related jobs in the Railbelt.

"When world crude prices came unglued we began to stack (eliminate) rigs," Ruedrich said. "Now we're in a position to begin replacing" those whose contracts have expired. "This means we don't have to stack another rig."

The contractor to provide and operate the new rig to drill \$13 million worth of production wells at Prudhoe will be announced in early August. Drilling will begin about Sept. 1.

Arco also plans to replace a production oil rig at the nearby Lisburne field, which it had planned to eliminate, and continue current production activity at the Kuparuk River field west of Prudhoe.

QUALITY SERVICES

Date JUL 16 1987

Anchorage Times

Client No. 350

Standard adds drill rig to Prudhoe field

Anticipates another dozen before end of year

345A 350 0360 0590

Standard Alaska Production Co. has added a drilling rig to its Prudhoe Bay operation, signaling yet another industry response to increasing oil prices following months of relative inactivity.

Arco Alaska, Inc., which along with Standard operates the field on behalf of eight owners, announced on Tuesday plans to add an additional rig to drill five production

wells beginning in September.

Standard spokesman Hugh Depland said today the new Standard rig began operating in mid-June.

Standard, which plans to sink about 12 more production wells by the end of the year, now has two rigs operating on the western portion of the field.

The new Arco and Standard rigs mean an extra 200 field jobs and

several hundred more jobs in related industries in Anchorage and Fairbanks.

It costs about \$2.3 million to drill a production well.

Wells must be added to maintain the 1.5-million-barrel-a-day production level at Prudhoe Bay.

"The signing on of an additional rig was made possible by the improvement in oil prices," Depland

said. "We had planned to do this all along. But the increase in prices made it possible."

Oil prices have steadily increased since they hit rock bottom at \$8 a barrel last year.

Oil futures today reportedly climbed to \$22 a barrel, the highest in 18 months.

Oil prices at West Texas Intermediate, the U.S. benchmark, jumped to \$22.15 a barrel.

U.S. Dependence on Oil Imports Is Shooting Up But Congress, White House Fumble With Policy

By ROBERT E. TAYLOR

Staff Reporter of THE WALL STREET JOURNAL
WASHINGTON—Less than two years ago, 27% of the U.S. oil supply was imported. Today the foreign share is about 40%, but although there's cause for concern, Congress and the Reagan administration can't seem to get together to reverse the trend.

"You have to ask why they don't do something," says Charles DiBona, president of the American Petroleum Institute, the domestic oil industry's leading trade group. Although Mr. DiBona has a direct interest in seeing imports' share of the U.S. market diminish, his complaint is shared by many experts outside the industry.

"We aren't doing anything to make foreign oil less important," says Eli Bergman, executive director of Americans for Energy Independence, a private foundation.

Interior Secretary Donald Hodel predicts the return of gasoline lines in as little as two years. Failing to curb imports, he says, is like telling oil-producing countries, "Take advantage of us, we're not going to defend ourselves." The Fund for Renewable Energy and the Environment, a coalition of environmental groups and supporters of alternative energy sources, who seldom agree with Mr. Hodel, warns that the U.S. is failing to prepare for "inevitable" oil price increases that "could well imperil the national economy and the country's security."

Which Way Do We Go?

The difficulty is reaching agreement on what to do. The oil industry and some others want to encourage increased U.S. production by means of an oil-import fee or with tax incentives. But a price-raising import fee or tax breaks for the oil industry raise steep political hurdles in the form of strong opposition from oil-consuming interests. Meanwhile, environmentalists' proposals to stimulate conservation and increase use of substitute fuels are blocked by the administration.

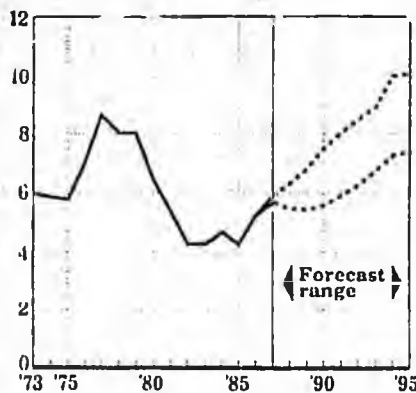
Currently stirring controversy is a proposal by Senate Finance Chairman Lloyd Bentsen (D., Texas). He recently got his committee to amend the pending trade bill to require the president to do whatever is necessary to keep oil imports from exceeding 50% of the U.S. supply, subject to congressional veto. But New Englanders and Midwesterners oppose the amendment as a backdoor route to an import fee that would raise fuel costs. "It's simply unfair," says Sen. John Chafee, (R., R.I.), whose constituents get two-thirds of their energy from oil.

The problem will worsen, forecasters say. Oil imports are expected to top 50% of the U.S. supply between 1990 and 1995. That would heighten the importance of the volatile Persian Gulf. Although the U.S. now gets only about 6% of its oil from the gulf, that region is expected to dominate world oil markets in the 1990s when the current world oil glut is expected to be over.

Congress has made small energy-conservation moves. It passed a bill, reluc-

U.S. Net Oil Imports

Actual and forecast, in millions of barrels per day.



Source: Energy Information Administration through 1986 and Energy Department forecasts thereafter.

tantly signed by President Reagan, reinstating appliance-efficiency standards. The House currently is exploring ways of diverting 2% of all oil imports into the nation's Strategic Petroleum Reserve, and there has been talk of a gasoline tax that would be used to help cut the budget deficit while discouraging consumption.

Although administration officials say the president has supported "appropriate" responses to the oil-import problem, such as lifting the oil-industry's "windfall" profits tax and opening more federal lands to drilling, industry leaders are skeptical that much will be done. David Wilson, president of the Independent Petroleum Association of Mountain States, says that both Congress and the administration "are hoping the situation will go away without action on their part."

Just last month, Mr. Reagan killed a seven-month drive by some administration officials to get him to take strong new action. The Energy Department urged the president to propose tax credits and quick expensing of oil-exploration costs totaling \$560 million to \$960 million annually. It projected these would boost domestic production after five years by 500,000 barrels a day, or about 6%.

According to Mr. Hodel, some cabinet members were loath to open last year's tax law to assaults by special interests. Top officials also balked, insiders say, at the cost of tax breaks and the difficulty of pushing them through Congress.

Oil Reserve Plan Scrapped

Also scrapped was an Energy Department plan to buy more oil for the strategic reserve. It urged that private investors be allowed to own the oil through government-backed securities. Instead, Mr. Reagan said he would support tripling his proposed purchase rate for the reserve to 100,000 barrels a day *only* if Congress found a way to pay for it.

"That makes no sense," says oil-state lawmaker Bennett Johnston (D., La.), chairman of the Senate Energy Committee. Even the administration says such reserves are crucial to enable the U.S. to comfortably ride out small oil-supply dis-

ruptions like those of the 1970s.

Talk of gasoline taxes and alternative oil leasing systems was blocked by Reaganite aversion to taxes and regulation. Import fees were doomed by the administration's projection that they would be extremely costly without producing much more oil.

Harvard professor William Hogan argues that the benefits of a \$10-a-barrel fee actually would exceed its costs. But the Energy Department doesn't buy Mr. Hogan's view. Neither does Robert Fri, president of Resources for the Future and a former head of the Energy Research and Development Administration, who says, "Energy is a long term problem, and quick fixes will do more harm than good."

But even Mr. Fri says that "the administration should have a more comprehensive program," mainly in research and development on cheaper oil production and ways to use substitute fuels, such as methanol, to fuel automobiles.

Curbing oil imports hasn't been a priority, complains the oil industry's Mr. DiBona. "In this country, we tend to deal with the immediate crisis, not the long-term problem," he says, faulting administration officials for inattention to energy amid the distractions of Iran-Contra hearings and other issues.

Rep. John Dingell (D., Mich.) charges that Mr. Reagan has a "do-nothing approach" to preparing for "the next energy crisis." Others contrast the inaction on oil imports with Mr. Reagan's quickness to defend Persian Gulf shipping. Irwin Steltzer, the director of the Energy and Environment Center at Harvard University's Kennedy School of Government, says, "I think our (energy) policy is called aircraft carriers."

Opinion

Should Alaska change the ELF formula?

Editorial Opinion and Comment of

FAIRBANKS

Daily News - Miner

Independent in All Things Neutral in None

Other opinions expressed on this page do not necessarily reflect those of the Daily News-Miner.

Treating the symptom?

Judging from the recent audit, critics of the city's steam heat utility were right all along.

The audit showed that a shocking two-thirds of steam-heated properties had meter bypasses.

Six of the bypasses were found to be active during the well-publicized March audit, meaning the customers got steam without it showing up on their meters or their utility bills. There's no way of telling how many were active when the city wasn't looking.

All of which may do much to explain why the system "loses" about a third of its steam, has lost more than \$3 million since 1980, and expects to lose another \$550,000 this year.

The critics, consisting mainly of steam-heat users who have been paying their bills, had complained that recent rate increases wouldn't have been necessary if the system was run efficiently, and it's clear now they were on target.

An ordinance before the city council should bring the bypass problem under control and stop losses to unmetered users, and the downtown utility work should cut losses from leaks in the steam lines.

Let's hope these improvements end the need for more rate increases, as well as the system's financial hemorrhage.

But let's not forget that MUS management allowed the problem to fester for years, and did the audit chiefly in response to pressure from customers and elected and appointed officials, rather than from any internal drive for efficiency or fairness.

Consequently, it's not safe to assume an ordinance will permanently fix the system's problems. As long as the same managers are in charge of it, the cure may be only temporary.

The merry month

In May, many things are honored of which we

By SAM COTTEN
The importance of oil and gas development in Alaska's economy can't be overstated. As Alaskans we derive the largest part of our economic development and public revenue from our oil fields and oil taxes. But judging from the fact that Prudhoe Bay producers are due to receive an \$80 million tax break from the state this June, there is something wrong with our existing tax structure.

Prudhoe Bay is by far the most productive and profitable field in United States history. Prudhoe oil producers have made huge profits from developing this resource, owned by the people of Alaska, and from shipping and refining the oil produced there.

It is unrealistic to say, as some industry advocates have, that maintaining the current tax regime for this field (by passing the House bill), will destroy or diminish Alaska's oil industry. Prudhoe Bay and

By HAROLD HEINZE
It is vital that Alaskans think about how they fit into their local and state economy so they can encourage activities that contribute to jobs and income.

In Fairbanks, the economy is directly impacted by the level of North Slope drilling activity. When oil prices fell, drilling diminished. Now, new oil severance tax legislation passed by the state House would discourage an increase in drilling activity. That's bad news for Fairbanks.

Statewide, the fuel supply for the state's economic engine is the dollars derived from extracting and exporting natural resources, including oil and gas, fish, timber, minerals and coal.

The gross value of oil and gas produced in Alaska in 1986 was \$4 billion. That's the money derived from selling those resources on the world market. In 1983, when oil prices were considerably higher, the comparable number was \$12 billion. If you have wondered why the Alaskan economy is sputtering, it is entirely contained within that one single change. Nonfuel natural

Yes

Guest Opinion

Kuparuk—the two fields that receive smaller tax breaks under the Economic Limit Factor (or ELF) bill that recently passed the House—are healthy, profitable fields.

This bill makes our oil tax system more equitable and sensible. It does two important things:

1. It prevents large tax breaks for giant oil fields like Prudhoe Bay and Kuparuk, where tax incentives aren't needed. These large tax breaks are scheduled to take effect at the end of June, and they will mean the loss of about \$90 million to \$120 million in revenue per year over the next five years.

2. It provides tax incentives for production from every other known field in Alaska. These are smaller, more marginal fields like Endicott, Lisburne, and Milne Point—which was recently shut down because its production was uneconomic.

This makes sense. Where marginal fields can be developed in Alaska, they provide jobs and in many cases substantial royalty income to the state. They broaden the industry and brighten the future for production from other marginal fields.

Some industry representatives are saying now that the state shouldn't change its tax system, that "tax stability" is the most important issue here. The proposed changes to the ELF will not cause Prudhoe and Kuparuk producers to stop or limit production, which has been growing rapidly. And it will enhance the economic viability of smaller fields.

So the real issue for these indus-

try representatives, of course, is money. It's clear from history that the industry actually favors an "unstable" tax regime when it will benefit.

For instance, when the price of oil was climbing in 1981, the oil industry came to the Legislature and asked for tax breaks. The Legislature responded, implementing a new "unitary" tax system for Alaska. Since that time, the people of the state of Alaska have foregone more than a billion dollars worth of revenue that would have been collected under the former system.

I am not reopening the question of the unitary tax vs. separate accounting of taxes. But I am pointing out that the industry has been the willing beneficiary of select "unstable" tax policies in the past.

In this case, if the Legislature does not change the current tax system, the state of Alaska will forfeit needed revenue that could have been used in our shrinking school

budgets, for maintaining roads, and for continuing resource management programs that the Senate now advocates cutting by 15-25 percent. And smaller, marginal fields in Alaska will continue to be inequitably treated under existing law.

The facts about the ELF and the proposed ELF changes show that we need a different tax system. The vague representations by oil industry representatives—that the industry will be deeply damaged, that Alaska will lose points for being a profitable state—have not been convincing.

I am strongly supportive of Gov. Cowper's effort to modify the existing ELF law. The House and Gov. Cowper are working together for a tax system that truly serves the interests of Alaskans.

Rep. Sam Cotten, D Eagle River, co-chairs the Alaska House Resources Committee.

No

Guest Opinion

resource value changed significantly.

Two other sources of fuel for the Alaska economy are tourism and defense spending by the federal government. State government is not on the list because it does not create wealth; it runs off the same fuel supply as the private economy. (The only exception is the state's Permanent Fund dividend program.)

What does it take to succeed in the natural resource business? Since they all are sold in the world market at world prices, the key to success is to be a low cost producer. The resource industries all are alternative to government regulation and they all require access to the land.

There's been a lot of conversation about diversification of the state's economy. But the best answer I know to what fills the economy is to

figure out ways to help the natural resource industries grow. They are already big contributors to the state's economy and increases in any of them help the economy grow.

When we look at the \$450 million ARCO Alaska has spent in Fairbanks over the last four years, we find, as expected, that the construction companies based in Fairbanks are a big part of that.

However, the construction dollars represent only about a quarter of the money ARCO is putting into the Fairbanks economy. Drilling activities and trucking are major pieces of that dollar infusion.

More than half the traffic on the Dalton Highway, for example, represents Fairbanks carriers hauling things for ARCO Alaska. In the early years of Prudhoe development, most supplies traveled to the North Slope by barge. But Fairbanks people worked together and made freight movement up the highway a very competitive thing.

The changes to the state's Economic Limit factor, which are in a bill recently adopted by the state House of Representatives, would have a major adverse impact on ARCO's

North Slope drilling activity. That means the entire Fairbanks economy will be negatively impacted.

What started as a proposal by the governor to modify one portion of the severance tax law ended as a major restructuring of the severance tax on the oil industry in Alaska. Producers would be penalized for drilling additional wells and adding new production.

The new bill (House Bill 164) would increase the severance tax on the Kuparuk River field by 64 percent, and on the Prudhoe Bay field by 44 percent. We calculate that it would add \$1.8 billion to industry's tax bill over the next 10 years, based on state Department of Revenue oil price estimates.

In restructuring the tax, the House introduced new factors. Instead of basing the tax on production from each well, it relates the tax rate to the production level from an entire field. That means the more oil produced from a field, the higher the tax rate. It removes any incentive to increase production.

In our business, you drill wells and try to increase production to lower operating costs. That's how

we compete and how we generate more jobs and more wealth for everyone. The House bill is counterproductive.

Passing that bill tells me that the House majority is not looking at the impact on the private sector.

I know that many people in Fairbanks are working to get the economy going. But when the vote was taken in the House on the severance tax, the five House representatives from Fairbanks all voted for the tax increase.

The state Senate is going to have to address this issue. Your input to Senate members from Fairbanks will be vital in deciding the issue.

Other oil producing states are looking for ways to encourage oil producers to drill more wells. Those states are aware of the benefits of oil development activity. Meanwhile, the Alaska House has passed new legislation that discourages drilling in the Prudhoe Bay and Kuparuk oil fields. It is new state policy that will further dampen drilling activity on the North Slope and further shrink the state's private economy.

Harold Heinze is president of ARCO Alaska, Inc.

ARCO Alaska, Inc.

Post Office Box 100360
Anchorage, Alaska 99510-0360
Telephone 907 265-1500



Mark L. Hazelwood
Vice President - Finance, Planning & Control

May 4, 1987

The Honorable Al Adams
Chairman, House Finance Committee
House of Representatives
P. O. Box V, Capitol, Room #509
Juneau, Alaska 99811

Dear Representative Adams:

In response to my testimony of March 19, 1987 to the Joint House Finance and House Resources Committees, several questions were directed to me regarding the effects of the proposed CSHB 164. The most important aspects of the proposed legislation are the detrimental effect it has on incremental development projects and the associated oil production. As I stated in my testimony, the continued development work at Prudhoe Bay relies on expensive, technologically enhanced recovery techniques and the drilling of extensive in fill wells. Although Prudhoe Bay as a whole is not a marginal field, the individual incremental development projects required to maximize ultimate oil recovery are very marginal.

In answer to one of the questions posed after my testimony, I noted that the barrels of oil which may be foregone due to the passage of this legislation would be far in excess of the 34 million barrels calculated for Prudhoe Bay by the Department of Revenue. Subsequent review has established our estimate of oil which may be left in the ground at Prudhoe Bay (due to the effects of this tax increase) at approximately 200 million barrels. This is equivalent to several times the total production currently projected over the life of the Milne Point field. A loss of this magnitude of oil production, the resultant loss in revenue to the state government, and the attendant loss of employment opportunities for Alaskans can hardly be in the state's best interest.

With regard to the questions concerning the Department of Revenue models which originally developed the reserve loss figures cited above, subsequent testimony by Dr. Logsdon of the Department of Revenue on March 27, 1987 indicated the variability inherent in those Monte Carlo simulation models. While our final analysis of the Department of Revenue's model is not yet completed, I have attached some preliminary comments based on our initial review of the assumptions and concepts employed in the model.

The Honorable Al Adams

May 4, 1987

-2-

Finally, a question was raised concerning the figure stated in my testimony on the state's share of total oil and gas net revenues during 1986. In response I would note that this figure was developed utilizing ARCO's internal financial data and is not meant to necessarily represent the total industry. For an analysis of the breakdown of the shares of net revenue across the entire industry, I would recommend to you the Department of Revenue's data compiled earlier this year for the Joint Legislative Special Committee on Tax Policy. This analysis was submitted to the House Finance Committee by Standard Alaska Production Company on March 27, 1987.

If you would like to discuss further any of the above comments, please let me know.

Sincerely,



Vice President
Finance, Planning & Control

Attachment

c: Members of the Senate
House Finance Committee
House Resources Committee

PRELIMINARY COMMENTS

ECONOMIC FEASIBILITY AND OPTIMUM PRODUCTION VOLUME MODEL

STATE OF ALASKA DEPARTMENT OF REVENUE

The model is formulated in constant (real) dollars and does not include the effects of inflation even within the model itself. A more proper methodology is to inflate the various cash flow streams and perform the various calculations then deflate the net after tax cash flow by the same rate. Failing to account for the impact of inflation causes serious problems since federal and state income tax effects are not properly reflected.

The model includes profits from the Trans Alaska Pipeline in the decisions on individual field economics. This is a concept we have in the past pointed out as invalid; however, even if it were valid, the model's assumption that those profits should be added to individual field revenue is false. It assumes that each pipeline owner receiving the profits would have that money available to offset the impact of unprofitable operation at the field wellhead, and such is not the case.

The model makes projected production volume sensitive to the projected price. This assumption is refuted simply by looking at

1986 production volumes which were not reduced despite the extremely low oil prices evidenced at that time. This assumption would make production over the field life appear more profitable than it would be in actuality.

The model does not consider the reality of phased North Slope oil field development. Although major facility projects are normally completed over a several year period, development in the form of drillsites and individual wells continues over decades.

The model assumes secondary or tertiary development begins five years after initial production. Actual experience at the Kuparuk field proves that expensive secondary recovery techniques can become necessary almost immediately upon start-up, depending on the particular field's reservoir characteristics.

The model assumes that if marginal revenue exceeds marginal cost, the production volumes associated with enhanced recovery can be increased up to some empirically estimated factor. This ignores the pertinent and often overriding technical factors involved in the secondary and tertiary development projects.

The model appears to incorrectly calculate federal tax depreciation with regard to intangible drilling costs.

The model assumes that a producer would automatically take advantage of the opportunity to rebut the 300 barrel per day per well presumption. This assumption is misleading in that the administrative and legal expense of mounting a challenge to the PEL is not considered; and a producer may not go to the effort of mounting a rebuttal based on his perception of future oil prices.

The model appears to assume a constant transportation and quality differential between a field wellhead value and the TAPS Pump Station #1 price.

The model assumes an unlimited amount of capital available to producers within the specified discount rate.

Sam:

Here is an analysis of the attached articles, which relate to Texaco, ARCO, and Standard profits for the first quarter of this year. Obviously these are very preliminary and superficial comments. The concept bears some more looking at.

You will note that Standard gets 97% of its oil from Alaska. If there is a baseline regarding the profitability of Prudhoe/Alaska production, this is it.

Standard made \$200 million on \$2.5 billion in sales last quarter. This works out to \$1 in profit for every \$12.50 in sales.

ARCO, which derives a large amount of its oil from Alaska (but less than Standard), made \$238 million on \$3.75 billion in sales last quarter. This amounts to \$1 in profit for about every \$16 in sales.

On the other hand, Texaco (a more diversified producer/refiner/marketer with a relatively small share of Prudhoe), made \$118 million on \$8.5 billion in sales. This is \$1 in profit for every \$70 or so in sales. (The Chapter 11 stuff can't have had too big an impact on Texaco. First of all, their assets are protected under Ch. 11. Second, last year they only made \$328 million on \$9.6 billion in sales -- still only \$1 in profit for \$30 in sales.)

Also note that Standard, by juggling the figures in its vertically integrated operations, is able to derive suddenly higher profits (14 times higher than last year) from marketing and refining. ARCO is similar, and brags about the ability to do well in a low-price environment. These guys are killing us!

It would be fun to compare annual/quarterly reports for North Slope/other producers, talk to the PR guys at the different companies, and figure out how massive the Alaska-derived profits really are at Standard and ARCO.

red

Three Oil Firms Report Lower Quarterly Profit

Standard's Decline Was 21%;
 Net Fell 98% at Ashland,
 20% at Atlantic Richfield

A WALL STREET JOURNAL News Roundup
 Three U.S. oil companies posted earnings declines for the latest quarter, reflecting lower profit margins.

Earnings fell 21% at Standard Oil Co., 20% at Atlantic Richfield Co. and a whopping 98% at Ashland Oil Inc.

At Ashland and Arco, product prices failed to keep pace with rising crude oil prices while at Standard, the drop reflected lower Alaskan crude oil prices compared with a year ago.

Standard Oil Co.

Cleveland-based Standard posted a 14% decline in first-quarter revenue to \$2.49 billion from \$2.91 billion in 1986.

The company said Alaskan crude oil prices dropped 23.1% to an average price of \$15.51 a barrel during the quarter, compared with \$20.18 in the year-ago period.

The company gets 97% of its oil from Alaska.

Standard said first-quarter operating profit from exploration and production dropped 30% to \$327 million from \$464 million in 1986, while operating profit from refining and marketing—aided by lower crude oil costs—jumped sharply to \$72 million from \$5 million in the year-earlier quarter.

The company said that exploration expenses dropped 72% to \$43 million from \$152 million in 1986 because of lower dry-

	MARCH 31 QUARTER NET INCOME					
	1987		1986		%	
	in millions	per share	in millions	per share	chs.	
Arco	\$229	1.31	\$299	1.64	- 20	
Ashland	\$0.7	.02	\$41.6	1.20	- 98	
Standard	\$700	.85	\$253	1.08	- 21	

hole and support costs, and lower field geological and geophysical expenses, among

Separately, Standard disclosed that its directors have been discussing British Petroleum Co.'s proposed purchase of the company with BP representatives. The disclosure suggests that the stalemate over the takeover proposal may be easing, and it also raises the possibility that Standard may be able to extract a higher price from BP.

Standard said its directors haven't yet reached a decision on BP's tender offer of \$7.4 billion, or \$70 a share, for Standard's publicly held shares. The company said the seven members of its special committee, which consists of directors who are neither Standard officers nor affiliated with BP, met yesterday and will continue their discussions.

other reasons
 Robert B. Horton, chairman and chief executive officer, said that despite the lower first-quarter results, the company has "done well, even with the lower prices. Refining and marketing results improved, and the cost-cutting and restructuring we did last year is paying off."

As previously reported, Standard said the special committee would make a recommendation on the tender offer no later than yesterday. The company didn't elaborate on the postponement. BP already owns about 55% of Standard's common shares.

Standard said BP had extended the tender offer to 12:01 a.m. EDT May 5 from 12:01 a.m. next Wednesday.

In New York Stock Exchange composite trading yesterday, Standard closed at \$71, up 50 cents, on volume of 2.2 million shares.

Ashland Oil Inc.

The Ashland, Ky.-based company said higher crude oil prices and excess industry inventories contributed to an \$8.8 million operating loss in its second quarter ended

March 31.

Net income included a gain of \$9.5 million from the transfer of funds to an employee stock ownership plan.

The average number of common and common-equivalent shares outstanding increased to 32.1 million from 29.5 million in 1986.

Revenue dropped 11% to \$1.52 billion from \$1.71 billion in the 1986 quarter. Revenue excludes excise taxes.

Ashland, which had expected to report a decrease in earnings, said that it was hurt by the performance of its Ashland Petroleum Co. and SuperAmerica units. Ashland Petroleum posted an operating loss of \$34.6 million for the quarter, compared with operating profit of \$34.8 million in 1986. SuperAmerica, a chain of convenience and self-serve gasoline outlets, posted a \$51,000 operating loss during the quarter, compared with operating profit of \$17.5 million in the year-earlier period.

"While crude oil prices increased in line with OPEC policy, unseasonably warm weather and high product inventories throughout the industry kept product prices from increasing as rapidly," said John R. Hall, Ashland chairman and chief executive officer.

Ashland produces little crude. As a result, the company is hurt when prices for crude rise more rapidly than prices of gasoline and other refined products.

Mr. Hall nevertheless said that Ashland's profit margins are expected to pick up with the onset of the summer driving and road construction season.

Net income for the six months slid 70% to \$27.9 million, or 86 cents a share, from \$91.9 million, or \$2.68 a share, in the year-earlier six months. Revenue dropped 18% to \$3.02 billion from \$3.69 billion in the 1986 quarter.

Ashland shares closed yesterday at \$59.875, off \$1, in New York Stock Exchange composite trading.

Atlantic Richfield Co.

Los Angeles-based Arco said its profit decline resulted from lower margins that reflected the lag in the rise of product prices compared with crude-price in-

creases.
 Revenue declined 13% to \$3.74 billion from \$4.29 billion.

But Lodwick M. Cook, chairman, said he was "extremely pleased" with the company's performance because it "demonstrates Arco's earning power in a lower crude-price environment."

Reductions in Arco's exploration and operating costs helped earnings in the latest period, Mr. Cook said. Exploration expenses totaled \$75 million in the quarter, down from \$137 million a year ago.

Arco shares closed yesterday at \$84.50, up 25 cents, in New York Stock Exchange composite trading.

Texaco Profit Plunged 64% In First Quarter

Drop Reflects Oil Industry Conditions, Costs Tied To Pennzoil Litigation

A WALL STREET JOURNAL News Roundup

Texaco Inc. reported that net income fell 64% in the first quarter, reflecting depressed conditions in the oil industry as well as "direct and indirect costs" related to the company's legal battle with Pennzoil Co.

Net income fell to \$118 million, or 49 cents a share, from \$328 million, or \$1.37 a share. Revenue dropped 11% to \$8.5 billion from \$9.6 billion amid lower crude oil and petroleum product prices.

Texaco said the the quarter's results reflected the "rapidly changing market" for refining and marketing operations, where profit margins have been eroding in the face of higher crude oil prices. By comparison, refining and marketing margins rose a year earlier when crude oil prices were falling sharply.

Commenting on the Pennzoil litigation, James W. Kinnear, chief executive officer, said "along with the added legal fees and interest costs, the uncertainties surrounding judicial developments had a negative effect on the company's supply and trading operations. However, now that Texaco Inc. is free to pursue its court appeal without further threats of bond and lien pressures, many of those previous uncertainties have been removed."

Texaco, White Plains, N.Y., filed earlier this month under Chapter 11 of the federal Bankruptcy Code to forestall enforcement of a \$10.3 billion judgment against it awarded to Houston-based Pennzoil by a Texas court in 1985. Under Chapter 11, a company receives court protection from creditors while it works out a plan of reorganization.

Texaco said foreign-currency translation losses totaled \$7 million in the latest quarter, compared with gains of \$9 million a year earlier.

Exploration and production earnings in the U.S. fell to \$41 million from \$75 million a year ago, while manufacturing and marketing operations in the U.S. had a \$55 million loss, compared with year-earlier earnings of \$39 million. The loss reflected substantially lower petroleum product prices, Texaco said.

Outside the U.S., exploration and production earnings rose to \$163 million from \$108 million, because of lower expenses chiefly in Latin America and Europe, as well as reduced taxes. Foreign manufacturing and marketing operations earned \$61 million, down from \$262 million a year earlier, reflecting a sharp reduction in petroleum product prices in European areas.

Texaco said corporate and nonoperating expenses have been reduced, and that the latest quarter also benefited from a \$52 million reduction in estimated income tax liability applicable to prior years.

Capital and exploratory expenditures world-wide declined to \$364 million in the quarter from \$556 million a year earlier, because of exploration program cutbacks.

Texaco shares closed yesterday at \$33.75, up \$1.75, in heavy New York Stock Exchange composite trading.

*eroding
here
growing at
Std + ARCO*

Texaco Profit Plunged 64% In First Quarter

Drop Reflects Oil Industry Conditions, Costs Tied To Pennzoil Litigation

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Texaco shares closed yesterday at \$33.75, up \$1.75, in heavy New York Stock Exchange composite trading.

MEMORANDUM

State of Alaska

TO: Vincent D. Wright
Chief of Research

DATE: April 8, 1987

FILE NO.:

THRU:

TELEPHONE NO.: 465-2300

FROM: Bob Elliott *BE*
Research Analyst

SUBJECT: ANS/WTI Comparison
(Posted vs. Spot)

An analysis comparing the relationship between Alaska North Slope (ANS) SOHIO posted and spot prices with West Texas Intermediate (WTI) SOHIO posted and spot prices has been completed. Although the analysis was limited in scope (only 10 months of data was available), the results did show a consistency - the Alaska posted price was the first to drop and the last to increase except when the price level was used for apparent political purposes.

All of the following three charts use the same time period for ease of comparison. The three charts all illustrate four separate items, which are noted on each chart. Item I illustrates the ANS posted price dropping sharply while the WTI posted price was maintained for three weeks (during a time of sharply declining spot prices) and then stepped down over time. Item II, during a period of sharply increasing spot prices, shows the WTI posted price being stepped up over time, whereas the ANS posted price remains constant for two weeks until being increased sharply with the final WTI increase. Item III, again during increasing spot prices, shows ANS lagging WTI by two weeks in the second upward leg of the adjustment. Finally, Item IV shows the ANS posted price being increased while WTI remained the same. This was unique to the prior three items, and not surprisingly coincided with the ELF proceedings before the State legislature.

Finally, Chart 3 illustrates the differentials which exist between ANS/WTI posted prices and ANS/WTI spot prices. The results show WTI posted prices averaged approximately \$1.44 per barrel over ANS posted, whereas WTI spot prices averaged approximately \$1.09 per barrel over ANS spot during the period. The unique aspect of this chart was that, eventhough the WTI posted price was usually above ANS, the sharp downward spike during April 1987 represented the only time ANS exceeded WTI (\$17.75 vs. \$17.50), and coincidentally occurred at a time when tax proposals were being presented before the legislature.

BE/mkw

*Explain this time
when does it mean?*

CHART 1
ANS: PRICE COMPARISON
(POSTED VS. MAY 87 SPOT)

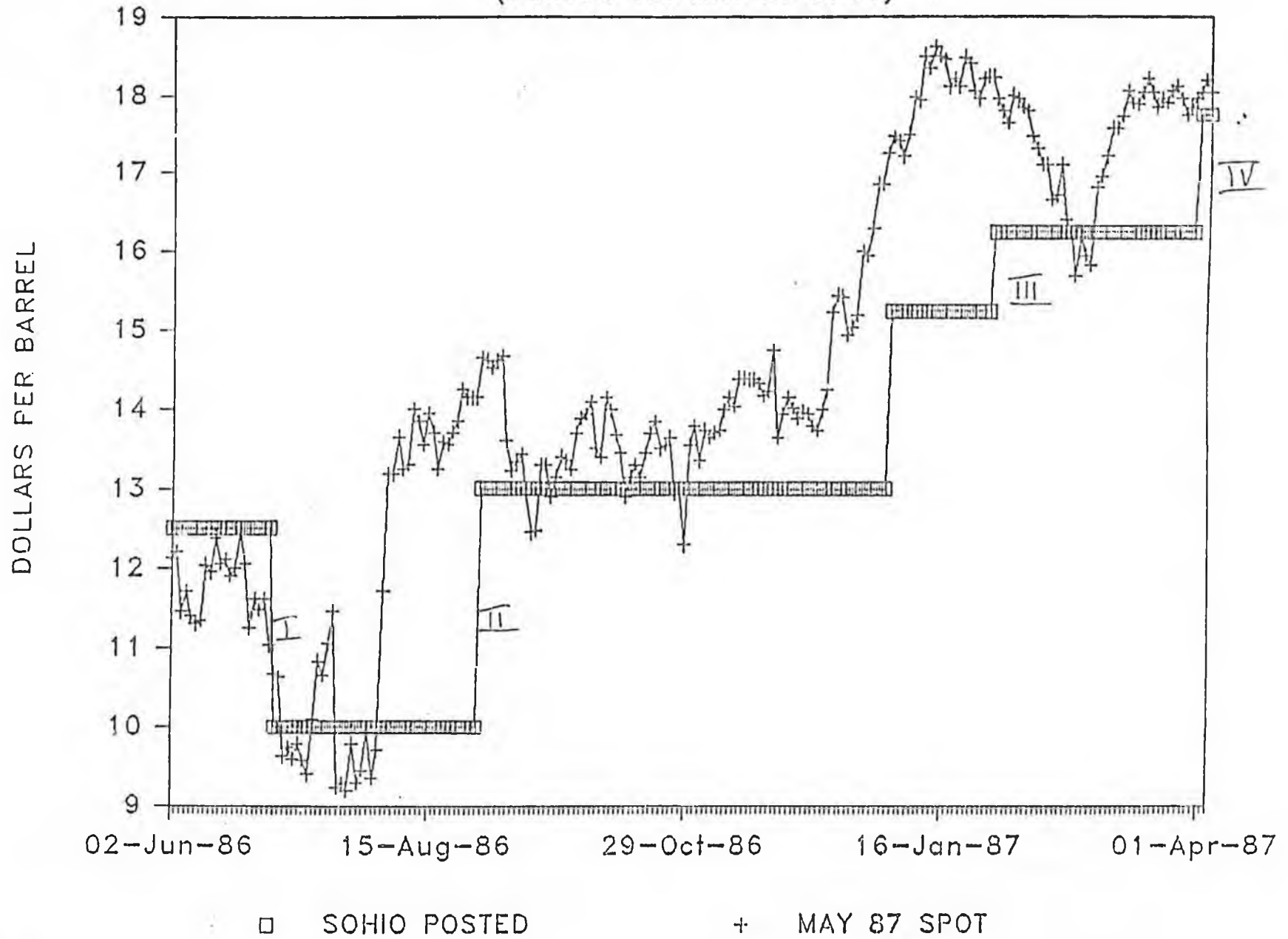


CHART 2

WTI: PRICE COMPARISON

(POSTED VS. MAY 87 SPOT)

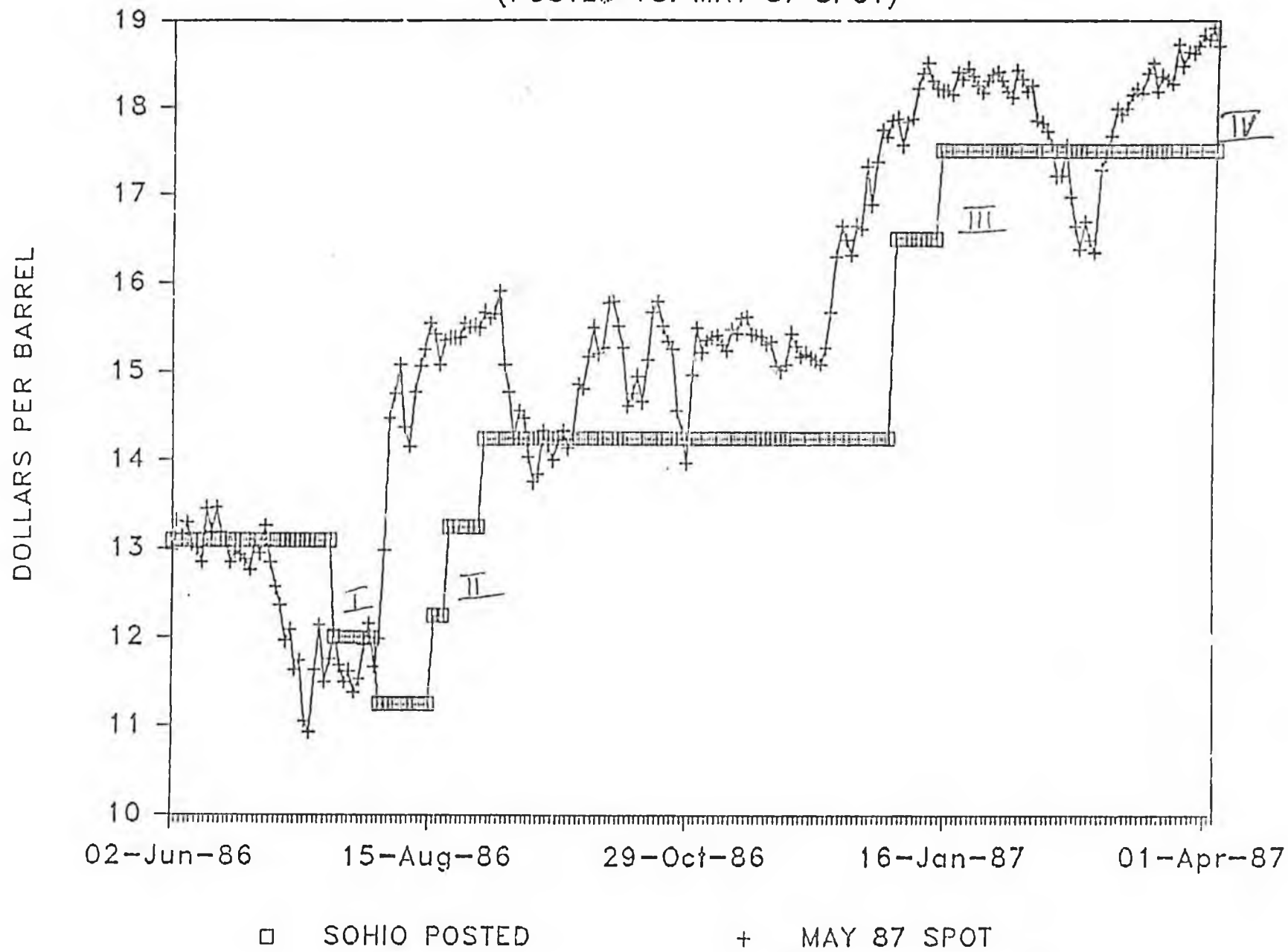
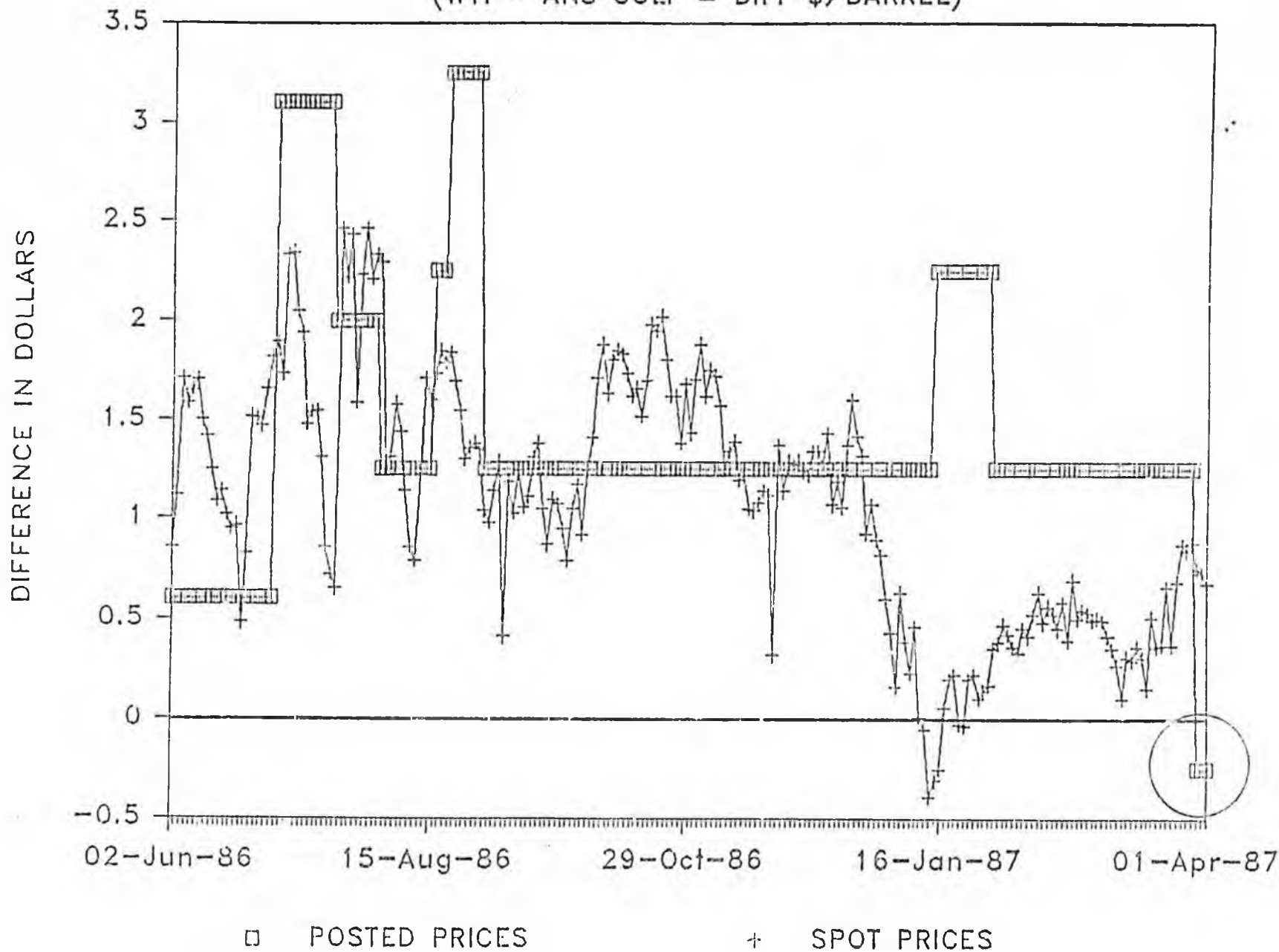


CHART 3

DIFFERENTIAL: POSTED VS. SPOT PRICES

(WTI - ANS GULF = DIFF \$/BARREL)



DRILL REPORT

North Slope development and exploration drilling shows a marked improvement in the first quarter of 1988 compared with 1987. As of mid-February, six drilling firms had a dozen rigs active on four North Slope fields. In the same period last year there were six rigs drilling and three performing workovers in the area.

Arco Alaska Inc. had four rigs drilling new wells and announced plans to double that number by year-end through a \$300-million production and exploration program. Of that amount, \$170 million will go to drilling-related activity.

Arco began the first of three planned exploratory projects in early February. Doyon Drilling's No. 9 rig is active on the Pipeline State No. 1 well. This is on a tract held jointly with Amerada Hess, about 25 mi. south of Prudhoe Bay and near the trans-Alaska pipeline.

The second probe will be at the north edge of the Prudhoe Bay Unit on an Arco-Exxon tract at Point McIntyre. Two wells have been drilled nearby on an Exxon tract. The Arco well will be designated Pt. McIntyre No. 3.

Also, Arco is to spud an exploratory well south of the Swanson River field in May or June. It is dubbed the Moose River No. 1 well.

Standard Alaska Production Co. had five rigs drilling new production wells as of mid-February. The company plans to spend \$398 million on Alaska projects in 1988 if the price of oil holds. Much of the expenditure will go to the Eileen West End project of the Prudhoe Bay field. The two-year program will employ two rigs for up to 72 wells, plus considerable pipeline and other support work for Alaska contractors.

Alaska United Rig No. 3 spudded the first Eileen well in February. This provided work for at least 100 people. Project employment will grow to about 300 this summer as construction activity increases.

Standard's planned development of the Niakuk field, offshore and west of the company's Endicott project, is budgeted at \$115 million. Of that, \$33 million is earmarked for drilling.

The field reportedly has proven reserves of 51 million bbl. Putting the field into production is expected to bring Alaska \$291 million in royalties and taxes.

Conoco Inc. has announced plans to launch a \$34-million Milne Point expansion project beginning this month. This will be a carefully phased project to include four new well pads, buildup and expansion of an existing

pad, 8.2 mi. of road, power lines, 10 new wells and flow lines.

Tom Painter, Conoco's Alaska manager, said if other partners agree to move on the project, work would progress slowly with a close eye on oil prices.

The Milne Point reservoir has proven more complex than expected. Conoco has shown it can produce 23,000 bbl./day of oil from existing wells. Present operations, however, reach the break-even point with oil at \$20 to \$22 per bbl.

Conoco and partners must further delineate the field and increase production to the original 30,000-bbl./day goal and that will take more wells.

Plans call for construction of drill pads G, H, I and J with adjacent reserve pits. The pads would be connected to each other and to the main Milne Point Road with 4.8 mi. of spine road.

Another 3.4 mi. of gravel road would provide permanent access to L pad, to be expanded on three sides and receive a 2-ft. gravel lift to meet drill operations requirements.

Other groups are proceeding with pre-drilling activities elsewhere. The Environmental Protection Agency and Army Corps of Engineers are identifying areas in the Col-

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(6) Terex 33-07 (1977), 40 tons



Caterpillar 988B, 7 cubic yard front end loader



P&H 9125, 140 tons



(2) Link Belt HSP8040 RT Crane (1980), 40 tons, 35-110' boom + 33' swingaway

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What's New in Construction Computer Software

A recent survey shows that less than 25 percent of construction firms are automated. Perhaps the main reason for this is the lack of computer awareness amongst contractors. With this in mind, what follows are some of the newer developments in computer applications for contractors.

Designing

Only recently has the price of computer-aided design become affordable for most construction firms. CAD packages are used to design anything from houses to air-conditioning ducts. VersaCAD has a system for use with its digitizer tablet. This allows various symbols used in the design to be stored and called up by simply selecting them from the tablet.

Once a design is complete, a bill of material can be produced with software packages available for the IBM PC and compatibles or Apple Macintosh.

Estimating

Preparing an estimate has never been easier. Wessex and Techsonix both have new packages to improve estimating accuracy and efficiency. Some of these packages start at under \$4,000. They allow the estimator to give instructions to the computer directly through a microphone. Blueprints can be fed into the computer by simply tracing the lines with a digitizer.

Engineering & Architecture

The new RT PC with its advanced graphics is well suited for engineering and architectural applications. It may soon be more common for architects to send designs directly from their computer to the computers at the contractor's office for bids, instead of sending the traditional blueprints.

Job Costing & Accounting

The first job costing systems were generally accounting packages that had been adapted for use by contractors. This situation has changed. There are now many packages designed specifically for construction firms.

These new packages feature integrated solutions that reduce even further the time and manpower needed to process paperwork.

Scheduling

When it comes to coordinating resources for a project, a computerized scheduling package is close to indispensable. One such package is called the Time Machine by Diversified Information Services. It can handle an unlimited number of resources for each activity and prints schedules on blueprints as well as on a color printer.

Excavating & Highway Construction

By simply entering in the present and desired land elevations, the new Quickdirt package automatically calculates the "cut and fill" quantities.

Paydirt, a software package from SpectraPhysics, allows landscapes and road designs to be directly fed into the computer from the blueprint by means of a digitizer. A laser attachment to the computer helps raise and lower the blade on a bulldozer doing the actual excavation.

The wealth of software available for construction firms has mushroomed as software manufacturers get a better understanding of the real needs of construction firms. The last question facing many contractors is not whether they need a computer solution, but how they can find the one that best meets their needs. With thousands of packages available, selecting the best solution can be

an ordeal. A new service called Softwhere? can help. Softwhere? maintains current information on more than 23,000 different software packages and provides unbiased reports. The company does not sell software packages. A contractor describes what he wants to accomplish and his budget, and for a flat fee of \$69, Softwhere? reports all the packages that meet his needs and where he can get them.

For free computer needs analysis form, send a stamped, self-addressed envelope to Softwhere? (Needs Analysis Form), P.O. Box 3336, Yuba City, CA 95992; (916) 741-3012. □



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The Thomas Glossary of Oil Jargon

Glossary of Oil Industry Terms (Alaskan Edition)

Stable tax climate — Any state/nation free of the socialist passion for gouging big industry. An effective arm-twisting term. The wise executive will use the old threat: "if you don't give us a 'stable tax climate,' we're going to take our \$7 billion and invest it in hogs or hoola hoops or whatever."

Stable regulatory climate — Any state/nation not controlled by fruitcakes only interested in things like clean water and clean air. Of course, the ultimate is no regulation at all. But, if regulation must be accepted, it is a job best left to the Boy Scouts.

Development Incentive — Special tax/regulatory breaks given to the oil industry in exchange for the honor of the industry's presence.

Consumption — The magic that makes the oil industry so much fun.

Finite Resource — A foolish notion; often used in anti-industry propaganda. As it relates to oil, this theory has never been proven. Glory be, the oil keeps flowing.

Conservation — Based on the "finite resource" sham. Some feel people should be urged, even forced, to conserve more and consume less. Conservation is as un-American as soccer, biathlons and solar panels.

Fair share — A term used frequently by the socialists, who believe that just because oil is being extracted from beneath public land, the public should get a sizable chunk of the money. Fair share antics can wreak havoc on a stable tax climate.

Alaska Permanent Fund — A bottomless pit of money where the fair-share crooks have taken all of the oil industry's money.

Permanent Fund Dividend — A bribe paid annually

Ralph Thomas



by the fair-share crooks to each person in the state.

Hugh Malone, Ben Grussendorf, Alaska House — Government sympathizers. Indian givers. Known to make proposals that would cut into oil industry profits. These men are dangerous.

Sen. Jan Faiks — Industry boys like to call her "The Big Easy." But Jan prefers to be known as "Oil's Fairy Godmother." For a small price, this oilfield princess will swing a big bat for industry.

Alaska Senate — "Easy Street." Also known as "Jan's Boys." A whole batch of low-priced, high-powered good buddies.

Local Hire — The virtuous practice of hiring workers close to home (i.e. Houston, San Antonio, Tulsa, etc).

Marginal well — Any oil well in North America. Only the Arabs have no marginal wells.

Economic Limit Factor — A dandy of a tax break known as ELF. The ticket to a stable tax climate. (See development incentive)

Alaska — A land where they still believe in ELFs.

RALPH THOMAS is managing editor of The Clarion.

• U.S. Senate •

Sen. Frank Murkowski
U.S. Senate
709 Hart Building
Washington, D.C. 20510
(202) 224-6665

Sen. Ted Stevens
U.S. Senate
522 Hart Building
Washington, D.C. 20510
(202) 224-3004

• House of Representatives •

Rep. Donald E. Young
House of Representatives
2331 Rayburn Building
Washington, D.C. 20515
(202) 225-5765

• Kenai Peninsula Office •

Joint Congressional Delegation
Trading Bay Professional Building
120 Trading Bay Rd., Suite 260
Kenai, AK 99611
283-5808

ALASKA OIL PRICES AND PRODUCTION

	Prudhoe Bay				Kuparuk			Milne Point			Lisburne				
	WHP	Exh B	In-value	(000 Bbl)	WHP	In-value	(000 Bbl)	WHP	Exh B	In-value	(000 Bbl)	WHP	Exh B	In-value	(000 Bbl)
81: 7	\$22.7	\$23.4	\$22.1	47,116.1											
8	\$22.7	\$23.0	\$22.0	47,124.2											
9	\$22.0	\$22.3	\$21.4	45,765.4											
10	\$22.0	\$22.2	\$21.4	46,917.3											
11	\$22.1	\$22.2	\$21.4	45,997.6											
12	\$21.8	\$21.9	\$21.2	46,763.3	\$19.7	\$19.3	1,091.5								
82: 1	\$21.2	\$21.5	\$20.5	47,980.7	\$19.7	\$19.3	2,503.6								
2	\$19.5	\$20.1	\$18.8	43,467.6	\$19.6	\$19.2	2,219.7								
3	\$18.4	\$18.8	\$17.7	47,439.3	\$18.0	\$17.6	2,856.8								
4	\$18.7	\$19.0	\$18.1	45,811.9	\$17.7	\$17.3	2,757.1								
5	\$18.9	\$19.0	\$18.3	47,745.2	\$17.9	\$17.5	2,896.6								
6	\$20.4	\$20.9	\$19.7	44,958.5	\$17.9	\$17.5	2,767.5								
7	\$20.4	\$21.0	\$19.7	48,037.7	\$17.8	\$17.4	2,680.0								
8	\$20.4	\$21.0	\$19.8	47,460.6	\$17.9	\$17.5	2,711.8								
9	\$20.4	\$20.9	\$19.7	46,216.7	\$17.7	\$17.3	2,669.0								
10	\$20.2	\$20.7	\$19.6	47,820.6	\$18.0	\$17.6	2,729.4								
11	\$19.8	\$20.1	\$19.2	45,223.3	\$18.5	\$18.1	2,791.0								
12	\$19.2	\$19.4	\$18.6	47,105.2	\$18.0	\$17.6	2,795.5								
83: 1	\$18.3	\$18.7	\$17.6	48,244.5	\$17.8	\$17.4	3,197.0								
2	\$17.4	\$17.7	\$16.8	43,167.5	\$16.6	\$16.2	2,838.7								
3	\$17.3	\$17.6	\$16.7	48,504.2	\$16.2	\$15.8	3,017.4								
4	\$17.3	\$17.5	\$16.6	46,543.9	\$16.2	\$15.8	2,966.8								
5	\$17.3	\$17.6	\$16.7	45,955.5	\$16.2	\$15.8	3,394.0								
6	\$17.4	\$17.6	\$16.7	45,365.2	\$16.0	\$15.6	3,239.7								
7	\$17.5	\$17.8	\$16.8	47,456.5	\$16.5	\$16.1	3,671.3								
8	\$17.8	\$18.3	\$17.1	47,305.9	\$16.4	\$16.0	3,282.6								
9	\$17.8	\$18.3	\$17.1	46,681.0	\$16.7	\$16.3	3,426.8								
10	\$17.7	\$18.2	\$17.1	48,382.2	\$16.8	\$16.4	3,310.9								
11	\$17.6	\$18.0	\$16.9	45,952.7	\$16.8	\$16.4	3,686.7								
12	\$17.7	\$18.0	\$17.0	47,231.7	\$16.8	\$16.4	3,828.9								
84: 1	\$17.5	\$17.8	\$16.8	48,311.5	\$16.7	\$16.3	3,983.4								
2	\$17.6	\$18.0	\$16.9	45,089.7	\$16.6	\$16.2	3,810.6								
3	\$17.6	\$18.0	\$16.9	42,889.4	\$16.6	\$16.2	4,241.7								
4	\$17.7	\$18.1	\$17.0	47,766.3	\$16.2	\$15.8	3,352.2								
5	\$17.7	\$18.1	\$17.0	49,258.5	\$16.6	\$16.2	3,372.5								
6	\$17.7	\$18.1	\$17.0	44,619.1	\$16.7	\$16.3	3,290.8								
7	\$17.8	\$18.2	\$17.1	47,259.5	\$17.0	\$16.6	3,349.2								
8	\$17.8	\$18.2	\$17.1	45,459.1	\$16.6	\$16.2	3,169.2								
9	\$18.0	\$18.4	\$17.3	47,677.5	\$16.9	\$16.5	3,359.3								
10	\$17.9	\$18.3	\$17.3	47,866.9	\$16.9	\$16.5	4,030.4								
11	\$18.0	\$18.2	\$17.3	46,779.7	\$17.1	\$16.7	4,922.3								
12	\$17.5	\$17.6	\$16.8	45,942.3	\$16.8	\$16.4	5,631.5								

ALASKA OIL PRICES AND PRODUCTION

	Prudhoe Bay				Kuparuk			Milne Point			Lisburne				
	WHP	Exh B	In-value	(000 Bbl)	WHP	In-value	(000 Bbl)	WHP	Exh B	In-value	(000 Bbl)	WHP	Exh B	In-value	(000 Bbl)
85: 1	\$17.0	\$17.1	\$16.3	43,993.1	\$16.2	\$15.8	5,297.2								
2	\$16.7	\$17.0	\$16.0	45,234.2	\$15.8	\$15.4	5,753.8								
3	\$16.8	\$17.0	\$16.1	49,430.0	\$16.0	\$15.6	6,581.1								
4	\$16.9	\$17.2	\$16.2	45,448.6	\$16.1	\$15.7	6,438.7								
5	\$16.9	\$17.2	\$16.2	50,053.1	\$16.0	\$15.6	6,771.3								
6	\$17.0	\$17.2	\$16.3	48,340.8	\$15.7	\$15.3	6,380.7								
7	\$16.8	\$17.1	\$16.1	47,943.0	\$15.4	\$15.0	6,724.5								
8	\$16.8	\$17.1	\$16.1	47,064.3	\$15.3	\$14.9	7,240.0								
9	\$16.9	\$17.1	\$16.2	47,552.9	\$15.6	\$15.2	7,132.7								
10	\$16.9	\$17.1	\$16.2	48,576.0	\$15.7	\$15.3	7,255.1								
11	\$16.9	\$17.1	\$16.2	45,883.5	\$16.1	\$15.7	6,429.4	\$14.1	\$14.3		205.5				
12	\$17.6	\$17.8	\$16.9	48,428.9	\$17.1	\$16.7	6,794.4	\$14.4	\$14.7		498.4				
86: 1	\$15.4	\$16.2	\$14.7	48,666.2	\$15.7	\$15.3	7,194.4	\$12.6	\$13.0		529.6				
2	\$10.9	\$11.9	\$10.2	44,385.0	\$9.5	\$9.1	6,937.9	\$8.3	\$8.7		478.8				
3	\$7.5	\$7.8	\$6.8	47,256.1	\$5.4	\$5.0	8,076.7	\$4.0	\$4.7		548.6				
4	\$5.8	\$6.1	\$5.1	44,391.3	\$4.1	\$3.7	8,366.9	\$4.5	\$5.0		479.6				
5	\$4.9	\$5.1	\$4.2	48,934.7	\$4.3	\$3.9	8,461.1	\$2.5	\$2.6		396.8				
6	\$4.4	\$4.6	\$3.7	46,272.0	\$4.5	\$4.1	8,099.9								
7	\$3.1	\$3.4	\$2.4	48,821.7	\$2.8	\$2.4	8,135.9								
8	\$3.7	\$4.2	\$3.0	46,763.1	\$3.4	\$3.0	7,479.2					\$3.7	\$4.2	\$3.0	175.6
9	\$5.6	\$5.7	\$4.9	44,422.4	\$5.5	\$5.1	7,062.3					\$5.6	\$5.7	\$4.9	7.3
10	\$5.7	\$5.8	\$5.0	49,807.0	\$5.3	\$4.9	8,010.8					\$5.7	\$5.8	\$5.0	118.4
11	\$5.8	\$5.9	\$5.1	47,031.4	\$5.5	\$5.1	7,745.5					\$5.8	\$5.9	\$5.1	298.7
12	\$6.9	\$7.3	\$6.2	45,850.9	\$6.6	\$6.2	8,471.5					\$6.9	\$7.3	\$6.2	675.0
87: 1	\$8.8	\$8.9	\$8.1	51,824.3	\$9.1	\$8.7	9,261.9					\$8.8	\$8.9	\$8.1	1,409.3
2	\$9.8	\$10.0	\$9.1	42,605.7	\$9.1	\$8.7	8,037.5					\$9.8	\$10.0	\$9.1	1,192.3
3	\$10.0	\$10.1	\$9.3	50,474.3	\$9.4	\$9.0	9,196.7					\$10.0	\$10.1	\$9.3	1,293.7
4	\$10.8	\$11.0	\$10.1	49,711.5	\$10.0	\$9.6	8,767.3					\$10.8	\$11.0	\$10.1	1,177.8
5	\$11.0	\$11.2	\$10.3	51,031.9	\$10.4	\$10.0	9,030.6					\$11.0	\$11.2	\$10.3	1,325.9
6	\$11.6	\$11.6	\$10.9	46,381.1	\$10.6	\$10.2	8,806.2					\$11.6	\$11.6	\$10.9	1,413.8
7	\$12.2	\$12.3	\$11.5	48,170.9	\$11.4	\$11.0	8,340.7					\$12.2	\$12.3	\$11.5	1,414.6
8	\$12.5	\$12.9	\$11.8	49,775.7	\$12.0	\$11.6	8,131.8					\$12.5	\$12.9	\$11.8	1,240.1

ELF ALTERNATIVES

DELAY ONLY

- \$87 million new revenue available in FY 88 (30th percentile).
- Revenue rises gradually through 1992, then drops abruptly by \$114 million when ELF again applies.
- Maintains Prudhoe tax at 15.0 percent.
- Kuparuk tax rate unchanged at 8.1 percent.
- No change in tax rates at Milne Point, Endicott, Lisburne, or other marginal fields.
- PEL adjustment unchanged. Falling oil prices could have magnified effect on severance tax revenue, i.e., 50 percent drop in wellhead price could produce 90 percent drop in revenue. State prohibited from asking for PEL adjustment if oil prices rise.
- Does not change provisions of current law allowing producers in large fields to gain tax rebates by adding wells producing at or near 300 barrels per day.

HOUSE SUBSTITUTE

- \$94 million new revenue available in FY 88 (30th percentile).
- Revenue rises gradually through FY 93, then declines gradually.
- Prudhoe tax rate reduced to 14.8 percent.
- Kuparuk tax rate increased to 11.7 percent.
- Decreases tax rates for Milne Point, Endicott, Lisburne, and other marginal fields. Eliminates tax for all existing Cook Inlet oil fields.
- Reduces chance that PEL adjustment would magnify effect of falling prices on severance tax revenue. State is allowed to petition for upward PEL adjustment.
- Eliminates negative tax rates on incremental revenue, but retains incentives for incremental production

Scan -
Gregg Erickson
prints to p. 12 -
Kupank has a
negative tax rate for
some wells under
extraordinary tax - Ned



OIL TAX QUIZ

MULTIPLE CHOICE:

1. How much profit does the oil industry make each day from North Slope oil and the pipeline?
 A. The industry is making no profit on the Slope.
 B. \$800,000 per day.
 C. \$2,200,000 per day.
 D. \$6,200,000 per day.
2. How do state and industry shares of North Slope oil income compare?
 A. State and local 80%/industry 5%/feds 15%.
 B. State and local 60%/industry 15%/feds 15%.
 C. State and local 45%/industry 35%/feds 20%.
 D. State and local 35%/industry 45%/feds 20%.
3. How many new jobs has the oil industry created on the North Slope since the ELF became effective at Prudhoe Bay in June of 1987?
 A. 2,400 jobs.
 B. 800 jobs.
 C. 200 jobs.
 D. Oil industry jobs on the Slope appear to have declined.
4. Why did the state adopt the 1981 oil tax bill?
 A. To give the oil industry a tax break.
 B. Because the oil industry sued the state over its separate accounting corporate income tax law, putting over one billion dollars of state revenue at risk.
 C. With the rise in oil prices, the state budget became so inflated that lawmakers wished to avoid the temptation posed by collecting the amount of oil taxes garnered under previous law.
 D. Because separate accounting was viewed as an unfair and inequitable tax law.

Oil Tax Quiz page 2

5. What commitment did the state make to the oil industry in 1981?
- A. No new taxes if the industry abandoned its lawsuit challenging the separate accounting law.
 - B. That the state would see them in court.
 - C. No deal was made, since no legislature can formally or informally bind a future legislature.
 - D. The legislature did not adopt the industry settlement proposal, and instead acted only to limit future liability.
6. What was the result of the oil industry's suit challenging the separate accounting law?
- A. The industry won in the state trial court but lost on appeal to the state Supreme Court.
 - B. The industry lost in state trial court, won on appeal to the state Supreme Court but lost in the U.S. Supreme Court.
 - C. The industry lost in the state courts, but won in the U.S. Supreme Court.
 - D. The industry lost in the state trial court, the state Supreme Court, and the U.S. Supreme Court.
7. What did Commissioner of Revenue Williams (now Director of Tax Planning for Standard) tell the legislature would be the revenue effects of the 1981 tax bill?
- A. A gain of \$67 million from FY 82-87.
 - B. A loss of \$141 million from FY 82-85 .
 - C. A loss of \$711 million from FY 82-85 .
 - D. A loss of \$1.001 billion from FY 82-87.
8. What were the revenue effects of the 1981 tax bill?
- A. A gain of \$67 million from FY 82-87.
 - B. A loss of \$141 million from FY 82-85.
 - C. A loss of \$711 million from FY 82-85.
 - D. A loss of \$1.001 billion from FY 82-87.

Oil Tax Quiz page 3

TRUE OR FALSE:

9. Alaska has the highest effective severance tax rate in the U.S.
10. In 1981, oil industry officials said the state's share of North Slope oil income should be the same as the oil industry's.
11. Prudhoe Bay is the most profitable oil field in the nation.
12. According to ARCO, only \$1.35 billion of \$10.5 billion spent on Alaska oil development was actually spent in Alaska (from 1980-86).
13. For every dollar the oil industry collects in Alaska, the industry reinvests only 18¢ in Alaska.

(Answers on following page.)

Oil Tax Quiz page 4

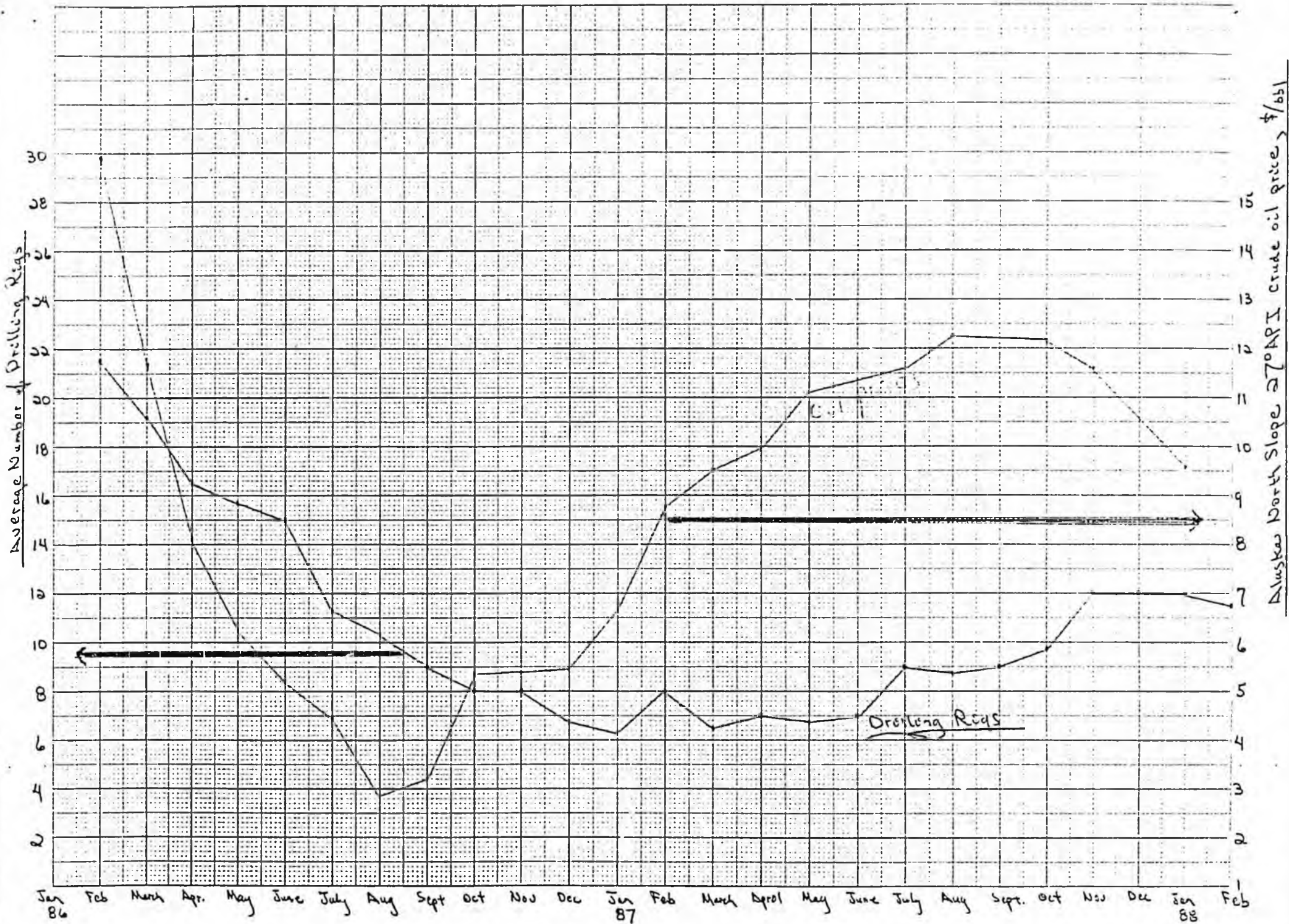
Correct Answers:

1. D. This equals over \$2 billion dollars per year. The figures are from *Petroleum Intelligence Weekly [PIW]*.
2. D. These figures also come from *PIW*.
3. D. Between the fourth quarter of 1986 and the fourth quarter of 1987, oil and gas industry employment on the Slope as estimated by the Department of Labor declined.
4. B. A is incorrect because legislators and Governor Hammond believed the changes made by the 1981 law were largely revenue neutral. They rejected industry settlement proposals that would have required foregoing several hundred million dollars in revenue. D is incorrect because only the oil industry believed the tax was unfair. See the answer to question 6 for what happened in the courts.
5. B, C & D are all correct.
6. D. In addition, the trial court required the industry to pay legal costs of \$1.5 million to the state for defending the industry's unsuccessful challenge.
7. B.
8. C & D are both correct.
9. False. If the oil fields in other states were transplanted to Alaska, most would pay no severance tax under either the present or proposed ELF. Currently, the effective severance tax rates in Wyoming and Louisiana are higher than Alaska.
10. True. Monte Taylor of Exxon and Richard Donaldson of Sohio made statements before the legislature expressing satisfaction with the idea of equal shares for the state and industry in testimony.
11. True.
12. True, according to figures in the January 1988 issue of ARCO's "On Top of ANWR."
13. True. During 1988 the industry is expected to collect \$3.85 billion in cash flow from Alaska, and reinvest about \$700 million.

Further information is available in the "The ELF: A Policy Perspective," an April 1988 briefing paper prepared by State of Alaska Division of Policy.

SAM

Hz count statewide
dropped from 21 to
about 6 - was about
12 last month.



Hospital needs help

Kodiak Island Hospital Advisory Board, Administration, Medical Staff, and departmental employees make every effort to bring our community the level of health care it should have to meet a growing population and industry. For the past seven years, the question of upgrading the present facility to meet federal and state, as well as community requirements, has been studied with costs and ability to meet the future needs a prime consideration. Three outside firms specializing in these areas have assisted us in reaching the following decision. A new facility would not only be considerably more cost effective, but would greatly benefit the hospital in their mission to provide these services as projected over future years.

The hospital has worked its way up through the waiting list for state assistance to fund this building. We now find ourselves in a three way tie for this funding. We have met every pre-funding, pre-construction requirement and we are now ready to go to bid for construction. There is some doubt in our minds about the ability of the other two communities to begin construction this year. We are now told this has become a political decision and funding will be provided on the effectiveness of the community in convincing the legislature and state administration, through our legislators, we do need a new hospital. It would be a great help if both individuals and organizations in the community would take a moment to call our legislators office and express their support for funding for this needed public owned facility.

Sen. Fred Zharoff, 465-3473

Rep. Cliff Davidson, 465-2487

In addition to telephone calls, messages can be sent to our legislators through the Legislative Information Office in the Borough Building: 486-8116.

This is a time that your comments will count in keeping Kodiak equipped with the ability to render good health care.

Thank you for your help.

Wilton White

Sensible oil policy

By CLIFF DAVIDSON

All Alaskans own Prudhoe Bay, the largest and most prolific oil field in U.S. history. We have derived tremendous benefits from its development: the Permanent Fund, many municipal improvements such as schools, roads, harbors, and hospitals, as well as government services for children, the elderly and the disabled.

However, the public share of the revenue from this field is presently declining, while the major oil companies are increasing their share and proclaiming their profitability in a tough oil market. For this fiscal year, about \$185 million has been directly transferred from our Alaskan treasury to the corporate treasuries of several major international oil companies through premature application of the so-called "ELF" tax break.

All over the state, people who need school improvements and municipal services wonder why the Legislature continues to allow a reduction in oil and gas taxes when our state revenues are in precipitous decline.

Part of the explanation is that the Legislature scheduled the tax break back in 1981, when oil prices were rising and it was thought that Prudhoe Bay would be in decline by 1987. Today it is clear that the industry will continue to operate, quite profitably, if the ELF is repealed. Yet, the State Senate has refused to act on an oil tax bill.

Governor Cowper and the House of Representatives have both

fields. Last year the House
nor's request, that did two
* prevented large tax b
Kuparuk, where tax incent
* provided a new tax
known field in Alaska, in
Lisburne, and Milne Poi
cause it was uneconomic.

This approach makes
that Atlantic Richfield is
in the world - and guess
oil? From Kuparuk and P
essary for these oil fields.

The chief executive o
the company's profits are
has also publicly reporte
while reducing productio
tions of a company produ
ing economically.

Meanwhile, British Pe
of Standard Oil. Now it
98% of its oil production

And, Kuwait's nation
20% of BP. These aren't
the profitability and pote

Some industry repres
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Kodiak
daily mirror
ISSN-0740-2112



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BLOOM COUNTY



**DAILY AVERAGE CRUDE OIL PRODUCTION
PER PRODUCING OIL WELL**

P.A.D. DISTRICT NUMBER IV
P.A.D. DISTRICT NUMBER V
UNITED STATES

(Barrels)

*PRODUCTION PER
WELL IS EVER
DECREASING -
PARTLY DUE TO
ALASKA'S WELL-
BASED E.L.F.?*

Year	P.A.D. District Number IV				Weighted Average District IV	P.A.D. District V			Weighted Average District V	United States
	Colorado	Montana	Utah	Wyoming		Alaska	California	Arizona Nevada, Washington		
1921	4	44	...	37	35	...	31	...	31	5
1922	4	47	...	42	41	...	42	...	42	5
1923	4	29	...	53	49	...	77	...	77	7
1924	14	21	...	42	38	...	55	...	55	7
1925	38	19	...	26	25	...	58	...	58	7
1926	62	25	...	21	23	...	54	...	54	7
1927	47	14	...	16	17	...	56	...	56	8
1928	38	10	...	17	16	...	59	...	59	8
1929	27	9	...	15	14	...	76	...	76	8
1930	21	6	...	14	12	...	66	...	66	7
1931	20	6	...	12	11	...	58	...	58	7
1932	16	5	...	12	10	...	55	...	55	7
1933	16	4	...	9	8	...	43	...	43	8
1934	16	7	...	10	9	...	41	...	41	7
1935	20	2	...	11	11	...	45	...	45	8
1936	24	11	...	12	12	...	48	...	48	9
1937	20	10	...	16	14	...	49	...	49	10
1938	20	9	...	16	13	...	49	...	49	9
1939	20	9	...	18	15	...	42	...	42	9
1940	17	10	...	20	17	...	40	...	40	10
1941	26	11	...	23	19	...	37	...	37	10
1942	35	10	...	31	22	...	36	...	36	9
1943	36	10	...	26	20	...	38	...	38	10
1944	43	11	...	24	20	...	40	...	40	11
1945	58	9	...	25	20	...	41	...	41	11
1946	84	9	...	26	23	...	38	...	38	11
1947	80	10	...	30	27	...	36	...	36	12
1948	67	8	...	32	26	...	35	...	35	13
1949	86	9	...	79	27	...	37	...	37	11
1950	84	7	...	102	32	...	31	...	31	12
1951	91	8	...	85	34	...	33	...	33	13
1952	85	8	...	78	38	...	32	...	32	13
1953	81	n	...	72	44	...	31	...	31	13
1954	73	10	...	64	45	...	29	10	29	12
1955	68	11	...	87	44	...	28	58	28	13
1956	74	15	...	61	44	...	26	58	26	13
1957	69	19	...	35	46	...	25	34	25	13
1958	60	21	...	124	47	...	24	51	24	12
1959	61	22	...	165	48	...	23	168	23	12
1960	64	24	...	136	49	...	22	300	22	12
1961	65	25	...	95	50	...	385	89	22	12
1962	59	23	...	104	42	...	540	33	21	12
1963	54	24	...	109	50	...	635	56	21	13
1964	50	21	...	83	48	...	560	58	21	13
1965	50	24	...	80	47	...	508	44	22	13
1966	54	27	...	76	44	...	690	60	24	14
1967	51	25	...	66	44	...	896	274	29	15
1968	48	40	...	72	44	...	1,010	355	30	16
1969	43	34	...	72	47	...	1,050	191	32	17
1970	38	33	...	70	46	...	1,423	...	29	19
1971	40	25	...	74	40	...	1,190	127	28	18
1972	48	29	...	81	43	...	1,011	130	26	19
1973	54	27	...	62	51	...	1,032	107	27	18
1974	50	31	...	88	44	...	848	85	26	18
1975	44	29	...	110	39	...	957	73	24	17
1976	45	27	...	79	32	...	912	67	32	16
1977	36	27	...	105	37	...	1,593	106	50	16
1976	31	25	...	66	38	...	3,358	139	48	17
1979	26	23	...	56	36	...	3,502	134	62	18
1980	23	22	...	48	34	...	2,518	132	56	17
1981	29	21	...	46	31	...	2,299	83	55	16
1982	27	20	...	39	28	...	2,231	72	68	15
1983	17	17	...	50	28	...	2,550	84	57	14
1984	15	19	...	53	29	...	2,691	85	58	14
1985	15	19	...	57	29	...	1,868	121	59	14
1986	15	19	...	58	28	...	1,683	150	67	14

* Data not available.

AUTHORITY: UNITED STATES DEPARTMENT OF ENERGY
"WORLD OIL"



file

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Media Communications
Post Office Box 100360
Anchorage, Alaska 99510-0360

news

for release

IMMEDIATELY

For further information contact
Susan Andrews at (907) 265-6847

ARCO ANNOUNCES EARNINGS
FOR FIRST QUARTER OF 1987

LOS ANGELES, Ca., April 23 -- ARCO today reported earnings of \$239 million or \$1.31 per share for the first quarter of 1987. Results for the same period a year ago were \$299 million, or \$1.64 per share.

Lodwick M. Cook, chairman of the board and chief executive officer, said, "We are extremely pleased with our first quarter performance since we believe it demonstrates ARCO's earning power in a lower crude price environment. Although crude prices in the first quarter were below the first quarter of 1986, the effect on upstream earnings was almost entirely offset by lower exploration and operating costs. Crude oil prices have improved since the fourth quarter of last year, and we expect our performance to improve further as prices stabilize at today's levels."

ARCO's average price for domestic crude oil was \$11.21 per barrel in the first quarter, compared with \$14.14 per barrel in the same period last year. Average domestic natural gas prices fell to \$1.64 per thousand cubic feet, versus \$2.23 last year, and natural gas liquids prices averaged \$9.97 per barrel, versus \$12.40 in the 1986 first quarter.

First quarter earnings also included a \$10 million net after-tax gain on the sale of certain Lower 48 oil and gas properties, after restructuring costs, as well as a \$19 million after-tax gain related to the sale of a corporate asset. These were offset, however, by a \$35 million after-tax charge related to the previously announced early redemption of certain debt issues.

-more-

Consolidated sales and other operating revenues for the first quarter of 1987 were \$3,744 million, compared to \$4,287 million for the same period a year ago.

After-tax earnings for worldwide oil and gas operations were \$203 million in the first quarter of 1987 (including the \$10 million net gain relating to the sale of Lower 48 producing properties), versus \$202 million in the 1986 first quarter.

Exploration expenses totaled \$75 million for the quarter, compared with \$137 million in the same period last year.

Total production of crude oil and natural gas liquids averaged 740,600 barrels per day in the current first quarter versus 736,400 barrels per day a year ago. A decline in Lower 48 production due to property sales and natural field decline was more than offset by substantially higher Alaskan and international production. This included the first full quarter of production from the new Lisburne field, as well as increased production from Kuparuk.

Natural gas sales increased to 1,579 million cubic feet per day from 1,547 million cubic feet per day in the first quarter of 1986. The increase is attributable to higher foreign natural gas sales primarily from the start up in late 1986 of the Thames gas field in the North Sea. This was partially offset by a decline in Lower 48 fields as a result of property sales and reduced demand due to an unusually warm winter.

After-tax earnings from coal operations were essentially flat at \$14 million versus \$15 million last year.

"In our downstream operations, weaker margins for petroleum products reduced earnings for refining and marketing and integrated petroleum processing operations compared to last year's first quarter, when margins were particularly strong," said Cook. "However, on the positive side, ARCO Chemical Company had significantly higher earnings in the first quarter and all other operating segments continued their solidly profitable performances."

First quarter 1987 after-tax earnings from refining and marketing operations amounted to \$25 million versus \$90 million in the first quarter of 1986. The decline is primarily attributable to reduced margins brought about by a lag in the rise in product prices compared to crude price increases in the first quarter.

After-tax earnings from transportation operations were \$86 million for the current quarter, compared with \$87 million last year. The impact of the lower Trans Alaska Pipeline tariff was nearly offset by lower operating costs.

ARCO Chemical Company (intermediate chemicals and specialty products) had an outstanding performance in the first quarter. Volumes and margins improved for the Company's oxygenated products, resulting in after-tax earnings of \$61 million, versus \$26 million in the same period last year.

Page 4

Lyondell Petrochemical Company (integrated petroleum processing) had after-tax earnings of \$22 million compared with \$32 million in the first quarter of 1986. Lower margins for refined products and petrochemicals were partially offset by \$5 million of various nonrecurring items.

ARCO's annualized return on stockholders' equity was 18 percent in the first quarter of 1987, compared to 21.9 percent in the same period of 1986.

#

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ARCO
FINANCIAL AND STATISTICAL DATA
(Millions of Dollars Except Per Share Amounts)

	<u>Three Months Ended</u> <u>March 31, 1987</u>	<u>Three Months Ended</u> <u>March 31, 1986</u>
Sales & other operating revenues (including excise taxes)	\$3,744 <u> </u>	\$4,287 <u> </u>
Income before income taxes	\$ 397	\$ 608
Provision for taxes on income	<u>158</u>	<u>309</u>
Net income	\$ 239 <u> </u>	\$ 299 <u> </u>
Income per share:		
Net income	\$ 1.31	\$ 1.64
<u>After-tax segment earnings</u>		
Resources:		
Oil and Gas	\$ 203	\$ 202
Coal	14	15
Products:		
Refining and Marketing	25	90
Transportation	86	87
Intermediate Chemicals & Specialty Products	61	26
Integrated Petroleum Processing	22	32
Unallocated expenses and other operations	(40)	(48)
Interest	<u>(132)</u>	<u>(105)</u>
Net income	\$ 239 <u> </u>	\$ 299 <u> </u>
Average common shares outstanding including equivalents (millions of shares)	183.0	182.2
Percent return on average shareholders' equity (annualized)	18.0%	21.9%

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For further information
contact Susan Andrews, 265-6847

ARCO ANNOUNCES EARNINGS FOR
THIRD QUARTER, NINE MONTHS

LOS ANGELES, Ca., October 26 -- ARCO reported net income of \$315 million or \$1.71 per share for the third quarter of 1987, an increase of 209 percent from the \$102 million or \$.56 per share earned in the third quarter of 1986.

Lodwick M. Cook, chairman of the board and chief executive officer, said: "Crude oil prices were higher in the third quarter compared to a year ago, leading to significantly improved results from our oil and gas operations. Results also benefited from higher earnings from ARCO Chemical Company and higher crude oil and natural gas liquids production. These increases were partially offset by lower earnings from refining and marketing operations, resulting from significantly lower margins for petroleum products."

For the first nine months of 1987, net income was \$884 million or \$4.82 per share compared with \$551 million or \$3.03 per share in the same period of 1986.

Sales and other operating revenues totaled \$4.4 billion for the third quarter of 1987, compared with \$3.5 billion in 1986. For the nine month period, sales and other operating revenues amounted to \$12.2 billion, versus \$11.4 billion in the first nine months of 1986.

-more-

After-tax earnings for worldwide oil and gas exploration and production operations rose to \$235 million in the current third quarter compared to \$41 million in the same period last year. The improved results are primarily attributable to higher crude oil and natural gas liquids prices, along with higher production volumes.

ARCO's average price for domestic crude oil was \$14.02 per barrel in the third quarter, compared with \$7.04 per barrel in the third quarter of 1986. Average domestic natural gas liquids prices were \$11.11 per barrel versus \$7.75 per barrel in the 1986 third quarter. Average domestic natural gas prices were \$1.61 per thousand cubic feet versus \$1.67 per thousand cubic feet in the same period last year.

Worldwide production of crude oil and natural gas liquids averaged 728,700 barrels per day in the current third quarter versus 715,200 barrels per day a year ago. The increase was due to higher production from the North Slope of Alaska, partially offset by lower production from the Lower 48.

Average domestic natural gas sales were relatively flat at 1,147 million cubic feet per day versus 1,124 million cubic feet per day in the third quarter of 1986. Foreign gas sales averaged 79 million cubic feet per day compared to 89 million cubic feet per day last year. Higher U.K. production associated with the start-up of the Thames field in the fourth quarter of 1986 was more than offset by lower production from Indonesia and the

Netherlands.

Worldwide exploration expenses amounted to \$96 million for the quarter, compared with \$70 million in the same period last year.

Coal operations reported after-tax earnings of \$18 million in the third quarter of 1987 versus \$32 million in the third quarter of 1986. The 1986 results included an after-tax gain of approximately \$15 million for the sale of the company's interest in an Indonesian coal venture.

After-tax earnings for refining and marketing operations declined to \$30 million in the third quarter of 1987 from \$94 million last year due primarily to lower margins for petroleum products caused by a lag in the rise of product prices compared to crude prices.

After tax earnings for transportation operations were up slightly to \$87 million from \$84 million last year.

The intermediate chemicals and specialty products segment had a strong performance in the third quarter due primarily to higher margins for styrene. This segment reported after-tax earnings of \$73 million versus a loss of \$7 million in the third quarter of 1986, when results included a \$44 million after-tax charge associated with the sale of certain chemical assets.

After-tax earnings for Lyondell Petrochemical Company (integrated petroleum processing operations) amounted to \$23 million in the current third quarter versus \$24 million in the same period last year. Margins for refined products fell sharply,

but this was nearly offset by higher margins and volumes for petrochemical products.

After-tax interest expense declined slightly to \$125 million from \$129 million in last year's third quarter as a result of lower debt levels offset by lower capitalised interest.

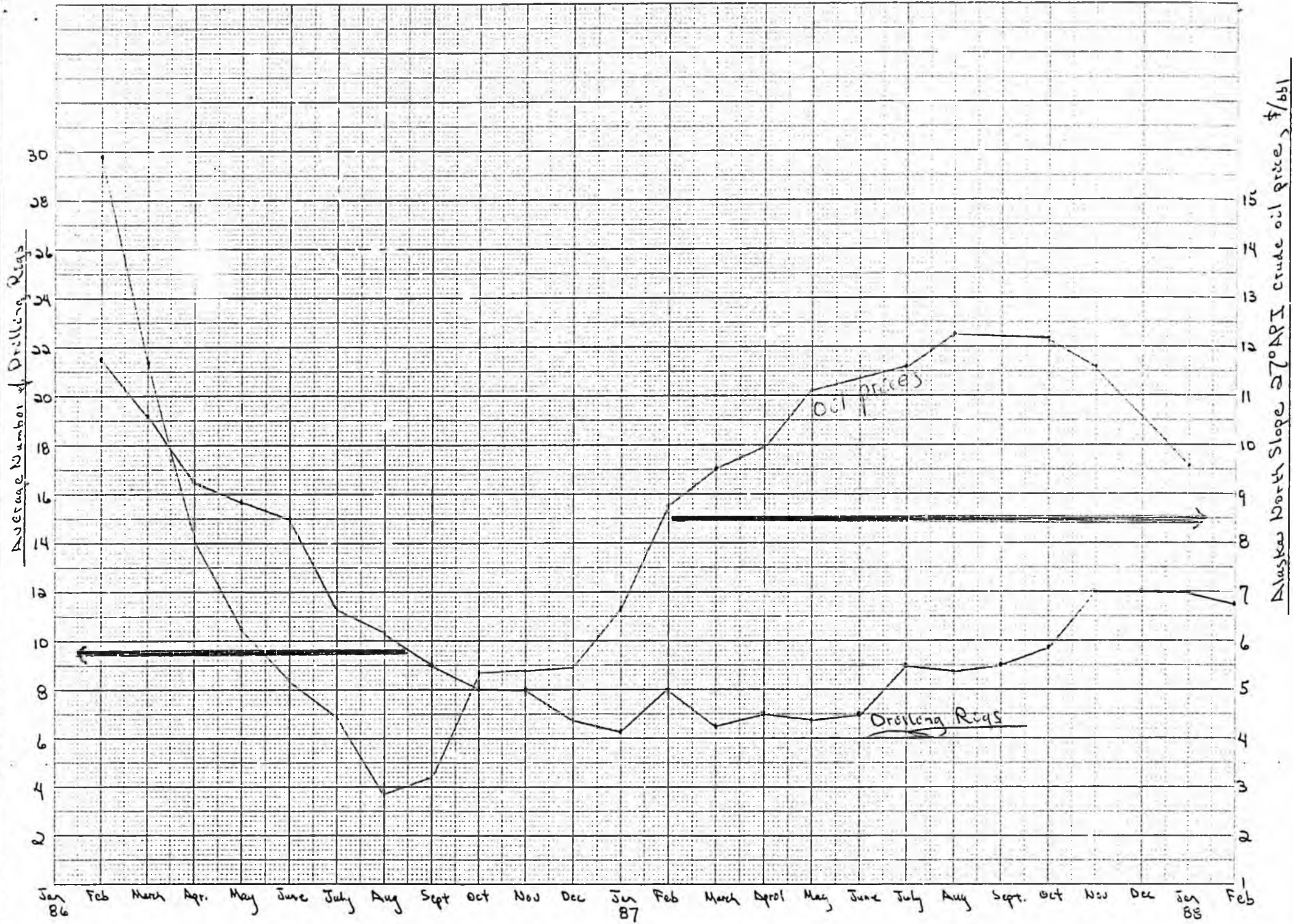
ARCO's annualized return on stockholders' equity for the first nine months of 1987 was 21.4 percent, compared with 13.6 percent a year ago.

* * * *

ATLANTIC RICHFIELD COMPANY
FINANCIAL STATISTICAL DATA
(Millions of Dollars Except Per Share Amounts)

	<u>THREE-MONTHS ENDED</u> <u>SEPTEMBER 30</u>		<u>NINE-MONTHS ENDED</u> <u>SEPTEMBER 30</u>	
	<u>1987</u>	<u>1986</u>	<u>1987</u>	<u>1986</u>
Sales & other operating revenues (including excise taxes)	\$ 4,397 *****	\$ 3,532 *****	\$12,244 *****	\$11,368 *****
Income before income taxes	671	222	1,568	1,120
Provision for taxes on income	<u>256</u>	<u>120</u>	<u>684</u>	<u>559</u>
Net income	\$ 315 *****	\$ 102 *****	\$ 884 *****	\$ 551 *****
Earned per share	\$ 1.71	\$ 0.56	\$ 4.82	\$ 3.03
<u>After-tax segment earnings</u>				
Resources:				
Oil and gas	\$ 235	\$ 41	\$ 681	\$ 242
Coal	18	32	50	62
Products:				
Refining and marketing	30	9	100	305
Transportation	87	84	256	262
Intermediate chemicals & specialty products (including ARCO Chemical Company)	73	(7)	204	60
Integrated petroleum processing (Lyondell Petrochemical Company)	23	24	76	112
Unallocated expenses and other operations	(26)	(37)	(99)	(132)
Interest	<u>(125)</u>	<u>(129)</u>	<u>(384)</u>	<u>(360)</u>
Net income	\$ 315 *****	\$ 102 *****	\$ 884 *****	\$ 551 *****
Percentage return on average stockholders' equity (annualized)	22.2%	7.6%	21.4%	13.6%
Average common shares outstanding including equivalents (millions of shares)	183.6	182.2	183.3	182.1

10/22/87





ALASKA REPORT

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NOV 20 1987

Vol. 33, No. 46
11-18-87

Texaco, Arco, Standard Set Drilling Plans for 1988

ANCHORAGE, ALASKA

DRILLING PLANS being made now will increase the active rig count in Alaska next year as Texaco Inc, Arco Alaska and Standard Alaska Production plan increased drilling activity for 1988.

Texaco has filed plans with the state indicating that it will drill up to three exploratory wells south of Kuparuk River field near Oliktok next year. Plans call for construction of an ice road and drilling pad to begin later this month and the first well, the Wolfbutton #1, to be spudded in early January.

Following completion of drilling at the first location, construction would then begin on a second ice road and the second and third wells would then be spudded simultaneously toward the end of February.

Texaco said drilling operations at the second and third wells would be completed in April and the sites demobilized by May 15. To date, contracts for the drilling rigs for the wells have not been awarded.

Arco Alaska also plans to drill an exploratory well on the North Slope next year and has dubbed the well the Prudhoe Pipeline #1. The company plans to drill the well at a location about 25 miles south of Deadhorse and has

contracted Doyon Drilling's Rig #9 for the work.

Standard Alaska Production currently is reviewing bid proposals for two drilling rigs the company plans to use to drill an unspecified number of wells for the Eileen/West End project on the west side of Prudhoe Bay field. The development wells will be drilled into the Sadle-rochit formation to produce an estimated 110 million bbls of crude from about 500 million bbls in place. The drilling is designed to produce oil partially cut off from the main Prudhoe Bay field reservoir by geologic formations.

Standard originally had planned to begin drilling there early this year, but slumping oil prices put the project on hold. Now, with oil prices in the \$18-\$20 range, Standard plans to begin drilling early next year and begin production next summer. Drillsites already have been built and the drilling contracts are expected to be awarded next month.

Current exploratory activity in the state has Tenneco Oil drilling its Aurora well in the Beaufort Sea off the coast of the Arctic National Wildlife Refuge. No information on the well is available as Tenneco has labeled the well "an extremely tight hole."

In North Slope development work, Standard Alaska is drilling at 13,160 ft at the P-24 and setting a cement plug at 14,640 ft at the K-33, both in Endicott field.

In Prudhoe Bay field, crews are setting a cement plug at an unspecified depth at Standard's K-10, while bad weather has hampered efforts to move Alaska United Drilling's Rig #2 to the new E-23 location following the completion of drilling activity at the E-27 last week.

Arco Alaska is drilling at 9,570 ft at the 3H-3 in Kuparuk River field and has sidetracked the hole at 7,100 ft at the DS 18-13 in Lisburne field. Drilling at the latter site has reached the 7,984-ft mark. In Lisburne field, crews are testing the blowout preventer at Arco's L2-8 prior to setting casing at 11,503 ft.

In Cook Inlet, Amoco Production is setting casing at 3,525 ft at the GP37 on the Anna platform, while Marathon Oil is cleaning cement out of seven-inch liner set at 11,748 ft and is preparing to complete the M-25 drilled from the Steelhead platform.

Onshore on the Kenai Peninsula, Unocal is continuing testing operations at the Cannery Loop #4.

Petroleum Information

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E1-1

EXHIBIT E-1

PLAN OF DEVELOPMENT AND OPERATION FOR LANDS
OUTSIDE THE INITIAL PARTICIPATING AREAS
PRUDHOE BAY UNIT AGREEMENT
STATE OF ALASKA

Lands within the Unit Area that are not in the initial Participating Areas shall be developed and operated pursuant to the Plan of Development and Operations ("the Plan") described herein, to wit:

A. Hydrocarbon-productive Reservoirs have been discovered within the Unit Area in the Lisburne, North Prudhoe Bay (Permo-Triassic) and Kuparuk River formations, and these Reservoirs extend to lands in the Unit Area beyond the initial Participating Areas. As of the effective date of this Unit, these Reservoirs have not been reasonably proven to be capable of producing unitized substances in sufficient quantities to justify Working Interest Owners in developing and producing them. However, additional wells and studies are planned from 1977 through 1982 to further evaluate these Reservoirs prior to the formation of Participating Areas. The Plan for these other reservoirs include plans for the drilling of additional wells both within and outside the boundaries of the initial Participating Areas. Further, any well drilled on any part of a lease, any portion of which lease is included in the Unit Area, shall be deemed a well drilled in satisfaction of this Exhibit E-1 regardless of whether or not such well is located in the Unit Area; provided, that it is shown to the satisfaction of the Director that the bottom-hole target of the well will provide a reasonable geologic test or geologic information significant to Unit Operations.

1. *Lisburne Reservoir.*

a. *Work in Progress.* Three Lisburne test wells (A.R.Co./Exxon Gull Island 2; BP Sag Delta 35-12-16; and BP Sag Delta 10-11-16) were commenced in January 1977, and drilling operations in connection therewith should be completed by the end of 1977.

b. *Studies.* For the period January 1, 1978 to July 1, 1982, detailed geological, geophysical, and engineering studies

will be carried out by each affected Working Interest Owner to evaluate the structure, areal distribution, and continuity of hydrocarbon-bearing reservoirs, as well as the productive capability of such reservoirs within the Lisburne carbonate section. Based on these studies, the economic feasibility of further Lisburne Reservoir(s) development will be determined.

c. *Further Drilling.* For the period January 1, 1978 to July 1, 1982, Working Interest Owners plan to drill three (3) wells in addition to the above for further appraisal and delineation of the Lisburne Reservoir(s). Since the location of such wells will, in part, be dependent upon the results of the Lisburne wells described in paragraph (a) above, and some of the studies described in paragraph (b) above, the locations are undesignated at this time.

2. *Kuparuk and North Prudhoe Bay (Permo-Triassic) Reservoirs.*

a. *Wells.* Two undesignated wells are planned to evaluate the Kuparuk and North Prudhoe Bay (Permo-Triassic) Reservoirs prior to July 1, 1982.

b. *Studies.* Prior to July 1, 1982, technical studies including detailed Kuparuk stratigraphy and lithofacies work, and combined geological-geophysical structural analysis for the Kuparuk and North Prudhoe Bay (Permo-Triassic) Reservoirs are planned. Based on these studies, the economic feasibility of further development will be determined.

At least two of the wells described in paragraph (1.c) and (2.a) hereof are planned to be drilled prior to July 1, 1981.

The terms of this Plan shall cover the time period from the Effective Date of the Prudhoe Bay Unit Agreement through June 30, 1982.

Unit Operators will continue to obtain approvals and permits for Unit Operations as required by State laws, regulations and/or State Oil and Gas Lease Stipulation (Attachment No. 1 hereto).

Commencing July 1, 1978, and each year thereafter, Unit Operators will file progress reports describing operations under this Plan for the preceding twelve (12) month period.

E1-3

ATTACHMENT NO. 1 TO EXHIBIT E-1

OIL AND GAS LEASE STIPULATION

I. Prior to commencement of any operations on the lease, the lessee shall obtain written approval from the Director, Division of Lands for the location of all operations and type of facilities in order to protect fish and wildlife, prevent pollution, and minimize surface damage. This stipulation does not affect the requirement that the lessee obtain approval of the Alaska Oil and Gas Conservation Committee pursuant to AS 31 and the regulations adopted thereunder.

The lessee shall:

(a) Submit, in triplicate, at least 30 days prior to beginning any operations on this lease, to the Director, Division of Lands, a plan of operation that will include statements, maps, or drawings relating to:

(1) The methods to be used to assure proper disposal of mud, oily waste, garbage, refuse, and other pollutants.

(2) The design of pollution prevention facilities.

(3) The location of any proposed well or wells, buildings, rights-of-way, airstrips, and storage facilities.

(4) The location and design of material sites.

(5) Measures to be taken to prevent erosion (particularly of roads and material sites) and damage to watersheds and vegetation.

(6) The location of proposed seismic activities.

(b) Keep the operational plan current in all respects.

II. The lessee shall:

(a) Comply with the provisions of the approval and do all things reasonably necessary to prevent or reduce to the fullest extent scarring and erosion of the lands, pollution of the water resources, and damage to the watershed. Should activities of the lessee cause damage to the watershed or pollute the water resource, the lessee agrees to repair such damage in a manner acceptable to the Director.

(b) Allow authorized personnel of the Department of Natural Resources and the Department of Fish and Game to enter the premises to inspect the installations and operation activities of the lessee.

(c) Prior to the beginning of operations, appoint and maintain, at all times during the term of the lease, a local agent upon whom may be served written orders or notices respecting matters contained in these stipulations and to inform the authorized officer in writing of the name and address of such agent. If a substitute agent is appointed, the lessee shall immediately inform the said representative.

III. The lessee shall not deviate substantially from the approved plan of operation until revision or amendments of the plan are approved in writing, or abandon any site, approval for which is required herein, until final cleanup and revegetation, if required, is approved in writing by the authorized officer as provided herein.

IV. Should the lessee believe that compliance with any of the provisions of approval is unnecessary, he may request a waiver thereof by letter to the appropriate authorized officer stating why a waiver should be considered.

E-1

EXHIBIT E

**PLAN OF DEVELOPMENT AND OPERATION
PRUDHOE BAY (PERMO-TRIASSIC) RESERVOIR
PRUDHOE BAY UNIT AGREEMENT
STATE OF ALASKA**

The Plan of Development and Operations ("the Plan") for the Gas Cap and Oil Rim Participating Areas within the Unit has been formulated to achieve maximum economic recovery of oil and gas consistent with good conservation, sound engineering practice and the correlative rights of the Working Interest Owners.

This Exhibit outlines the Plan which the Working Interest Owners have adopted to develop the Unitized Substances of the Initial Participating Areas in as prudent and expeditious a manner as possible. Fundamental to this Plan has been the assessment of reservoir productivity, facility capability, and the time required to finance, design, fabricate, and install the necessary production and transportation facilities.

This Plan summarizes both the short and longer term reservoir management considerations and describes the facilities which will be utilized therein. Detailed technical justification for the Plan is contained in a report entitled "Technical Considerations Prudhoe Bay Unit Operating Plan, North Slope—Alaska." This report was forwarded to the Director, Division of Energy and Minerals Management, Department of Natural Resources, State of Alaska, on October 20, 1976.

Short-Term Plans

The short-term aspects of the Plan cover initial oil and gas off-takes, gas injection, produced water disposal, and development drilling. Early ratification of this Plan is needed to enable Working Interest Owners, and other parties associated with financing and installing production and transportation facilities, to proceed on schedule.

Oil production is anticipated to begin in mid-1977. Production facilities to support an average oil offtake of 1.2 MMB/D will be

completed by January 1978. Well and facility additions are planned during 1978 and 1979 to increase the average oil offtake to 1.5 MMB/D, plus condensate production, when pipeline capacity is available.

Injection facilities will be installed for the re-injection of gas produced in excess of that needed for fuel and sales. Initially this injection capacity will be 1.2 BCF/D but will be increased to approximately 2 BCF/D by mid-1979.

It is planned to commence gas pipeline deliveries of 2 BCF/D as soon as a pipeline and plant to condition the gas to specification can be completed. This is currently estimated to be about five (5) years after the start of oil production. Studies have shown that the Prudhoe Bay (Permo-Triassic) Reservoir could be managed so that the planned deliveries would not affect ultimate oil recovery. Depending upon the reservoir performance, it might be possible to increase gas deliveries to 2.5 BCF/D.

Water production will be minimal initially and will be disposed of by injection into shallower Tertiary Cretaceous sands which are separate from the Permo-Triassic sands. When the produced water becomes significant it will be re-injected into the Sadlerochit formation.

Development drilling to date has been based on two wells per section. Near term plans include drilling selected wells on 160-acre spacing from existing drill sites during 1977.

Initial development within the Prudhoe Bay (Permo-Triassic) Reservoir will be in the Main Area Sadlerochit Formation. Development of the Eileen Area and other Permo-Triassic formations will be phased into the overall Plan so as to maximize the efficiency of the continuing development plan and to maintain field production.

Longer Term Plans

The Working Interest Owners have conducted extensive reservoir performance studies. The results of these studies combined with engineering judgment developed from experience in other fields have led to development of the long-term reservoir management plans.

E-3

In the longer term, the scope of the operation may ultimately include the implementation of a number of measures such as:

- (a) the drilling of wells on one hundred sixty (160) acre spacing, closer if warranted;
- (b) the working over of wells to limit undesirable gas and water production;
- (c) the installation of additional gathering and separation facilities to accommodate rising gas-oil and water-oil ratios, including low pressure systems when necessary;
- (d) the installation of artificial lift in wells;
- (e) the injection of source water where appropriate.

These measures, viewed in conjunction with their possible scale and timing, collectively offer a degree of flexibility which is necessary for the successful management of the energy resources within the Prudhoe Bay (Permo-Triassic) Reservoir.

It is anticipated that with the additional drilling and installation of facilities it will be possible to sustain the planned oil offtakes for approximately eight years before production begins declining. Such development could ultimately require five hundred (500) or more wells on one hundred sixty (160) acre spacing. Further development drilling to less than one hundred sixty (160) acres per well might be justified in selected areas.

It is planned to selectively inject produced water into the Sadlerochit Formation in areas of low natural depletion when volumes become significant. Thus, through redistribution by re-injection, the benefits of natural water influx will be maximized.

It is planned to supplement the injection of produced water with source water injection when predictions of additional recovery can be verified and the economic viability of the project can be substantiated. Reservoir performance and testing are necessary before this project can be engineered to assure successful implementation. Studies by the Working Interest Owners indicate that source water injection is mechanically feasible, but additional studies will be required to optimize the waterflood facility design. Although source water injection plans cannot be finalized, design and implementation

studies will proceed concurrently with field testing and data gathering, so as to reduce the time from final decision to implementation to approximately three years.

Over the life of the Prudhoe Bay (Permo-Triassic) Reservoir the Plan will undergo continued evaluation and modification in the light of observed performance. A very important aspect of this continuous review process will be an active program of reservoir surveillance and testing. Provisions exist within the Plan to monitor intensively gas-oil and water-oil contact movements, reservoir pressures and the performance of individual wells. Preliminary water injectivity tests are also planned to determine injectivity into various subzones of the reservoir and to evaluate water displacement characteristics in the reservoir. The Tertiary/Cretaceous sands overlying the Sadlerochit formation constitute a possible source of test injection water.

Drilling and Facility Plans

The development drilling and production facility plans outlined below are consistent with the objectives of the Plan for the field. The well spacing for this Plan provides flexibility to drill future producing wells and water injection wells as required. Modular construction and the physical layout of the existing production facilities provide maximum flexibility for future additions and expansions.

A multi-rig program will be in operation during 1977 through 1981 and beyond to provide additional wells. The bottom-hole locations of existing development wells and possible locations for future wells on 160-acre spacing are presented in Figure 1. This coverage includes those areas of the Prudhoe Bay (Permo-Triassic) Reservoir with an initial oil column in excess of one hundred (100) ft.

Producing wells are directionally drilled from strategically located drill site pads. These sites consist of gravel pads which insulate the underlying permafrost. Multiple-well drill pads permit concentration of surface facilities reducing required pipeline, road and power distribution networks. Existing drill pads will be extended and future drill pads will be installed as needed to accommodate the development drilling program. The surface locations of existing and possible future drill pads and drill sites are displayed on Figure 1.

Production from the wells in the Main Area will be processed at six field gathering centers flow stations. The first two are scheduled for production start-up during the second quarter of 1977. The third and fourth are scheduled for start-up during the third quarter of 1977. Scheduled start-up of the fifth and sixth will be mid-1978 and mid-1979, respectively. Total field gathering center flow station capacity will be 1.8 MMB/D upon completion of all six facilities. This capacity allows the production offtake requirements for the field to be met with one center station completely shut down.

Initially there will be two flowline configurations which will transport the produced fluids from the wellheads to the field gathering centers flow stations. One configuration incorporates a separate flowline for each well, and the other will consist of common flowlines with well streams commingled at drill site manifolds. Additional flowlines will be needed in the future as development proceeds and additional wells are brought on production. Flowline configuration will depend on operating conditions at the time they are needed. Large diameter flowlines and manifolds are planned to offset the decline of wellhead flowing pressure. With further decline in wellhead flowing pressure, a reduction of first stage separator operating pressure is planned together with a possible expansion and relocation of first stage facilities at the drill pads and drill sites. Concurrently, low pressure compression at the field gathering centers flow stations may also be installed.

At each gathering center flow station the produced fluids will be separated into oil and condensate, gas, and water. Three-stage separation of produced fluids is planned. Well test facilities will be located at the gathering centers or the drillsites, dependent upon flowline configuration. The separator oil and condensate will be processed to pipeline specifications, and shipped through large diameter transit lines to the TAPS origin station. The separator gas will be compressed, conditioned as required, and sent through large diameter transit lines to the central gas compression plant located in the A.R.Co. operating area. Initially, all produced gas, excluding field fuel and fuel for TAPS, will be compressed at the central gas com-

pression plant and reinjected into the gas cap of the Sadlerochit reservoir. Ten (10) wells for initial gas injection purposes have been drilled from a pad just north of the central gas compression plant. If needed, additional gas injection wells will be drilled from a future pad to be located west of the central compression plant.

Some of the gas delivered to the central compression plant will supply the field fuel gas unit. This is located adjacent to the central compression plant and is designed to furnish up to 100 MMCF/D of conditioned gas for use as fuel in field operations and TAPS pump stations.

Future additions to the produced gas system include a plant to condition gas for sales. With the commencement of gas sales, the gas will be routed to the gas conditioning plant for the removal of carbon dioxide and gas liquids for dewpoint control. Tentative plans are to transport some of the gas plant liquids that are extracted to the oil gathering system for delivery to TAPS with the remainder being used for fuel. Processed gas will be returned to the sales boost compression plant for required compression and transport to the sales gas pipeline.

Produced water will be treated, filtered, and injected initially into water disposal wells completed in the shallower Tertiary/Cretaceous sands at locations near the field gathering centers flow stations. Six such wells presently exist at the gathering centers flow stations. Facilities to reinject up to 200 MB/D of produced water will be available and will be augmented as necessary. It is expected that such facilities might be expanded to handle up to 500 MB/D of produced water.

Electrical power for the field is supplied by the central power station located in the BPA operating area. Power generation is by gas turbine. The power is transmitted to the two operating areas by an overhead 69 KV transmission line and supplies the electrical requirements of the various production facilities.

Development of the West End (Eileen Area) of the field is to be phased in later into the overall Plan of Development, consistent with the most efficient production of the field. Additional study of the

E-7

well potentials and better definition of the West End will be required before this further development scheme can be finalized. It is expected that this information will be obtained over the next few years. Nevertheless, a tentative pattern of wells and pads corresponding in scope to the Main Area development has been shown on Figure 1.

Existing and possible future production facilities, pipelines, roads, bridges, airstrips, and base camps needed to support present and future field operations for the Main Area development and for the tentative Eileen Area development are shown on Figure 2.

An annual update of Figure 1 and Figure 2 will be submitted to the Director.

Unit Operators will continue to obtain approvals and permits for Unit Operations as required by State laws, regulations, and/or State Oil and Gas Lease stipulation (Attachment No. 1 hereto).

An annual progress report, summarizing the prior year's activities under this Plan, will be filed with the Director.

Attachment No. 1 to Exhibit E

OIL AND GAS LEASE STIPULATION

I. Prior to commencement of any operations on the lease, the lessee shall obtain written approval from the Director, Division of Lands for the location of all operations and type of facilities in order to protect fish and wildlife, prevent pollution, and minimize surface damage. This stipulation does not affect the requirement that the lessee obtain approval of the Alaska Oil and Gas Conservation Committee pursuant to AS 31 and the regulations adopted thereunder.

The lessee shall:

(a) Submit, in triplicate, at least 30 days prior to beginning any operations on this lease, to the Director, Division of Lands, a plan of operation that will include statements, maps, or drawings relating to:

(1) The methods to be used to assure proper disposal of mud, oily waste, garbage, refuse, and other pollutants.

(2) The design of pollution prevention facilities.

(3) The location of any proposed well or wells, buildings, rights-of-way, airstrips, and storage facilities.

(4) The location and design of material sites.

(5) Measures to be taken to prevent erosion (particularly of roads and material sites) and damage to watersheds and vegetation.

(6) The location of proposed seismic activities.

(b) Keep the operational plan current in all respects.

II. The lessee shall:

(a) Comply with the provisions of the approval and do all things reasonably necessary to prevent or reduce to the fullest extent scarring and erosion of the lands, pollution of the water resources, and damage to the watershed. Should activities of the lessee cause damage to the watershed or pollute the water resource, the lessee agrees to repair such damage in a manner acceptable to the Director.

E-9

(b) Allow authorized personnel of the Department of Natural Resources and the Department of Fish and Game to enter the premises to inspect the installations and operation activities of the lessee.

(c) Prior to the beginning of operations, appoint and maintain, at all times during the term of the lease, a local agent upon whom may be served written orders or notices respecting matters contained in these stipulations and to inform the authorized officer in writing of the name and address of such agent. If a substitute agent is appointed, the lessee shall immediately inform the said representative.

III. The lessee shall not deviate substantially from the approved plan of operation until revision or amendments of the plan are approved in writing, or abandon any site, approval for which is required herein, until final cleanup and revegetation, if required, is approved in writing by the authorized officer as provided herein.

IV. Should the lessee believe that compliance with any of the provisions of approval is unnecessary, he may request a waiver thereof by letter to the appropriate authorized officer stating why a waiver should be considered.

PRUDHOE BAY UNIT
 FIG. 1
 DEVELOPMENT DRILLING PROGRAM

BASED UPON THE 1964 SURVEY OF THE AREA
 BY THE BUREAU OF LAND MANAGEMENT

LEGEND

---	UNIT BOUNDARY
---	BOUNDARY OF COMBINED GAS CAP AND OIL RIM PARTICIPATING AREAS
---	EXISTING WELLS
---	Possible Future Wells
---	EXISTING GAS METERING WELLS

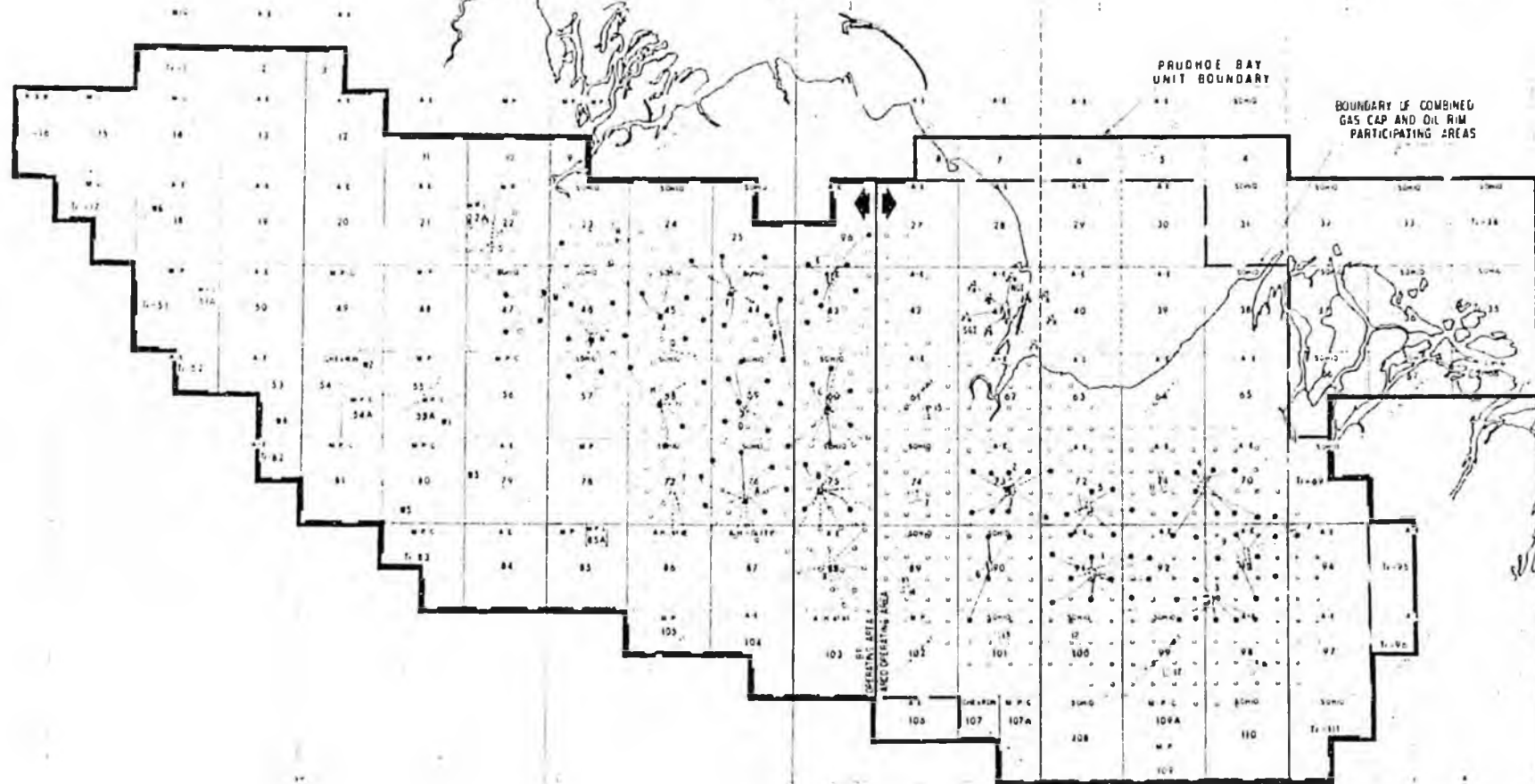
APRIL 1977

PRUDHOE BAY UNIT BOUNDARY

BOUNDARY OF COMBINED GAS CAP AND OIL RIM PARTICIPATING AREAS

WELL PAIRS AND UNITS

- EXISTING
- POSSIBLE FUTURE
- EXISTING GAS METERING WELLS



ARCO Alaska, Inc.
P. O. Box 360
Anchorage, Alaska 99510

Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, Alaska 99502

July 2, 1981

Director
State of Alaska
Division of Minerals & Energy Management
Department of Natural Resources
703 E. Northern Lights Boulevard
Anchorage, Alaska 99503

Subject: Prudhoe Bay Unit
Annual Progress Report

Dear Sir:

In accordance with the requirements of the Prudhoe Bay Unit Agreement, we are submitting an annual progress report of the activities performed under the Plan of Development included as Exhibit 'E'.

If you should have questions regarding this report, please do not hesitate to contact the undersigned.

Sincerely,

P. B. Norgaard

P. B. Norgaard
Vice President
ARCO Alaska, Inc.

P. J. Martin

P. J. Martin
Assistant General Manager
(Operations)
Sohio Alaska Petroleum Company

cc
Attachment

RECEIVED

OCT 28 1981

DIV. OF MINERALS & ENERGY MGMT.
ANCHORAGE, ALASKA

PRUDHOE BAY UNIT
ANNUAL PROGRESS REPORT

In accordance with provisions of the Prudhoe Bay Unit Agreement, this Annual Progress Report has been prepared for submission to the Director, Division of Minerals and Energy Management, Department of Natural Resources. The purpose of this report is to summarize the previous years' activities under the plan of development and operation, which is incorporated in the Unit Agreement as Exhibit 'E'.

Oil Production

Since June 1, 1980, production to the TAPS line has been essentially continuous, at approximately 1.5 MMSTB/D, with one three-week shortfall occurring in late April and early May, 1981. This shortfall was a result of planned maintenance activity at Gathering Center 1. During this period the field rate was maintained at 1.4 MMSTB/D. Otherwise, only brief interruptions to rate occurred during the past year. During the period of June 1, 1980 through May 31, 1981, a total of 551 MMB of oil and condensate was delivered to the pipeline at an average rate of 1509 MBPD. Total net oil and condensate production from the field from April 1, 1977 (the effective date of the Prudhoe Bay Unit) through May 31, 1981 is 1763 MMB, including approximately 3.73 MMB to the crude oil topping plant.

Gas Production And Injection

Since June 1, 1980 through May 31, 1981, a total of 622 MMMSCF of gas has been produced from the field and 571 MMMSCF was reinjected into the

gas cap of the Prudhoe Oil Pool. The majority of the remaining 51 MMMSCF has been used as fuel, purge and pilot gas, with only a minor amount flared. The most significant flaring incident occurred during the Large Diameter Flow Line Test at Flow Station No. 2 in December, 1980, when approximately .22 MMMSCF was flared while testing C Train at low pressure. All flaring is being held to practical minimums and has been in accordance with the rules established by the State of Alaska, Division of Oil and Gas Conservation in Conservation Order No. 145-A of January 12, 1978.

Water Production

Water production during the past year has increased slightly. From June 1, 1980 through May 31, 1981, a total of 14 MMB of water was produced. Approximately 4.6 MMB of this total was produced intentionally from two Drill Site 1 wells in the Eastern Operating Area for produced water injectivity tests at Drill Site 5. The remainder was disposed of by injection into the Cretaceous/Tertiary sands through disposal wells located at each of the Flow Stations/Gathering Centers.

Additional Wells And Facilities

As of June 1, 1980, 244 oil wells were connected and capable of producing to the Flow Stations/Gathering Centers. An additional 40 wells have been added in the Western Operating Area as of May 31, 1981. In the Eastern Operating Area, 27 new wells were added as of May 31, 1981.

The total number of oil producing wells connected and producing on May 31, 1981 was 311. Of these, 160 are in the Eastern Operating Area and 151 in the Western Operating Area. In addition, 53 wells have been drilled and completed but are awaiting perforation. The bottomhole locations of the oil producing wells drilled as of May 31, 1981 are shown in Figure 1, together with possible future 160-acre locations.

During the past year, 4 gas injection wells were perforated at the West Gas Injection Pad, bringing the total number of gas injection wells to 18.

Drilling is currently in progress at Drill Sites 12, 14, 16, and 17 in the Eastern Operating Area. In the Western Operating Area drilling is in progress on Drill Pads A, G, H, M, N, and Y.

Figure 2 shows the location of existing production facilities, pipelines, roads, bridges, airstrips and base camps, together with facilities under construction and possible future facilities.

Continued Development

Well and facility additions are continuing in order to ensure that adequate field capacity is available to meet oil pipeline demand up to a maximum annual average oil rate of 1.5 MMB/D, plus condensate production, in accordance with Conservation Order No. 145. Field facilities will also be available to accommodate gas pipeline deliveries of 2.0 BCF/D when a gas pipeline and plant to condition gas to specification can be completed.

Current plans envision a total of 409 wells in the Eastern Operating Area and 397 wells in the Western Operating Area by the end of 1984.

806

These well count estimates include current and future 160-acre development wells, water injection wells, and wells proposed for drilling on reduced spacing. Continued development drilling will require the expansion of some Drill Sites/Drill Pads as well as the construction of new ones. Facilities to connect these wells and control their production are either being designed or fabricated and will be installed in conjunction with drilling operations. In regard to reduced spacing an application to change Field Rule 2 (well spacing) of Conservation Order 145, Prudhoe Oil Pool, has been filed with the Alaska Oil and Gas Conservation Commission. Upon approval by the Commission, this will allow wells to be spaced closer than 2000 feet.

Gas injection capacity will be increased with the addition of one low-stage compressor at the Central Gas Injection Plant. Scheduled for delivery on the 1981 barge shipment, this will bring the total number of compressors up to 9 low-stage and 4 high-stage units. The addition of 4 gas injection wells at the West Gas Injection Pad during the past year will provide adequate injection well capacity for the scheduled increase in compression capacity. Sufficient injectivity will be available during normal injection well maintenance or stimulation.

Low pressure systems will be installed in annual increments covering several years. The first increment, to be installed at Flow Station 2, is scheduled to be operational in early 1982. Current plans indicate

that by 1984 all three Flow Stations in the Eastern Operating Area will have low pressure capability. In the Western Operating Area, all Gathering Centers will be fully commissioned for low pressure operation by 1984, with the first increment being installed at Gathering Center 2 in 1983.

It is currently expected that gas lift will commence in 1984 at all Flow Stations in the Eastern Operating Area. Gas lift during 1984 will be accomplished with the installation of one compressor at Flow Station 3 with gas lift transmission lines to the other Flow Stations. Plans for expanding gas lift beyond this initial increment are not yet firm. However, studies are continuing in order to determine the optimum timing and operational aspects of future increments. It is currently expected that by 1986 gas lift gas usage will approach 1.2 BCF/D and will be available at all six Gathering Centers/Flow Stations.

An initial increment of produced water injection facilities was installed at Flow Station 2 during the past year. Flow Station 1 already has produced water injection facilities as a result of the Drill Site 5 water injectivity tests. Current plans indicate that additional increments of produced water injection facilities will be added at each Flow Station/Gathering Center through 1986. By the end of 1986, total installed produced water injection capacity, including spares, is expected to be just under 1.6 MMBWD, with about 900 MBWD capacity in the Western Operating Area and about 700 MBWD capacity in the Eastern Operating Area. Ultimate injection of produced water is currently anticipated to be about 1.0 MMBD. Produced water injection into the Sadlerochit

is expected to commence at Field Station 2 when significant quantities of produced water become available. This is currently expected to occur during early 1982.

Major milestones toward startup of a sea water source waterflood have been accomplished during the past year. In early May, 1980, a public hearing was held before the Alaska Oil and Gas Conservation Commission (AOGCC) in which the Unit discussed the plans for implementation of a two million barrel per day source water injection program and a produced water injection program. During the last half of 1980, the Environmental Impact Statement process was completed and on January 2, 1981, the U.S. Army Corps of Engineers issued a permit approving the proposed Beaufort Sea water source plant and associated on-shore facilities. As part of the permit, stipulations for a monitoring program were included. This program would allow evaluation of the effects of the dock extension, water intake, and water treatment plant on the local ecosystem. In March, 1981, an Application for Additional Recovery was approved by the AOGCC. All other major permits are now in-hand. These major permits and approvals by the agencies and the AOGCC have allowed the Operators to proceed toward full scale waterflood startup in 1984 with 2 million barrels per day of installed pump capacity. The design and procurement of materials for this major source waterflood is proceeding on schedule. Source water injection is anticipated to commence about mid-1984 at a rate of between 1.5 and 2.0 MMBD.

Reservoir analysis continues with emphasis on waterflood optimization including pattern selection and water volume distribution. Continuing

produced water injection to drilling in a five-spot pattern at Drill Site 5-11 will give valuable field information regarding expected waterflood performance in terms of water breakthrough timing, produced water volumes, and injectivity. To date, this pattern has performed as expected.

Additional data and understanding has been gained from a Drill Site 5-14 produced water injection test which was run in March and April, 1981. More data will be gathered throughout the field as additional wells are converted to produced water injection.

Reservoir and facilities conceptual design studies are being conducted for development of the Eileen West End area of the field. During the report period, seven wells were drilled in this area of the field to provide better structural definition of this complex, faulted area. Two existing wells, the Kuparuk well, Sec. 22, T11N, R12E, and the ARCO Highland State #1 well, Sec. 24, T11N, R11E, are scheduled for conversion to pressure observation wells. A Sadlerochit production test is being planned for the Kuparuk well prior to conversion. The geologic, fluid pressure and production data is being used to improve the reservoir and facilities studies of the area. These studies are addressing well spacing, waterflooding and optimum facilities development.

ARCO Alaska, Inc.
P. O. Box 360
Anchorage, AK 99510

Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, AK 99502

July 2, 1981

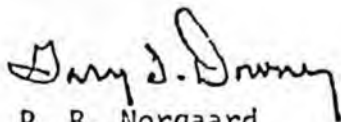
Director
State of Alaska
Division of Minerals & Energy Management
Department of Natural Resources
703 W. Northern Lights Boulevard
Anchorage, Alaska 99502

Subject: EXHIBIT E-1
PLAN OF DEVELOPMENT AND OPERATION FOR
LANDS OUTSIDE THE INITIAL PARTICIPATING
AREAS - PRUDHOE BAY UNIT AGREEMENT
STATE OF ALASKA

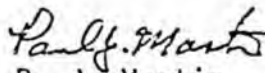
Dear Sir:

Sohio Alaska Petroleum Company and ARCO Alaska, Inc., as Operators of the Prudhoe Bay Unit, respectfully submit herewith a progress report for the twelve (12) months ending June 1980, as required by the final paragraph of Exhibit E-1 to the Prudhoe Bay Unit Agreement.

Sincerely,



P. B. Norgaard
Vice President
ARCO Alaska, Inc.



P. J. Martin
Assistant General Manager
(Operations)
Sohio Alaska Petroleum Company

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Attachment

PLAN OF DEVELOPMENT AND OPERATION FOR LANDS
OUTSIDE THE INITIAL PARTICIPATING AREAS
PROGRESS REPORT - JULY 1, 1980 TO JUNE 20, 1981

Lisburne Reservoir Area

During the report period, the Lisburne limestone formation was penetrated by one well, Sohio's Sag Delta No. 5 on lease No. ADL 34630. The well was located 727' east of west line and 2322' north of south line, Section 36, T12N, R15E, UPM. The well was spudded February 3, 1981 and drilled to a total depth of 11,063' MD and suspended on April 14, 1981. The results are confidential and are on file with the State Oil and Gas Conservation Commission.

Sohio is presently assessing the geological information obtained from Sag Delta No. 5 before deciding on future drilling activity in the area. A small amount of new seismic data was obtained during the past year and evaluation of the Lisburne Reservoir continued to ascertain its development possibilities.

ARCO is currently in the final design stages of the extended production test planned for the West Bay State No. 1 well. Mechanical problems in the well have delayed startup of the test, which is now expected during the fall of 1981. The extended production test will increase understanding of the productivity of the Lisburne reservoir, and provide information for conceptual development studies. Further delineation drilling may be required to better define Lisburne geology.

PRUDHOE BAY UNIT

ANNUAL PROGRESS REPORT

In accordance with provisions of the Prudhoe Bay Unit Agreement, this Annual Progress Report has been prepared for submission to the Director, Division of Minerals & Energy Management, Department of Natural Resources. The purpose of this report is to summarize the previous years' activities under the plan of development and operation, which is incorporated in the Unit Agreement as Exhibit 'E'.

Oil Production

Since July 1, 1979 production to the TAPS line has been essentially continuous, with only very brief interruptions. During the period of July 1, 1979 to May 31, 1980, a total of 484 MMB were delivered to the pipeline at an average rate of 1442 MBPD. Total net oil production from the field from April 1, 1977 (the effective date of the Prudhoe Bay Unit) to May 31, 1980 is 1212 MMB, including approximately 2.45 MMB net to the crude oil topping plant.

Gas Production and Injection

Since July 1, 1979 to May 31, 1980 a total of 480 MMSCF of gas has been produced from the field and 437 MMSCF was reinjected into the gas cap of the Prudhoe Oil Pool. The majority of the remaining 43 MMSCF has been used as fuel, purge and pilot gas, with only a minor amount flared. Flaring has been reduced to practical minimums and has been in accordance with the rules established by the State of Alaska, Division of Oil & Gas Conservation in Conservation Order No. 145-A, of January 12, 1978.

ARCo Alaska, Inc.
P. O. Box 100360
Anchorage, AK 99510

Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, AK 99502

June 29, 1984

Director
State of Alaska
Division of Oil & Gas
Department of Natural Resources
Pouch 7-034
Anchorage, AK 99510

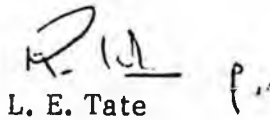
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RE: PRUDHOE BAY UNIT ANNUAL PROGRESS REPORT

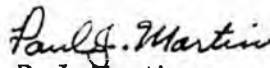
In accordance with the requirements of the Prudhoe Bay Unit Agreement, we are submitting an annual progress report of the activities performed under the Plan of Development included as Exhibit 'E'.

If you should have questions regarding this report, please do not hesitate to contact the undersigned.

Sincerely,



L. E. Tate
Vice President
Engineering and Extension Exploration
ARCo Alaska, Inc.



P. J. Martin
Vice President
Operations and Engineering
Sohio Alaska Petroleum Company

CSF
0537A
Attachment

PRUDHOE BAY UNIT
ANNUAL PROGRESS REPORT

In accordance with the provisions of the Prudhoe Bay Unit Agreement, this Annual Progress Report has been prepared for submission to the Director, Division of Minerals and Energy Management, Department of Natural Resources. The purpose of this report is to summarize the prior year's activities under the Plan of Development and Operation which is incorporated in the Unit Operating Agreement as Exhibit "E".

Oil Production

Since June 1, 1983, production to the TAPS line has essentially been continuous at approximately 1.5 MMBOPD, with only a few brief shortfalls occurring during the last year. These shortfalls, which were primarily associated with routine maintenance activities of the Prudhoe Bay Field or TAPS facilities, were made up for the calendar year 1983 as well as subsequent shortfalls in 1984. During the period June 1, 1983 through May 31, 1984, a total of 559 MMB of oil and condensate was delivered to the TAPS line at an average rate of 1528 MBPD. Total net oil and condensate production from the field from April 1, 1977 (the effective date of the Prudhoe Bay Unit) through May 31, 1984 is 3442 MMB, including approximately 7.8 MMB to the Crude Oil Topping Plant.

Gas Production and Injection

From June 1, 1983 through May 31, 1984, a total of 825 BCF of gas was produced from the field and 753 BCF was injected into the gas cap of the Prudhoe Oil Pool. The majority of the remaining 72 BCF was used as fuel, purge and pilot gas, or injected in connection with

the Flow Station 3 Injection Project (FS-3 IP), with only a minor amount flared. Not included in the above is 120 MMCF flared through May 31, 1984, to allow long-term production testing of West End well 21-11-12 in accordance with State of Alaska, Oil and Gas Conservation Commission Order 145 as amended February 14, 1984.

Water Production

Water production between June 1, 1983 and May 31, 1984, was 28.4 MMBW, an average water cut of 4.8%. Of this total, 6.1 MMBW was produced intentionally from four Drill Site 14 wells in the Eastern Operating Area in order to supply sufficient injection water for the FS-3 IP. Excluding water production from the four source wells, total water increased from the 15.2 MMBW the previous report period to 22.4 MMBW during this reporting period. This increased water production is primarily a result of commissioning low pressure production and gas-lift facilities.

In the Eastern Operating Area (EOA), produced water injection into the Sadlerochit is continuing at Drill Sites 12, 13 and 14 in connection with the FS-3 IP and at Drill Site 4. In the Western Operating Area (WOA), produced water injection into the Sadlerochit is continuing at Well Pad R and is planned to be initiated at Well Pads F and X by year-end.

Field Development

As of May 31, 1984, a total of 598 wells were drilled, completed, and connected for production or injection service to their respective separation center, of which 306 and 292 wells were located in the EOA and WOA, respectively. This represents an increase of 94 wells connected for production or injection service over the past year. An additional 56

wells, 23 in the EOA and 33 in the WOA, have been drilled and completed but are awaiting perforation and/or production facilities. The bottom-hole locations of the 654 production and injection wells drilled as of May 31, 1984 are shown on Figure 1. Of the total, 483 wells are 160-acre locations and 171 wells are 80-acre locations. As of May 31, 1984, drilling was in progress at Drill Sites 3 and 12 in the EOA and at Well Pads S and X in the WOA.

Current plans envision an estimated 880 to 950 wells will be drilled in the main area of the field. Of these, 459 to 499 are in the EOA and 421 to 451 are in the WOA. These well count estimates include 160-acre development wells, 80-acre infill wells, water injection wells, and wells associated with the FS-3 IP. Current projections indicate that most of the wells will be drilled by 1988. Continued development drilling will require primarily the expansion of existing drill sites and well pads in addition to the possible construction of one new drill site. Facilities to tie-in these wells are either being designed or fabricated and will be installed coincidental with drilling operations. Following the 1984 Sealift, facilities will be available to accommodate approximately 772 wells.

Figure 2 shows the location of existing production facilities, pipelines, roads, bridges, airstrips and base camps, together with facilities under construction and possible future facilities.

Well and facility additions are continuing in order to ensure that adequate field capacity is available to meet oil pipeline demand up to a maximum annual average oil rate of 1.5 MMBOPD, plus condensate production, in accordance with Conservation Order No. 145. Based on five year planning studies, the Unit expects to maintain this average oil

production rate through 1986. These same studies also indicate that in 1987 the Unit will not be able to maintain this annual average oil rate due primarily to the expanding gas cap combined with finite field gas handling capacity. Field facilities are expected to be available to accommodate gas sales of approximately 2.0 BCFD when gas transportation facilities become available.

All planned low pressure compression facilities for the six separation centers have been sealifted, and by year-end 1984 all will be operational. Gathering Centers 1 and 3 are currently being readied for the start of the low pressure operation while Gathering Center 2 and Flow Stations 1, 2 and 3 systems are operational. Additional gas dehydration capacity is planned for each of the gathering centers in the WOA in the 1987 time frame. Based on current plans, 29 of the 34 producing drill sites and well pads will have low pressure capability by year-end 1984.

The first major increment of the gas-lift system was sealifted in 1983, and is operational at Flow Station 3. Including the smaller gas-lift packages provided in late-1982 for Well Pad X and the FS-3 IP, the nominal compression capacity currently available is 470 MMCFD. The final gas-lift compressor increment, under construction in the Lower 48, is planned to be operational at Gathering Center 1 by mid-1986, and will increase the field-wide capacity to a nominal 1370 MMCFD. The gas-lift transmission line between separation centers is operational and, in effect, provides a header arrangement extending from Gathering Center 2 on the extreme western end of the field to Flow Station 2 on the extreme eastern end. Gas-lift gas discharged from the existing and future compressors can be routed to any of the six separation centers. Ultimate gas-lift usage in the main field currently is projected to be in the 1.3-1.4 BCFD range, but continued studies are

planned based upon system and field performance in the coming years. While recognizing that gas-lift will be provided to wells on a priority and as-needed basis, current plans are that 12 drill sites/well pads in or adjacent to the waterflood areas will have access to gas-lift by year-end 1984. They are Drill Sites 6, 12, 13, 14, 16 and 17 in the EOA, and Well Pads H, M, R, S, X and Y in the WOA. The remaining drill sites/well pads at which gas-lift ultimately is deemed necessary should be tied-in by late 1988.

The Central Compressor Plant (CCP) used to inject produced gas into the gas cap is equipped with nine low-stage and four high-stage turbine-driven compressors. The number of injection wells remains unchanged at 18, with 14 located at the North Injection Pad and four located at the West Injection Pad. Although a miscible gas injection project planned for startup in 1987 (discussed later in the report) will enable increased field gas production rates, additional CCP turbine-driven compressors and injection wells will not be required. However, modifications to the low-stage compressors are planned in order to efficiently handle the lower molecular weight residue gas from the NGL/EOR Plant. Two turbine-driven boost compressors are planned for installation at the inlet of the NGL/EOR Plant.

Produced water injection facilities are in service at five of the six separation centers with only those at Gathering Center 1 remaining to become operational. By year-end 1984, the total available injection capacity will be a nominal 1185 MBWPD with 785 MBWPD being in the WOA and 400 MBWPD being in the EOA. Additional injection capacity under consideration would increase the ultimate to a total of 730 MBWPD in the EOA. While recognizing that the injection capacity available at each of the six separation centers is independent of the others, the total produced water is projected to reach about 1100 MBWPD in the 1988-1989 time frame.

The Prudhoe Bay Unit source waterflood project started up on June 14 with water injection at Drill Site 9, and a step-wise increase in injection rate is underway. Total water injection rates, including produced water, are projected to reach 900-1050 MBWPD by year-end 1984. Combined source and produced water injection rates may reach 2.2 MMBWPD by 1988 based on current predictions. A reservoir surveillance program was submitted to the Alaska Oil and Gas Conservation Commission in accordance with the Unit's application for additional recovery by waterflood in December, 1980.

During the past year, the injection pattern has been selected for the western Peripheral Wedge Zone (PWZ) and the previously selected Northwest Fault Block (NWFB) pattern has been modified. The Flow Station 2 and eastern PWZ long-term injection patterns remain unchanged. In the NWFB, an 80-acre per well inverted nine-spot waterflood pattern will be utilized to better accommodate future miscible gas injection. Waterflooding in the Peripheral Wedge Zone will be based on a similar development, with the exception of the H and U-Pad area where the narrow target favors a line-drive approach.

Reservoir and facilities conceptual design studies for development of the Eileen-West End area of the field have continued during the past year. Information being obtained from evaluation of the long-term test of well 21-11-12 will be key to defining the ultimate development of the West End area. An interpretation of 650 miles of 3-D seismic surveys taken early this year will provide further definition of the structural configuration and ultimate potential in the coming year. Continuing reservoir studies, now incorporating the above information, will be used to determine an optimum depletion strategy. Likewise, continuing facility studies will define development options.

Design engineering is underway toward the implementation of a large scale enhanced oil recovery project, the Prudhoe Bay Miscible Gas Project (PBMGP), to start up as early as 1987. PBMGP facilities will consist of an NGL/EOR Plant providing TAPS transportable NGLs and miscible injectant, as well as injectant compression, distribution, and well site injection facilities. Engineering design studies are currently underway, and are aimed toward a 1986 Sealift. The Project is expected to affect about 10% of the Sadlerochit reservoir and will be applied in areas already under waterflood at that time. At startup, water alternating miscible gas (WAG) injection is planned to begin in 42 patterns utilizing then existing water injectors. Activities aimed at optimizing EOR performance will continue through analysis of FS-3 IP and waterflood response and additional studies. The PBMGP was certified by the Alaska Oil and Gas Conservation Commission as a qualified tertiary recovery project on March 5, 1984.

Miscible gas injection in the FS-3 IP resumed on April 22, 1984, after interruption by an explosion and fire on May 26, 1983. While the rebuild effort resulted in minor system changes, facility capacity remains essentially unchanged at approximately 49 MMCFD of miscible injection. During the interruption of miscible gas injection, water injection and production activities were managed to maintain a proper reservoir pressure level. All 60 wells related to the Project have been drilled and perforated. Miscible gas injection currently averages about 43 MMCFD with water injection averaging about 74 MBWPD. Repeat logging of observation well 13-98 continues to provide valuable insight regarding water movement in the Sadlerochit. Current plans are to continue operating the FS-3 IP independently of the Prudhoe Bay Miscible Gas Project scheduled for startup in 1987 although facilities to link the two projects are planned.

ARCo Alaska, Inc.
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Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, AK 99502

June 29, 1984

Director
State of Alaska
Division of Oil & Gas
Department of Natural Resources
Pouch 7-034
Anchorage, AK 99510

file, 3 pm

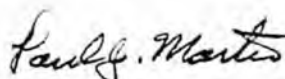
RE: EXHIBIT E-1
PLAN OF DEVELOPMENT AND OPERATION FOR
LANDS OUTSIDE THE INITIAL PARTICIPATING
AREAS - PRUDHOE BAY UNIT AGREEMENT
STATE OF ALASKA

Sohio Alaska Petroleum Company and ARCo Alaska, Inc., as Operators of the Prudhoe Bay Unit, respectfully submit herewith a progress report for the twelve (12) months ending June 1984, as required by the final paragraph of the Exhibit E-1 to the Prudhoe Bay Unit Agreement.

Sincerely,



L. E. Tate
Vice President
Engineering and Extension Exploration
ARCo Alaska, Inc.



P. J. Martin
Vice President
Operations and Engineering
Sohio Alaska Petroleum Company

CSR
0531A
Attachment

PLAN OF DEVELOPMENT AND OPERATION FOR LANDS
OUTSIDE THE INITIAL PARTICIPATING AREAS
PROGRESS REPORT: JULY 1, 1983 TO JULY 1, 1984

LISBURNE RESERVOIR

Considerable progress was made in the past year in further delineating the Lisburne Reservoir. It is anticipated that a Participating Area for the Lisburne will be established sometime from mid-1985 to late 1986 in accordance with Article 5.3 of the Prudhoe Bay Unit Agreement.

During the report period, four delineation wells have been completed by the Owners in the Lisburne Development.

<u>Owner</u>	<u>Well Name</u>	<u>Bottom Hole Location</u>
ARCo/Exxon	South Point State #1	18-11-15
ARCo/Exxon	Pingut State #1	24-11-15
ARCo/Exxon	South Bay State #1	22-11-15
Sohio	Sag Delta #6	2-11-15

These wells were extensively cored, logged and drill stem tested in order to evaluate the Lisburne continuity, reserves, and productivity. A two-month production test has been completed on each of the three ARCo/Exxon wells, and a similar test is underway on the Sohio well. Extensive geological, geophysical and reservoir engineering studies are ongoing in order to evaluate and optimize reservoir development of the Lisburne. The data obtained from the above four delineation wells plus previous drilling provides the basis for these studies. It currently appears that the Lisburne Development is contained entirely within the Prudhoe Bay Unit. A development decision is expected during the third quarter 1984.

Conceptual and preliminary facility designs have been completed and final engineering was initiated in January, 1984. Drill site modules are planned to be fabricated and realifted in 1985 with sealift of production center facility modules planned for 1986. The Lisburne Production Center (LPC), to be commissioned by early 1987, will be located south of Drill Site 18 and will be designed to process a nominal 100 MBOPD and 400 MMCFD of gas with later expansion to 600 MMCFD, if necessary.

The crude oil stream from the drill sites will be routed through a trunk and lateral gathering system to the LPC. The produced gas will be stripped of NGLs prior to injection into the Lisburne reservoir. The NGLs will be blended with the processed crude oil up to allowable TAPS vapor pressure specifications. The commingled stream will then be transported from the LPC, by a separate pipeline, directly to Pump Station 1. The LPC, which is designed to be self-sufficient, will include separation trains, NGL recovery trains, power generation facilities, and compressors for gas injection.

The Lisburne wells will be directionally drilled from centralized gravel pads. Development plans call for seven drill sites, one of which will be an island in Prudhoe Bay that will be accessible by a causeway. It is anticipated that up to 200 producing wells will be drilled on 160-acre spacing with eight to twelve gas injection wells, and one water disposal well. Drilling is expected to begin in the second half of 1984 and the program may include up to four rigs by 1986.

Major permit applications including gravel, NPDES, and PSD permits have been submitted. Several agencies have indicated concern over a gravel causeway and discussions are underway to resolve this issue. The Lisburne Owners also plan to seek field rules approval from the AOGCC during 1984.

KUPARUK RESERVOIR

During the report period, the Kuparuk interval was penetrated by two Prudhoe Bay Unit Sadlerochit development wells drilled from the S-Pad located in Sec. 35, T12N, R12E.

The results of these wells are on file with the State.

<u>Well</u>	<u>BHL</u>	<u>Spud Date</u>	<u>Completion Date</u>	<u>Total Depth (MD)</u>	<u>Lease ADL #</u>
S-4	34-12-12	7-19-83	8-9-83	9575'	28258
S-5	35-12-12	6-28-83	7-19-83	10810'	28257

The S-4 well was logged through the Kuparuk interval and 116 feet of core was acquired in the Kuparuk. Another S-Pad well is to be logged, conventionally cored, and extensively side-wall sampled later this year. These data together with additional seismic data and potential further delineation drilling information will be incorporated into an ongoing study to determine the development potential of the Kuparuk reservoir within the Unit area.

ENDICOTT

As noted in last year's report, it appears that the Endicott Reservoir underlies leases in the northeast corner of the Prudhoe Bay Unit, the adjacent Duck Island Unit, as well as State leases that are not currently included in any Unit. As a consequence, many Endicott activities are being undertaken cooperatively by the Endicott group of leaseholders (Sohio Alaska Petroleum Company, ARCo Alaska, Inc., Exxon Corporation, Union Oil Company of California, Amoco Production Company, Cook Inlet Region, Inc., NANA Regional Corporation Inc., and Doyon Ltd.). The Director has been kept advised of Endicott activities in various contacts with the Endicott leaseholders.

The Endicott Project progressed from the conceptual engineering phase to the preliminary engineering phase in mid-1983. The reservoir description of the field was updated and reservoir models to simulate various reservoir management strategies were developed. Unitization efforts are ongoing.

Summary of Work Progress

Work planned for the 1983-1984 period was essentially completed and goals were met. Details of the work performed in 1983-1984 are summarized below.

Work Conducted Since Previous Report

(i) Geophysical

The 3-D seismic data obtained in early 1983 has been processed.

(ii) Engineering Studies

The Endicott leaseholders contracted Ralph M. Parsons to perform preliminary engineering studies of such items as the islands, causeway, access road, and facilities. Santa Fe Braun was contracted to perform preliminary engineering studies for the drilling facilities and all the pipeline related work. All of the preliminary engineering studies have been completed, and a definitive cost estimate for the project is being prepared at this time. Additional work and studies performed include:

- Hydrology Study
- Ice Force Study
- Gravel Source Study
- Water Compatibility Tests
- Crude Gel Tests
- Crude Dehydration Tests
- Coastal Engineering Study
- Pipeline Thermal Modeling
- Winter Geotechnical Study
- 3-D Hydraulic Model Study
- Wellbore Thermal Modeling

At this time, the project design includes:

- One Main Production Island with drilling, well testing, and processing facilities for a nominal 100 MBOPD and 200 MMCFD of produced gas, and an NGL extraction plant.

- One Satellite Drilling Island with drilling and well testing facilities.
- A gravel causeway connecting the islands and the islands to the shore.
- A Waterflood Intake Structure located on the north side of the Main Production Island.
- Main Construction Camp and Base Operations Camp located on the Main Production Island.
- Tie-in capability for a maximum of 120 wells.

(iii) Environmental/Permits

Environmental Research Technology (ERT) was contracted to prepare the Environmental Impact Statement (EIS) for the Endicott Project. A Draft EIS was issued in January 1984. Public hearings were held on March 1st and March 5th in Barrow and Anchorage, respectively. Public and Agency comments were handled by the Corps of Engineers and ERT with Endicott leaseholder assistance. A Preliminary Final EIS was then issued in the second quarter of 1984 for comment. The basic concern of the Agencies was the use of a solid fill causeway. The Endicott leaseholders are prepared to construct a breach in the causeway and are discussing the size, location and design of the breach with State, Federal and Borough Agencies. Numerous permit filings including NPDES and PSD permits have been made in support of the project. The Endicott leaseholders have also conducted discussions with the AOGCC directed towards a public field rules hearing.

(iv) Unitization

The Endicott leaseholders continue working to finalize unitization. The expected plan of unitization will be to delete leases ADL 34633, 34634 and 34636 from the Prudhoe Bay Unit, and at the same time expand the Duck Island Unit to

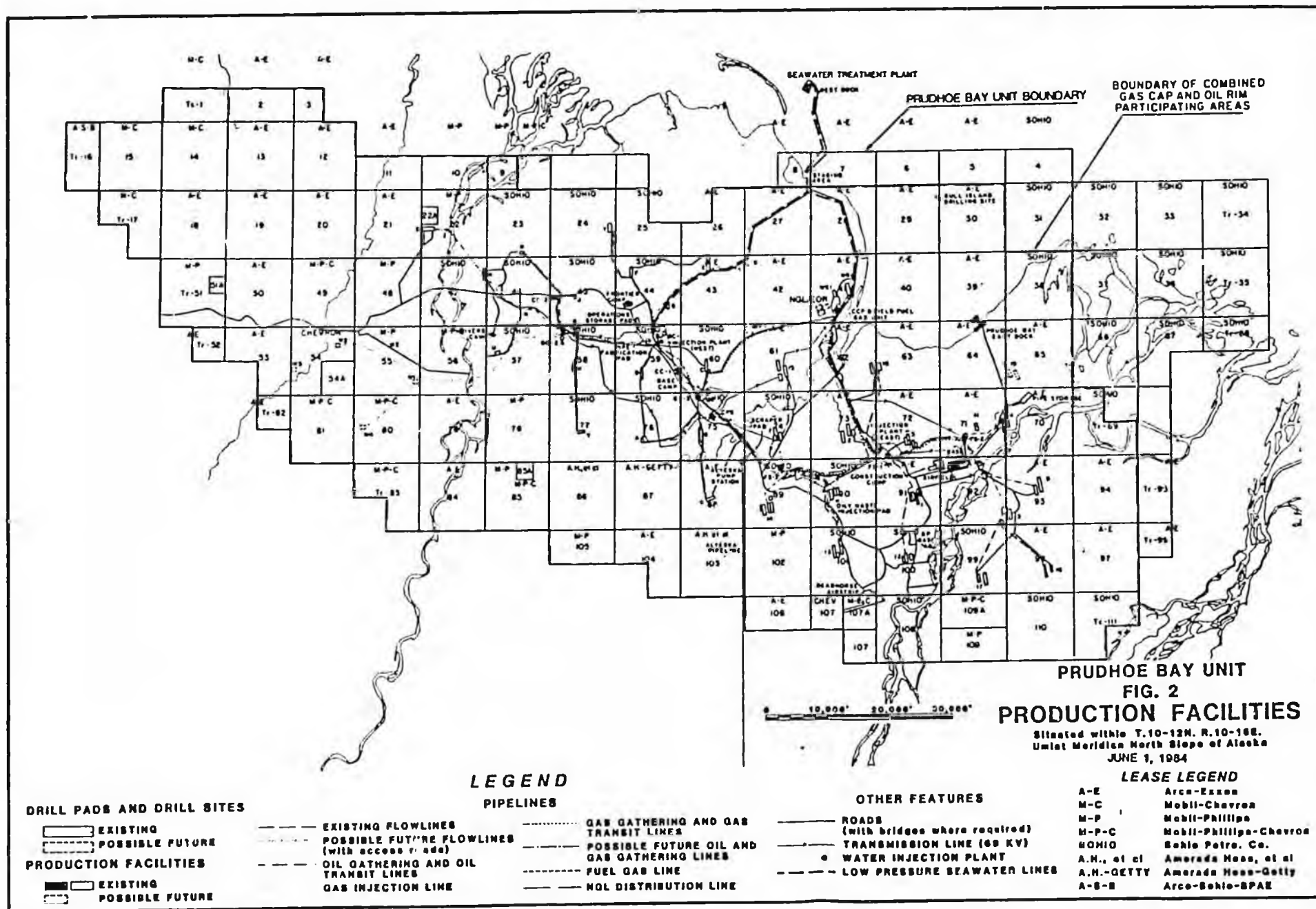
include those leases listed above as well as adding leases ADL 312828 and 312834. The Endicott leaseholders are working with the Division of Oil and Gas, Department of Natural Resources, to secure necessary State approvals.

Work in Progress

The major objective continues to be to work towards a development decision by year-end 1984 to preserve an option for a 1988 field startup. A detailed cost estimate has been issued and engineering studies to assist in optimization of the project will continue. Detailed engineering will commence in the third quarter of 1984 and continue through 1985. If the project goes forward, gravel placement for the haul road and causeway will begin in late 1984 or early 1985. The Final Environmental Impact Statement (FEIS) should be issued in mid-1984. Permit applications will be pursued.

NORTH PRUDHOE BAY (PERMO-TRIASSIC)

During the report period there were no wells drilled nor was there any seismic data acquired in the North Prudhoe Bay area.



PRUDHOE BAY UNIT - LISBURNE DEVELOPMENT

Project Description. Consistent with the Prudhoe Bay Unit Operating Agreement, ARCO Alaska, Inc., as Operator, has completed a delineation tract well and production testing program that has proven the commerciality of the Lisburne Reservoir. Pursuant to the Unit Agreement, a separate Participating Area will be created within the Prudhoe Bay Unit for the Lisburne horizon. The oil from the estimated 3 billion barrel reservoir will be initially processed at a nominal rate of 100,000 barrels of oil per day and 400 million cubic feet of gas per day. Optimum production startup is targeted for late 1986/early 1987 (prior to anticipated Prudhoe Bay Unit Permo-Triassic production decline). The areal extent of the identified Lisburne Reservoir encompasses onshore and offshore State 1/8 royalty leases. Approximately 25-30% of the Lisburne production will be recovered from the proposed offshore facility. The offshore drill site/injection site is located above the largest known gas cap in North America. Onshore facilities include 5 new drill sites (all partially built), connecting pipeline corridors, and a Lisburne Production Center. The locations of the project and facilities are integrated into and share as much existing Prudhoe Bay Unit facilities as possible.

Permit Status. State, Federal and local government permit applications were filed May 4, 1984. The filings culminate one year plus of ARCO/Agency coordination which has produced several documents detailed below. Studies to date identify Prudhoe Bay as an open water shoal protected (2' water depth at shoal) coastal area which, for the most part, freezes to the bottom in winter. Oceanographic impacts appear limited to the Bay, since the proposed causeway aligns with predominant winds and currents. Nevertheless, common concerns for Beaufort Sea causeways continue to be voiced. Subsea pipeline (\$30-50 million incremental) and elevated pile support (\$250 million incremental) designs have been discussed. Breaches 100' to 1300' in width (\$20-40 million incremental) have also been addressed, even though the studies do not justify a breach. Unnecessary and unjustified offshore mitigative burdens will push the offshore project costs past the feasible and prudent pivot point, thereby, favoring an onshore contingency development plan resulting in lost offshore recoverable reserves. As always, ARCO has mitigated many of the onshore concerns over the past year through State, Federal and local government coordination meetings and through use of the Lisburne study documents. Additional onshore mitigation representing \$30 million worth of incremental costs has been formally requested by one commenting agency. Further onshore mitigation will be considered as it conforms to current Prudhoe Bay Unit operating practices and sound field development principles.

Project Documents.

1. Lisburne Development Area 1983 Environmental Studies, 12/15/83 (Agency designed).
2. Lisburne Project Environmental Impact Assessment, 2/6/84.
3. PBU Lisburne Development Facilities Justification and Alternatives Paper, 4/10/84.
4. Lisburne Development Drainage and Erosion Control Design and Criteria Manual, May 1984.
5. U. S. Army Corps of Engineers, Lisburne Project Environmental Assessment, May, 1984.

PRUDHOE BAY UNIT - LISBURNE
DEVELOPMENT

Executive Summary

Project Components: Six drill sites [one offshore drill site/injection site, five onshore drill sites (all partially built)], connecting pipelines, gravel causeway (possible breach), one onshore gas injection site, Lisburne Production Center, Put River pipeline crossing.

Construction Schedule: 1984 Onshore-drill site expansions, pipeline/construction pads, Lisburne Production Center, onshore gas injection pad.

1985 Put River Crossing, offshore drill site/injection site and causeway to +4' above water elevation, Sealift (drill site buildings and heaters).

1986 Offshore drill site/injection site and causeway to +15' above water elevation, Sealift (Lisburne Production Center Modules)

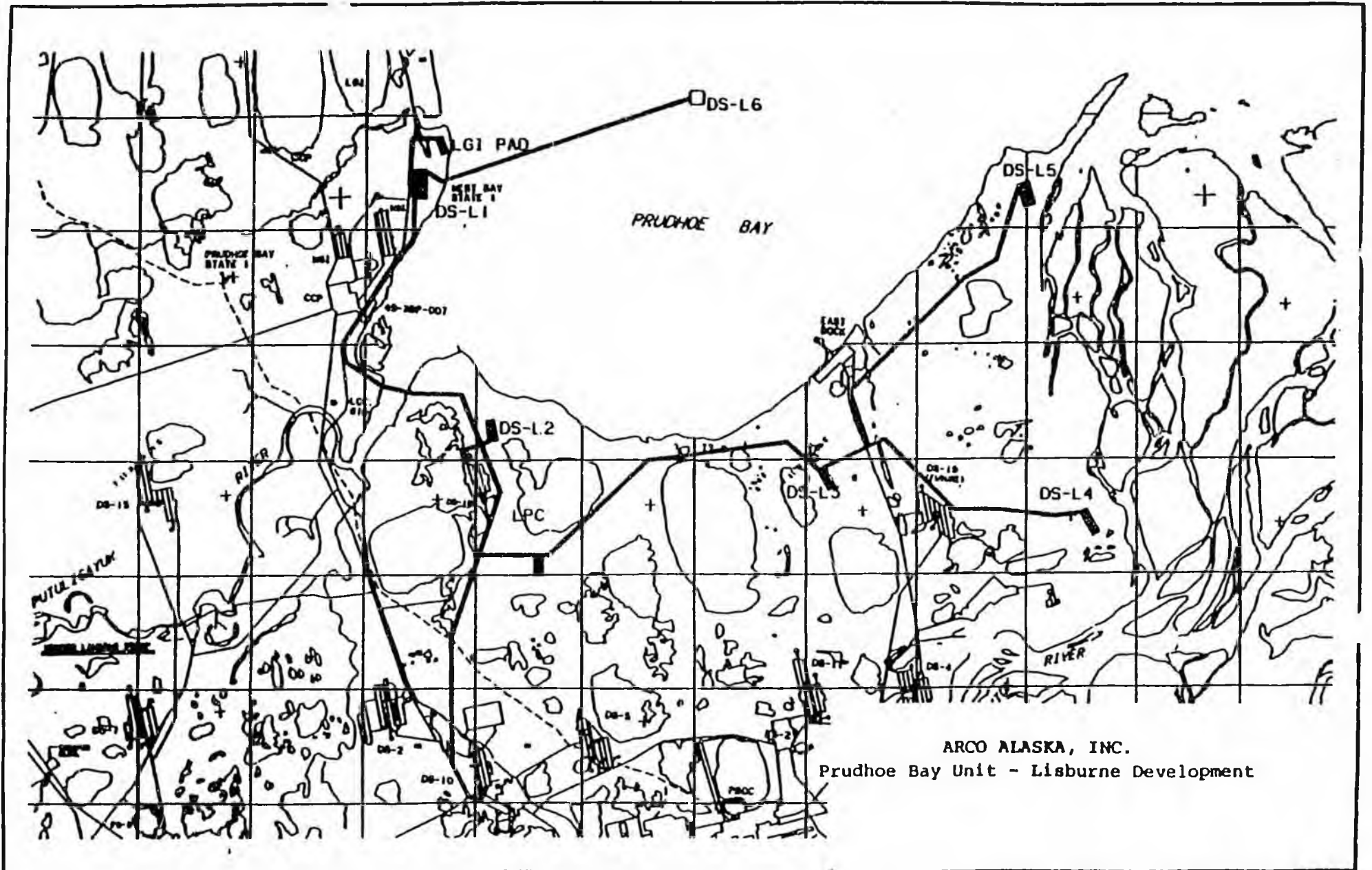
1986-87 Lisburne Startup

Controversial Aspects:

1. Gravel causeway (breach or no breach, if breach, what size?)
2. Pipeline construction pads
3. Pipeline corridor and crossing over Put River

Project Alternatives:

<u>Alternatives</u>	<u>Incremental Costs</u>
1. Subsea Buried Pipeline	\$30-50 million
2. Elevated Pile Supported Causeway/Pipeline	\$250 million
3. Breached Causeway	
a. 100'	\$20 million
b. 600'	\$30 million
c. 1300'	\$40 million
4. Follow Existing Pipeline Corridors (Along East Dock Road to PBOC to West Dock Road to Drill Site 18)	\$20 million
5. Follow <u>Existing</u> Put River Crossing	\$8-10 million



ARCO ALASKA, INC.
Prudhoe Bay Unit - Lisburne Development

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June 29, 1983

RECEIVED

JUN 30 1983

DIV. OF MINERALS & ENERGY MGMT.
ANCHORAGE, ALASKA

Director
State of Alaska
Division of Minerals & Energy Management
Department of Natural Resources
555 Cordova
Anchorage, AK 99501

EXH E

1st update to 5 year POD

RE: PRUDHOE BAY UNIT ANNUAL PROGRESS REPORT

In accordance with the requirements of the Prudhoe Bay Unit Agreement, we are submitting an annual progress report of the activities performed under the Plan of Development included as Exhibit 'E'.

If you should have questions regarding this report, please do not hesitate to contact the undersigned.

Sincerely,

Leland E Tate

L. E. Tate
Vice President
Engineering and Extension
Exploration
ARCO Alaska, Inc.

Paul J. Martin

P. J. Martin
Vice President
Operations and Engineering
Sohio Alaska Petroleum Company

csr
Attachments

PRUDHOE BAY UNIT

ANNUAL PROGRESS REPORT

In accordance with the provisions of the Prudhoe Bay Unit Agreement, this Annual Progress Report has been prepared for submission to the Director, Division of Minerals and Energy Management, Department of Natural Resources. The purpose of this report is to summarize the prior year's activities under the Plan of Development and Operation which is incorporated in the Unit Agreement as Exhibit "E".

Oil Production

Since June 1, 1982, production to the TAPS line has been essentially continuous at approximately 1.5 MMSTB/D, with only a few brief shortfalls occurring during the last year. These shortfalls were primarily associated with normally planned maintenance activities of the Prudhoe Bay Field or TAPS facilities. During the period June 1, 1982 through May 31, 1983, a total of 558 MMB of oil and condensate was delivered to the TAPS line at an average rate of 1528 MSTB/D. Total net oil and condensate production from the field from April 1, 1977 (the effective date of the Prudhoe Bay Unit) through May 31, 1983 is 2883 MMB, including approximately 6.53 MMB to the crude oil topping plant.

Gas Production and Injection

From June 1, 1982 through May 31, 1983, a total of 797 BSCF of gas was produced from the field and 732 BSCF was reinjected into the gas cap of the Prudhoe Oil Pool. The majority of the remaining 65 BSCF was injected in the Flow Station 3 Injection Project or used as fuel, purge and pilot gas, with only a minor amount flared. All flaring is being held to practical minimums and has been in accordance with the rules established by the State of Alaska, Division of Oil and Gas Conservation in Conservation Order No. 145-A of January 12, 1978.

Water Production

Water production between June 1, 1982 and May 31, 1983, totalled 20.3 MMB. Of this total, 5.1 MMB was produced intentionally from four Drill Site 14 wells in the Eastern Operating Area in order to supply sufficient water for the Flow Station 3 Injection Project (enhanced oil recovery project utilizing miscible gas displacement). Excluding water production from the four source water wells, total water increased slightly from 12.6 MMB the previous year to 15.2 MMB the past year. In the Eastern Operating Area, produced water injection into the Sadlerochit has been initiated at Drill Sites 13 and 14 in connection with the Flow Station 3 Injection Project and at Drill Site 4 at Flow Station 2. Routine injection into the Sadlerochit in the DS 5-17 well is continuing but will be replaced as injection is initiated in the Drill Site 12 area later this year. In the Western Operating Area, produced water injection into the Sadlerochit has been recently initiated at Well Pad R at Gathering Center 2. Produced water injection into the Sadlerochit will occur in late 1983 at X-Pad at GC-3. GC-1 will continue injection into the Cretaceous/Tertiary sands until mid-1984, at which time Sadlerochit injection facilities will become available.

Additional Wells and Facilities

As of May 31, 1983, a total of 504 wells were drilled, completed, and connected for production or injection service to their respective Flow Stations/Gathering Centers, of which 265 and 239 wells were located in the Eastern and Western Operating Areas, respectively. An additional 105 wells, 31 in the East and 74 in the West, have been drilled and completed but are awaiting perforation and/or production facilities. The bottom-hole locations of the oil producing wells drilled as of May 31, 1983 are shown in Figure 1. Of the total 609 wells drilled as of May 31, 1983, 468 are 160-acre locations and 141 are 80-acre locations.

As of May 31, 1983 drilling was in progress at Drill Sites 13 and 14 in the Eastern Operating Area. In the Western Operating Area, drilling was in progress at Well Pads J and M.

Current plans envision an estimated 915 to 984 development wells for the main area of the field, or 478 to 516 wells in the Eastern Operating Area and 437 to 468 wells in the Western Operating Area. These well count estimates include current and future 160-acre development wells, 80-acre infill wells, and water injection wells. Current projections of drilling activity levels indicate that most of the wells will be drilled by 1987. Continued development drilling will require the expansion of some drill sites/well pads as well as the construction of new ones. Facilities to tie-in these wells are either being designed or fabricated and will be installed coincidental with drilling operations. For example, following the 1983 sealift, facilities will exist to accommodate approximately 710 wells; following the 1985 sealift, current planning envisions up to approximately 845 wells can be accommodated.

*all - 100% the oil
to be drilled.*

Figure 2 shows the location of existing production facilities, pipelines, roads, bridges, airstrips and base camps, together with facilities under construction and possible future facilities.

Well and facility additions are continuing in order to ensure that adequate field capacity is available to meet oil pipeline demand up to a maximum annual average oil rate of 1.5 MMSTB/D, plus condensate production, in accordance with Conservation Order No. 145. Field facilities are also expected to be available to accommodate gas pipeline deliveries of approximately 2.0 BSCFD when a gas conditioning plant and pipeline are completed.

Low pressure systems will be installed at each of the Flow Stations/Gathering Centers in annual increments over several years. In the Eastern Operating Area, low pressure systems at Flow Stations 2 and 3 were commissioned in the last half of 1982, and current plans indicate that Flow Station 1 will have low pressure capability by early 1984. In the Western Operating Area, all Gathering Centers will have low pressure capability by mid-1984 with the first increment planned for startup at Gathering Center 2 later this year. Based on current plans, approximately 27 producing drill sites/well pads will have low pressure capability by late-1984 with the remainder by late 1987.

Gas lift was initiated in late-1982 with the commissioning of a nominal 30 MMSCFD capacity compressor at Gathering Center 3 for X-Pad usage in the Western Operating Area. An additional 45 MMSCFD of gas-lift capability was also commissioned in late 1982 at Flow Station 3 in the Eastern Operating Area in connection with the Flow Station 3 Injection Project. Approximately two-thirds of the Flow Station 3 gas-lift capacity is currently being utilized to produce source water wells for the Injection Project with the remaining capacity available for oil production at Drill sites 13 and 14. In early 1984, the gas-lift system will be expanded to other areas with the installation of a nominal 375 MMSCFD capacity compressor at Flow Station 3, gas-lift transmission lines between Gathering Centers and Flow Stations, and a tie line connecting the two sides of the field. Currently, it is anticipated that other large gas-lift increments will be commissioned in 1986 and 1987. Current predictions envision gas-lift usage in the main field area to be 1.3 to 1.4 BSCFD by 1987; however, further study and field performance is required to better define the timing of future increments and the ultimate gas-lift system requirements. Gas lift will be provided to drill sites/well pads on a priority basis. Based on the current plan, approximately 13 producing drill sites/well pads will have gas-lift capability by late 1984, with the remaining equipped by late 1988.

The Central Gas Injection Plant is currently equipped with nine low-stage and four high-stage compressor units. Eighteen gas injection wells are currently available, including fourteen at the North Injection Pad and four at the West Injection Pad. Adequate gas injection well capacity is available to accommodate the capacity of the Injection Plant during normal well maintenance and/or stimulation downtime.

Produced water injection facilities have been installed at the three Flow Stations in the Eastern Operating Area, and at Gathering Centers 2 and 3 in the Western Operating Area. Facilities for Gathering Center 1 will be sealifted this year and are expected to be operational by mid-1984. By the end of 1987, total installed injection capacity is expected to be approximately 1.7 MMBWPD, with about 900 MBWPD capacity in the Western Operating Area and 800 MBWPD capacity in the Eastern Operating Area. Ultimate injection of produced water is currently projected to be about 1.3 MMBWPD.

The Prudhoe Bay Unit source waterflood project remains on schedule for the planned mid-1984 startup of source water injection. Initial rates including produced water are projected to be in the range of 1.4-1.5 MMBWPD in 1984. The basic waterflood plans and implementation schedule presented in the May 1980 Prudhoe Oil Pool Rules Hearing and the December 1980 Secondary Recovery Permit Application are unchanged at this time. Fabrication of the Seawater Treating Plant and East and West side injection facilities are on schedule and will arrive on the North Slope in the 1983 Sealift. The 1982 environmental monitoring program results have been provided to the Corps of Engineers, and planning for the 1983 program is nearing completion. Additionally, development of a comprehensive reservoir surveillance program is underway in conjunction with detailed waterflood implementation planning.

Injection patterns have been selected for the major waterflood areas which are scheduled for startup in mid-1984. These areas are the Northwest Fault Block, Flow Station 2 and the eastern Peripheral Wedge Zone. An injection pattern for the western portion of the Peripheral Wedge Zone will be selected by year-end 1983 with waterflood startup planned for 1985. An 80-acre peripheral waterflood pattern is currently planned for the Northwest Fault Block. Based on waterflood performance, a row of centerline injectors along the central fault block may be added at a later date to enhance recovery. In the Flow Station 2 area, combination 320-acre inverted nine-spot/five-spot patterns will be implemented with the five-spot patterns used primarily in the updip and downdip areas. As infill development drilling proceeds, the five-spot patterns may evolve into inverted nine-spot patterns. A 320-acre inverted nine-spot pattern is also planned for the eastern Peripheral Wedge Zone with portions of the area initially developed on an inverted five-spot pattern. As in the case of the Flow Station 2 waterflood, the five-spot patterns may evolve into nine-spot patterns as infill drilling proceeds.

Reservoir and facilities conceptual design studies for development of the Eileen - West End area of the field have continued during the past year. Preliminary facility study results indicate that the preferred method of processing West End production would be to utilize Gathering Center 2, rather than a separate production facility. Reservoir and geologic studies have continued to address such questions as well spacing, waterflooding, and production performance estimates. Pressure measurements being obtained from the observation well Kuparuk 22-11-12 are being incorporated into the reservoir simulation work.

The Flow Station 3 Injection Project, an enhanced oil recovery project employing miscible gas displacement, commenced operation in December 1982. Injection of miscible fluids was initiated in well 13-19 on December 30, 1982.

The project area encompasses some 3650 acres in the downdip area of Flow Station 3 and consists of eleven inverted nine-spot injection patterns. A total of 60 wells are included in the Project, of which 42 are producers, 7 are water injectors and 11 are water/miscible gas (WAG) injectors. As of May 31, 1983, all Project wells with the exception of 1 producer had been drilled. In addition, an observation well has been drilled in the Project area for surveillance purposes. The remaining producer is currently being drilled. Facilities associated with the project include two 15 MMSCFD compressors and one 14 MBD liquid pump which can provide up to 49 MMSCFD of miscible injectant for injection into eleven WAG wells at Drill Site 13. The water for the WAG wells and initial water injection into the seven upstructure water injectors is being provided by existing produced water facilities at Flow Station 3 supplemented with approximately 50 MBWPD of gas-lifted Sadlerochit aquifer water from four Drill Site 14 source water wells. Gas-lift gas to produce the source water wells is provided by three Solar compressors located at Flow Station 3 which have a nominal capacity of approximately 45 MMSCFD. During the month of May 1983, injection rates in the Project averaged approximately 42 MMSCFD of miscible injectant and 62 MBWPD in the water injectors.

On May 26, 1983 an explosion and fire occurred in the Injection Module, thereby halting injection into the Project area. Damages are currently being assessed and future courses of action are being evaluated.

RECEIVED

JUN 30 1983

DIV. OF MINERALS & ENERGY MGMT.
ANCHORAGE, ALASKA

ARCO Alaska, Inc.
P. O. Box 100360
Anchorage, AK 99510

Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, AK 99502

June 29, 1983

Director
State Of Alaska
Division of Minerals & Energy Management
Department of Natural Resources
Pouch 7-005
Anchorage, AK 99510

EXH E-1

Subject: EXHIBIT E-1
PLAN OF DEVELOPMENT AND OPERATION FOR
LANDS OUTSIDE THE INITIAL PARTICIPATING
AREAS - PRUDHOE BAY UNIT AGREEMENT
STATE OF ALASKA

Sohio Alaska Petroleum Company and ARCO Alaska, Inc., as Operators of the Prudhoe Bay Unit, respectfully submit herewith a progress report for the twelve (12) months ending June 1983, as required by the final paragraph of Exhibit E-1 to the Prudhoe Bay Unit Agreement.

Sincerely,

Leland E. Tate

L. E. Tate
Vice President
Engineering and Extension
Exploration
ARCO Alaska, Inc.

P. J. Martin

P. J. Martin
Vice President
Operations and Engineering
Sohio Alaska Petroleum Company

CSR
Attachment

PLAN OF DEVELOPMENT AND OPERATION FOR LANDS
OUTSIDE THE INITIAL PARTICIPATING AREAS
PROGRESS REPORT: JULY 1, 1982 TO JULY 1, 1983

LISBURNE RESERVOIR

During the report period, the extended production test on West Bay State No. 1 well was completed. The West Bay test, located on lease no. ADL 28302, has increased our knowledge of the productivity of the Lisburne Reservoir. The results of the test are confidential and are on file with the Alaska Oil and Gas Conservation Commission.

Two new delineation wells as described below have been spudded in the Lisburne region during 1983.

<u>Owner</u>	<u>Well Name</u>	<u>Bottom-Hole Location</u>
ARCO/Exxon	South Point St. 1	18-11-15
ARCO/Exxon	Pingut St. 1	24-11-15

These wells will be extensively cored, logged, and tested to further appraise the Lisburne Reservoir continuity and productivity.

A conceptual facility design is in progress and plans are underway to coordinate a preliminary facility design during 1983. In addition, detailed geological, geophysical and reservoir engineering studies are underway by the affected Working Interest Owners to evaluate the structure, areal extent, continuity and productivity of the hydrocarbon-bearing reservoirs within the Lisburne.

KUPARUK RESERVOIR

During the report period, the Kuparuk interval was penetrated by the following Prudhoe Bay Unit Sadlerochit development wells drilled from S-Pad located in Section 35, T12N, R12E. These wells summarized below are drilled on State leases and the results are on file with the State.

<u>WELL</u>	<u>BHL</u>	<u>SPUD DATE</u>	<u>COMPLETION DATE</u>	<u>TOTAL DEPTH (MD)</u>	<u>LEASE ADL #</u>
S-10	35-12-12	6/17/82	7/4/82	9,715'	28257
S-9	34-12-12	7/5/82	7/25/82	10,480'	28258
S-8	35-12-12	7/26/82	8/21/82	9,740'	28257
S-14	36-12-12	8/22/82	9/16/82	11,216'	28257
S-13	2-11-12	9/18/82	10/12/82	11,503'	28260
S-7	2-11-12	10/13/82	11/10/82	10,810'	28260
S-6	2-11-12	11/11/82	12/3/82	10,810'	28260

Over the last year, incremental Kuparuk logging and/or side wall cores have been obtained in two of the S-Pad wells. Consideration is being given to acquiring additional data in upcoming S-Pad area wells. This type of information will be used in studies to determine the economic potential of development of these Kuparuk reservoir accumulations in the Unit area.

Approximately 651 line miles of seismic data have been acquired within the Unit during the report period, primarily for Sadlerochit development. Approximately 10 percent of this data is located in the S-Pad area and may be useful in defining the structure and areal extent of the Kuparuk interval in that area. This data is being processed and will be interpreted before the end of 1983.

Detailed geological and geophysical studies of the Kuparuk River Formation in the Prudhoe Bay Unit are continuing, incorporating the Kuparuk information and results from the drilling mentioned above. Development alternatives for the Kuparuk reservoir are currently being evaluated for future consideration.

NORTH PRUDHOE BAY (PERMO-TRIASSIC)

During the report period, there were no wells drilled and there was no seismic data acquired in the North Prudhoe Bay (Permo-Triassic) area. Results of ARCO's N. Prudhoe State #2, drilled in April 1982, located on lease no. ADL 28301, have been interpreted and are being incorporated in an updated geophysical interpretation of the area.

ENDICOTT RESERVOIR

As reported in the Endicott section of the Prudhoe Bay Unit Plan submitted on March 30, 1982, it is apparent that the Endicott Reservoir underlies leases in the northeast corner of the Prudhoe Bay Unit, the adjacent Duck Island Unit, as well as State leases that are not currently included in any Unit. As a consequence, many Endicott activities are being undertaken cooperatively by the Endicott group of leaseholders (Sohio Alaska Petroleum Co., ARCO Alaska, Inc., Exxon Corporation, Union Oil Company of California, Amoco Production Company, Sealaska Inc., Cook Inlet Region Inc., Nana Regional Corporation Inc., and Doyon Ltd.), and the 1982 plan addressed these joint activities. As a further consequence, additional Endicott Plans of Development, substantially consistent with the Prudhoe Bay Unit Plan were submitted to the Director on behalf of the Duck Island Unit and ADL 312828 leaseholders on May 6, 1982, and October 12, 1982, respectively.

The Endicott group is currently working towards unitization of the Endicott Reservoir. In this regard, consideration is being given to contraction of leases ADL 34633, ADL 34634 and ADL 34636 from the Prudhoe Bay Unit, and

simultaneous expansion of the Duck Island Unit to include leases ADL 34633, ADL 34634 and ADL 34636, as well as ADL 312828 and ADL 312834.

Summary of Work

In general, work has progressed in accordance with the 1982 plans, as detailed below. The work program is geared towards continued evaluation of the prospect such that Endicott owners will be in a position to appraise development feasibility after receipt of major permits and other approvals.

Work Conducted Since Previous Plan

(i) Drilling Activity

Sag Delta 10 was successfully drilled to a bottom-hole location in 31-12-17 and proved to be a valuable delineation well for the Endicott Reservoir. The entire reservoir section in the well was logged and cored, and the well was production tested, prior to curtailment of drilling activities at breakup, when the well was suspended and the drilling rig removed. Following drilling, core analysis, petrological analysis, and fluid analyses have been carried out.

Since, contrary to expectations, Sag Delta 10 was tested immediately following drilling, it was not necessary to move a rig to Endeavour Island in the winter of 1982/83 for this purpose. Accordingly, the testing of Sag Delta 9 (also on Endeavour Island), which would have been carried out had a rig been on the island, was not conducted.

(ii) Geophysical

The data acquisition phase of a 3-D seismic survey covering approximately 26 square miles over the entire Endicott Reservoir area was successfully conducted in the first and second quarters of 1983.

Since March 1982, approximately 20 miles of earlier 2-D data has been reprocessed, a lower mileage than predicted. This is because the need for the reprocessing is largely alleviated by the availability of the higher quality 3-D data.

(iii) Engineering Studies

The Endicott group has completed two major engineering studies for the conceptual design of facilities and pipelines necessary to support development of the Endicott Reservoir. Additionally, several geotechnical studies were conducted in conjunction with the conceptual design effort. The purpose of the conceptual work was to evaluate the feasibility and cost of various development alternatives. Following completion of the conceptual design contracts in September 1982, the Owners agreed on the major development concepts to be carried forward for further design and project permitting. These concepts include:

- One main production island (west).
- One satellite drilling island (east).
- Gravel causeway from west island to shore and east island.
- Waterflood intake integral to west island.
- Base Operation Camp offshore on west island.
- Main Construction Camp onshore in the Sag Delta area.
- Sales pipelines routed onshore through the Sag Delta.

(iv) Environmental/Permits

The Endicott group conducted various environmental field studies both onshore and offshore during 1982 for the purpose of obtaining a better understanding of the environment in the project area and establishing a data base of information from which to prepare an Environmental Impact Statement (EIS). An initial project permit application was filed in September 1982 with the Corps of Engineers. At the same time, an Engineering Overview and companion Environmental Overview were issued to the Corps and the various permitting agencies. The Engineering

Overview describes the base case development plan carried through conceptual engineering; the Environmental Overview describes the environmental setting and the changes that may occur as a result of the project development. The filing of the Corps permit application effected the start of the EIS process in which the Corps was established as the lead agency. A third party contract was established for preparing the EIS.

A National Pollutant Discharge Elimination System (NPDES) permit application was filed with the EPA in January 1983. This application covers the proposed discharge of drilling muds and cuttings offshore in the project area. A Prevention of Significant Deterioration (PSD) permit application was filed with the EPA in March 1983. This application provides an estimation of the air emissions resulting from the project development as well as an assessment of the impact of these emissions on air quality in the project area.

Public scoping meetings for the EIS were held in January and February 1983 at various locations in the State. The scoping process for the EIS concluded in April 1983.

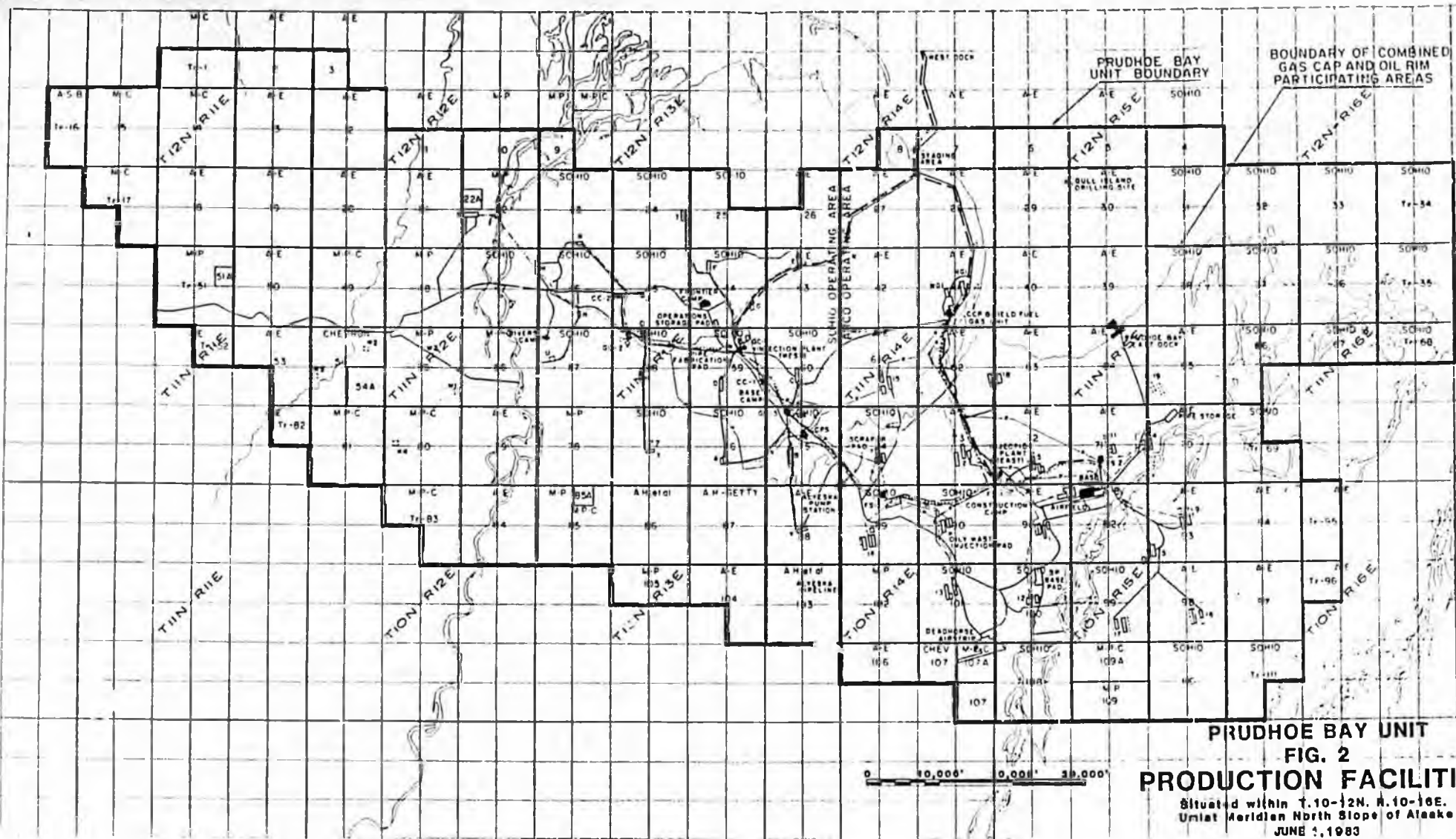
Work In Progress

(i) Engineering Studies

The Endicott Owners began an engineering contract on June 1, 1983, for further design of facilities and pipelines necessary to develop the project. The major thrust of work during 1983 will be performing design optimizations on the selected development concepts. At the same time, additional geotechnical studies and field tests will be conducted to support the preliminary design effort.

(ii) Environmental/Permitting

The Corps of Engineers is currently preparing the Draft EIS . The Endicott Owners are preparing additional permit applications for submittal to the various permitting agencies.



PRUDHOE BAY UNIT
FIG. 2
PRODUCTION FACILITIES
 Situated within T.10-12N. R.10-16E.
 Umat Meridian North Slope of Alaska
 JUNE 1, 1983

LEGEND

DRILL PADS AND DRILL SITES		PIPELINES		OTHER FEATURES	
EXISTING	POSSIBLE FUTURE	EXISTING FLOWLINES	POSSIBLE FUTURE FLOWLINES (with access roads)	ROADS (with bridges where required)	TRANSMISSION LINE (69 KV)
PRODUCTION FACILITIES		OIL GATHERING AND OIL TRANSIT LINES	GAS INJECTION LINE	WATER INJECTION PLANT	LOW PRESSURE SEAWATER LINES
EXISTING	POSSIBLE FUTURE	GAS GATHERING AND GAS TRANSIT LINES	POSSIBLE FUTURE OIL AND GAS GATHERING LINES	FUEL GAS LINE	NGL DISTRIBUTION LINE

LEASE LEGEND

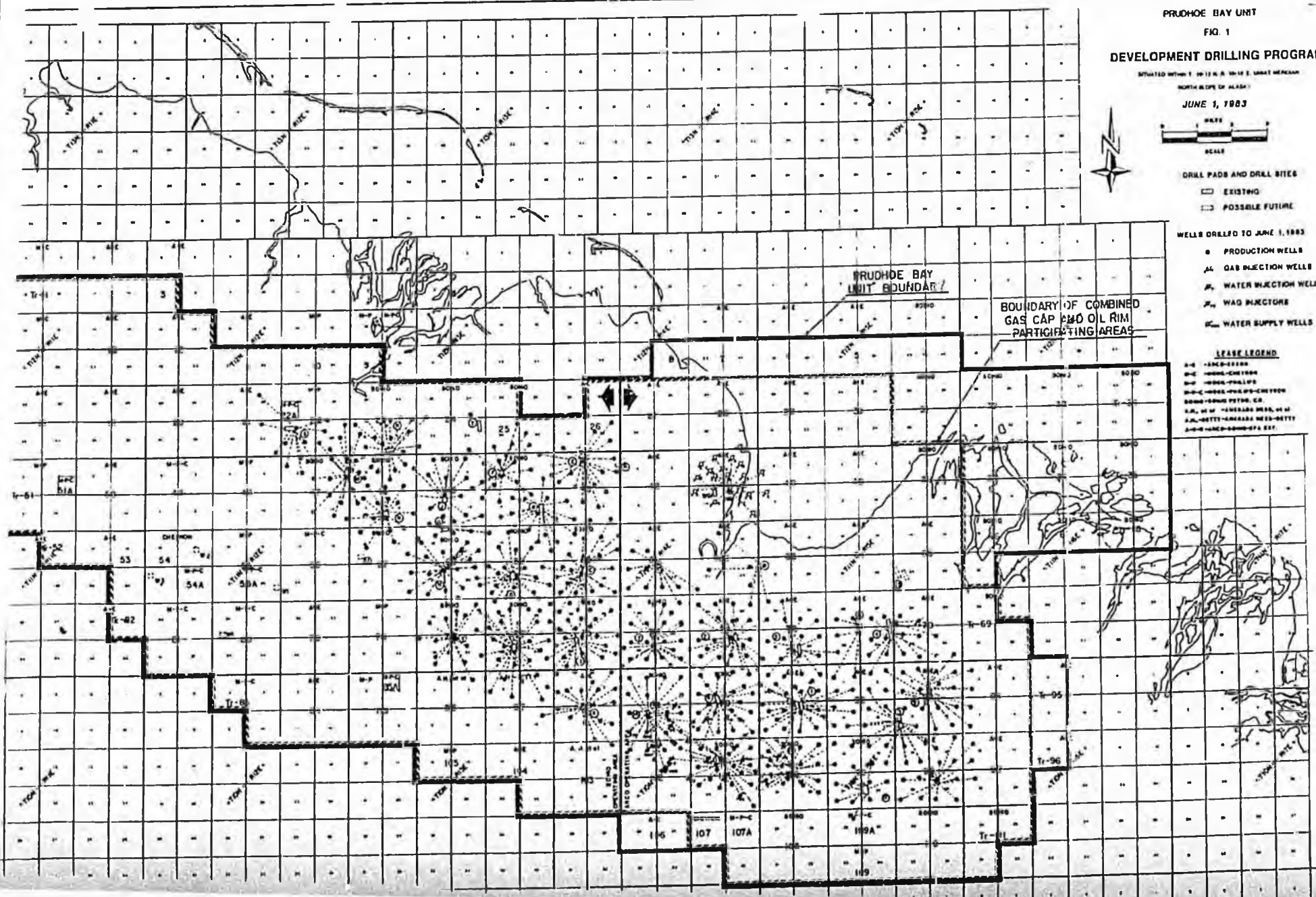
A-E	Arco-Exxon
M-C	Mobil-Chevron
M-P	Mobil-Phillips
M-P-C	Mobil-Phillips-Chevron
SOHIO	Sohio Petro. Co.
A.H., et al	Amerada Hess, et al
A.H.-GETTY	Amerada Hess-Gatty
A-S-B	Arco-Sohio-BPAE

PRUDHOE BAY UNIT
 FIG. 1
 DEVELOPMENT DRILLING PROGRAM
 SITUATED WITHIN T. 101 N. R. 10-14 E. 10-14 S. GREAT MESA
 NORTH SLOPE OF ALASKA
 JUNE 1, 1983



- DRILL PADS AND DRILL SITES
- ◻ EXISTING
 - ◻ POSSIBLE FUTURE
- WELLS DRILLED TO JUNE 1, 1983
- PRODUCTION WELLS
 - △ GAS INJECTION WELLS
 - ▲ WATER INJECTION WELLS
 - ✱ WAG INJECTORS
 - ⊞ WATER SUPPLY WELLS

- LEASE LEGEND
- 41-E - 41-00-0-0000
 - 41-C - 40-00-0-0000
 - 41-F - 40-00-0-0000
 - 41-G - 40-00-0-0000
 - 41-H - 40-00-0-0000
 - 41-I - 40-00-0-0000
 - 41-J - 40-00-0-0000
 - 41-K - 40-00-0-0000
 - 41-L - 40-00-0-0000
 - 41-M - 40-00-0-0000
 - 41-N - 40-00-0-0000
 - 41-O - 40-00-0-0000
 - 41-P - 40-00-0-0000
 - 41-Q - 40-00-0-0000
 - 41-R - 40-00-0-0000
 - 41-S - 40-00-0-0000
 - 41-T - 40-00-0-0000
 - 41-U - 40-00-0-0000
 - 41-V - 40-00-0-0000
 - 41-W - 40-00-0-0000
 - 41-X - 40-00-0-0000
 - 41-Y - 40-00-0-0000
 - 41-Z - 40-00-0-0000



Prudhoe Bay Unit Files

ARCO Alaska, Inc.
P. O. Box 360
Anchorage, Alaska 99510

Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, Alaska 99502

June 29, 1982

Director
State of Alaska
Division of Minerals & Energy Management
Department of Natural Resources
703 E. Northern Lights Boulevard
Anchorage, Alaska 99503

DIV. OF MINERALS & ENERGY MGMT.
ANCHORAGE, ALASKA

Subject: PRUDHOE BAY UNIT
ANNUAL PROGRESS REPORT

RECEIVED
JUL 1 1982
DIV. OF MINERALS & ENERGY MGMT.
ANCHORAGE, ALASKA

Dear Sir:

In accordance with the requirements of the Prudhoe Bay Unit Agreement, we are submitting an annual progress report of the activities performed under the Plan of Development included as Exhibit 'E'.

If you should have questions regarding this report, please do not hesitate to contact the undersigned.

Sincerely,

G. L. Downey
G. L. Downey
Vice President
Engineering and Extension
Exploration
ARCO Alaska, Inc.

Paul J. Martin
P. J. Martin
Vice President
Operations and Engineering
Sohio Alaska Petroleum Company

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Attachment

PRUDHOE BAY UNIT
ANNUAL PROGRESS REPORT

In accordance with provisions of the Prudhoe Bay Unit Agreement, this Annual Progress Report has been prepared for submission to the Director, Division of Minerals and Energy Management, Department of Natural Resources. The purpose of this report is to summarize the previous years' activities under the plan of development and operation, which is incorporated in the Unit Agreement as Exhibit 'E'.

Oil Production

Since June 1, 1981, production to the TAPS line has been essentially continuous, at approximately 1.5 MMSTB/D, with only a few brief shortfalls occurring during the past year. These shortfalls have normally been associated with planned maintenance activities of the Prudhoe Bay field or TAPS facilities. During the period of June 1, 1981 through May 31, 1982, a total of 557 MMB of oil and condensate was delivered to the pipeline at an average rate of 1527 MSTB/D. Total net oil and condensate production from the field from April 1, 1977 (the effective date of the Prudhoe Bay Unit) through May 31, 1982 is 2323 MMB, including approximately 5.08 MMB to the crude oil topping plant.

Gas Production And Injection

From June 1, 1981 through May 31, 1982, a total of 677 BSCF of gas was produced from the field and 622 BSCF was reinjected into the gas cap of the Prudhoe Oil Pool. The majority of the remaining 55 BSCF was used as fuel, purge and pilot gas, with only a minor amount flared. All flaring is being held to practical minimums and has been in accordance with the rules established by the State of Alaska, Division of Oil and Gas Conservation in Conservation Order No. 145-A of January 12, 1978.

Water Production

Water production between June 1, 1981, and May 31, 1982, totalled 14 MMB, of which 1.4 MMB was produced intentionally from two Drill Site 1 wells in the Eastern Operating Area for produced water injectivity tests in well DS 5-17. Excluding water production from the two source water wells, total water production rose slightly from 9.4 MMB the previous year to 12.6 MMB the past year. The injectivity tests were completed by December 1981, and since that time, the DS 5-17 well has been utilized for routine produced water injection into the Sadlerochit at Flow Station 1. The other Flow Stations/Gathering Centers continue to use disposal wells with injection into the Cretaceous/Tertiary Sands.

Additional Wells And Facilities

As of May 31, 1982, a total of 356 wells were drilled, completed, and connected for production to their respective Flow Stations/Gathering Centers, of which 190 and 166 wells were located in the Eastern and Western Operating Areas, respectively. Also, another 135 wells, 52 in the East and 83 in the West, had been drilled and completed but were awaiting perforation. The bottomhole locations of the oil producing wells drilled as of May 31, 1982 are shown in Figure , together with possible future 160-acre locations.

As of May 31, 1982, drilling was in progress at Drill Sites 2, 13, 14, and 15 in the Eastern Operating Area. In the Western Operating Area drilling was in progress on Well Pads A, B, C, E, and S.

Figure 2 shows the location of existing production facilities, pipelines, roads, bridges, airstrips and base camps, together with facilities under construction and possible future facilities.

CONTINUED DEVELOPMENT

Well and facility additions are continuing in order to ensure that adequate field capacity is available to meet oil pipeline demand up to a maximum annual average oil rate of 1.5 MMSTB/D, plus condensate production, in accordance with Conservation Order No. 145. Field facilities will also be available to accommodate gas pipeline deliveries of 2.0 BSCFD when a gas conditioning plant and pipeline are completed.

Current plans envision approximately 940 development wells for the main area of the field, or 460 wells in the Western Operating Area and 480 wells in the Eastern Operating Area. These well count estimates include current and future 160-acre development wells, infill wells, and water injection wells. Current projections of drilling activity levels indicate most of the wells will be drilled by 1987. Continued development drilling will require the expansion of some drill sites/well pads as well as the construction of new ones. Facilities to tie-in these wells are either being designed or fabricated and will be installed coincidental with drilling operations. For example, following the 1982 sealift, facilities will exist to accommodate 654 wells; following the 1985 sealift, current planning envisions 906 wells can be accommodated.

Effective July 1, 1981, Rule 2 of Conservation Order No. 145 was amended to allow drilling on reduced spacing, and subsequently in late-1981 the Unit began infill drilling at select drill sites. Reservoir model results continue to support significant infill development; however, ultimate well requirements will depend on reservoir performance.

Low pressure systems will be installed in annual increments covering several years. The first increment, currently being installed at Flow Station 2, is scheduled to be operational in mid-1982. Current plans indicate that all three Flow Stations in the Eastern Operating Area will have low pressure capability by 1984. In the Western Operating Area, all Gathering Centers will have low pressure capability by 1984, with the first increment being installed at Gathering Center 2 in 1983. Low pressure systems will be provided to drill sites/well pads on a priority basis beginning in 1982. Based on the current plan approximately 28 well pads will have low pressure capability by 1984, with the remainder by 1986.

Current plans provide for the initiation of gas lift at X Pad in the Western Operating Area beginning in late-1982 with the commissioning of a 35 MMSCFD capacity compressor. In 1984 the gas lift system will be expanded fieldwide with the installation of a nominal 375 MMSCFD capacity compressor at Flow Station 3, gas lift transmission lines between Gathering Centers and Flow Stations, and a tie line connecting the two sides of the field. Currently, it is expected that other large increments of artificial lift will be commissioned in 1986 and 1987. Current predictions envision gas lift usage to be 1.3 to 1.5 BSCFD by 1987; however, further study and field performance is required to better define the timing of future increments and the ultimate gas lift system requirements. Artificial lift will be provided to drill sites/well pads on a priority basis beginning in 1982. Based on the current plan, approximately 13 drill sites/well pads will have gas lift capability by 1984, with the remaining completed by 1987.

Gas injection capacity has been increased with the addition of a ninth low-stage compressor at the Central Gas Injection Plant. This unit, which was delivered on the 1981 sealift, is currently undergoing final check-out.

Including this unit, there are now nine low stage and four high stage units at the Central Gas Injection Plant. Eighteen gas injection wells are currently available, including fourteen at the North Pad and four at the West Pad. Adequate gas injection well capacity is available for the added compression capacity along with normal injection well maintenance or stimulation downtime.

The initial increments of produced water injection facilities for Gathering Centers 2 and 3 arrived on the 1981 sealift and are expected to become operational during the second half of 1982. Produced water injection facilities have previously been installed at the three Eastern Operating Area Flow Stations, with routine injection operations starting at Flow Station 1 in January 1982. Injection service at Flow Stations 2 and 3 is expected to commence later during 1982 and early 1983, respectively, when sufficient sustainable produced water volumes become available. By the end of 1986, total installed injection capacity, including spares, is expected to be approximately 1.65 MMBWPD, with about 900 MBWPD capacity in the Western Operating Area and 760 MBWPD capacity in the Eastern Operating Area. Ultimate injection of produced water is currently projected to be about 1.0 MMBWPD.

The Prudhoe Bay Unit source waterflood project remains on schedule for the planned mid-1984 start-up of source water injection. Initial rates are anticipated to be 1.5-2.0 MMBWPD in 1984. The basic waterflood plans and implementation schedule presented in the May 1980 Prudhoe Oil Pool Rules Hearing and the December 1980 Secondary Recovery Permit Application are unchanged at this time. The design and fabrication of the seawater treating plant and East and West side injection facilities are on schedule, and designs have retained flexibility to accommodate any of the water injection patterns under consideration. The 1981 environmental monitoring program results have

been provided to the Corps of Engineers, and planning for the 1982 monitoring program is in the final stages of development. Additionally, development of a comprehensive reservoir surveillance program has begun in conjunction with detailed waterflood implementation planning.

Reservoir analysis continues to focus on optimization for the three major waterflood areas of the Northwest Fault block, the Peripheral Wedge Zone, and the Flow Station 2 area. Reservoir model studies have continued to explore variables such as well spacing, injection volumes, and patterns, in order to maximize recoveries in project areas. Also, recent field performance and drilling data continue to be incorporated into studies to improve the reservoir description. The DS 5-17 high rate water injection test has now been concluded with offset well performance approximating predictions. Additionally, analysis of the 60-day injection test in well DS 5-14, which was conducted to investigate the effects of cold water injection (40°F) into the Sadlerochit, suggests no adverse effects due to either hydrate formation or thermal fractures. More injectivity data will be gathered throughout the field as additional wells are converted to produced water injection.

During the past year, reservoir and facilities conceptual design studies for development of the Eileen - West End area of the field have continued. Also, the Kuparuk well, Sec. 22, T11N, R12E was converted for use as a pressure observation well. Associated with the conversion, production tests were performed on the well and the fluid, pressure, and production data obtained are being integrated with the areal geologic data to improve the ongoing reservoir and facilities studies. These studies are being directed towards well spacing, waterflooding and optimum facilities development.

ARCO Alaska, Inc.
P. O. Box 360
Anchorage, Alaska 99510

Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, Alaska 99502

June 29, 1982

Director
State of Alaska
Division of Minerals & Energy Management
Department of Natural Resources
Pouch 7-005
Anchorage, Alaska 99510

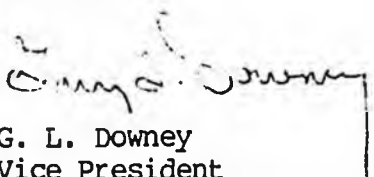
JUL 1 1982
DIV. OF MINERALS & ENERGY MGMT.
ANCHORAGE, ALASKA

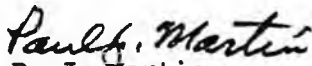
Subject: EXHIBIT E-1
PLAN OF DEVELOPMENT AND OPERATION FOR
LANDS OUTSIDE THE INITIAL PARTICIPATING
AREAS - PRUDHOE BAY UNIT AGREEMENT
STATE OF ALASKA

Dear Sir:

Sohio Alaska Petroleum Company and ARCO Alaska, Inc., as Operators of the Prudhoe Bay Unit, respectfully submit herewith a progress report for the twelve (12) months ending June 1982, as required by the final paragraph of Exhibit E-1 to the Prudhoe Bay Unit Agreement.

Sincerely,


G. L. Downey
Vice President
Engineering and Extension
Exploration
ARCO Alaska, Inc.


P. J. Martin
Vice President
Operations and Engineering
Sohio Alaska Petroleum Company

cc
Attachment

PLAN OF DEVELOPMENT AND OPERATION FOR LANDS
OUTSIDE THE INITIAL PARTICIPATING AREAS
PROGRESS REPORT: JULY 1, 1981 to JULY 1, 1982

Lisburne Reservoir Area

During the report period, the Lisburne formation was penetrated by two wells, ARCO's North Prudhoe Bay State No. 2 and Sohio's Sag Delta No. 9. The North Prudhoe Bay State No. 2 is on Lease No. ADL 28301, located 2377' FNL and 2401' FWL, Section 26, T12N, R14E, UPM. The well was spudded April 30, 1982 and drilled to a total depth of 10,780' MD and suspended on June 3, 1982. The Sag Delta No. 9 is on Lease No. ADL 312828 located 2230' WEL and 336' SNL, Section 36, T12N, R16E, UPM. The well was spudded October 15, 1981 and drilled to a total depth of 14,100' MD and suspended on January 25, 1982. The results of these two wells are confidential and are on file with the Alaska Oil and Gas Conservation Commission.

ARCO is currently conducting an extended production test on the West Bay State No. 1 well located on Lease No. ADL 28302. Facilities were constructed to separate and meter the produced fluids and mechanical problems in the well were corrected allowing production to begin in March 1982. Facility modifications were required and now the production test has been in continuous operation for almost three months. Several more months of production are planned before concluding the test.

The results of the two recently drilled wells are currently being interpreted and their incorporation with existing data on the Lisburne will aid our understanding of the structure and continuity of hydrocarbon-bearing reservoirs within the carbonate section. The results of the production test will improve our understanding of the reservoir characteristics and production nature of the Lisburne, and provide information for conceptual development studies. Continuing geological analyses of the Lisburne during the past year have emphasized the very complex characteristics of the reservoir. Therefore, continued reservoir, geophysical, and geological studies are planned and further delineation drilling may be required to define the development potential of the Lisburne formation.

Kuparuk Reservoir

During the report period, the Kuparuk interval was penetrated by one well, ARCO's Eileen State No. 1 on Lease No. ADL 28254. The well is located 1700' FNL and 600' FWL, Section 18, T12N, R12E, UPM. The well was spudded February 21, 1982 and drilled to a total depth of 9,900' MD and suspended on March 18, 1982. The results are confidential and are on file with the Alaska Oil and Gas Conservation Commission.

Detailed geologic and geophysical studies of the Kuparuk River formation are continuing, including incorporating the results of the drilling discussed above. Conceptual facility design studies for the West End Sadlerochit are scheduled for completion in the near future. Different conceptual development alternatives for the Kuparuk reservoir area are being considered both in conjunction with and separate from West End Sadlerochit development.

North Prudhoe Bay (Permo-Triassic) Reservoir

During the report period, the North Prudhoe Bay (Permo-Triassic) Reservoir was penetrated by one well, ARCO's North Prudhoe Bay State No. 2 on Lease No. ADL 28301. The well is located 2377' FNL and 2401' FWL, Section 26, T12N, R14E, UPM. The well was spudded April 30, 1982 and drilled to a total depth of 10,780' MD and suspended on June 3, 1982. The results are confidential and are on file with the Alaska Oil and Gas Conservation Commission. The information from the North Prudhoe Bay State No. 2 will need to be interpreted and studied in order to understand the structure and stratigraphy of the area prior to formulating additional plans for the area.

During the report period, a 270-mile seismic program was completed. The data is being processed and will be used to help define the limits of accumulation.

PRUDHOE BAY UNIT
 (S-1)
 DEVELOPMENT DRILLING PROGRAM

LEASE LISTING

100	101	102	103	104	105	106	107	108	109	110	111	112	113	114	115	116	117	118	119	120	121	122	123	124	125	126	127	128	129	130	131	132	133	134	135	136	137	138	139	140	141	142	143	144	145	146	147	148	149	150	151	152	153	154	155	156	157	158	159	160	161	162	163	164	165	166	167	168	169	170	171	172	173	174	175	176	177	178	179	180	181	182	183	184	185	186	187	188	189	190	191	192	193	194	195	196	197	198	199	200
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JUNE 1, 1962



PRUDHOE BAY UNIT BOUNDARY

BOUNDARY OF COERDED GAS CAP AND OIL RIM PARTICIPATING AREAS

WELL PADS AND WELL SITES

□ EXISTING

□ POSSIBLE FUTURE

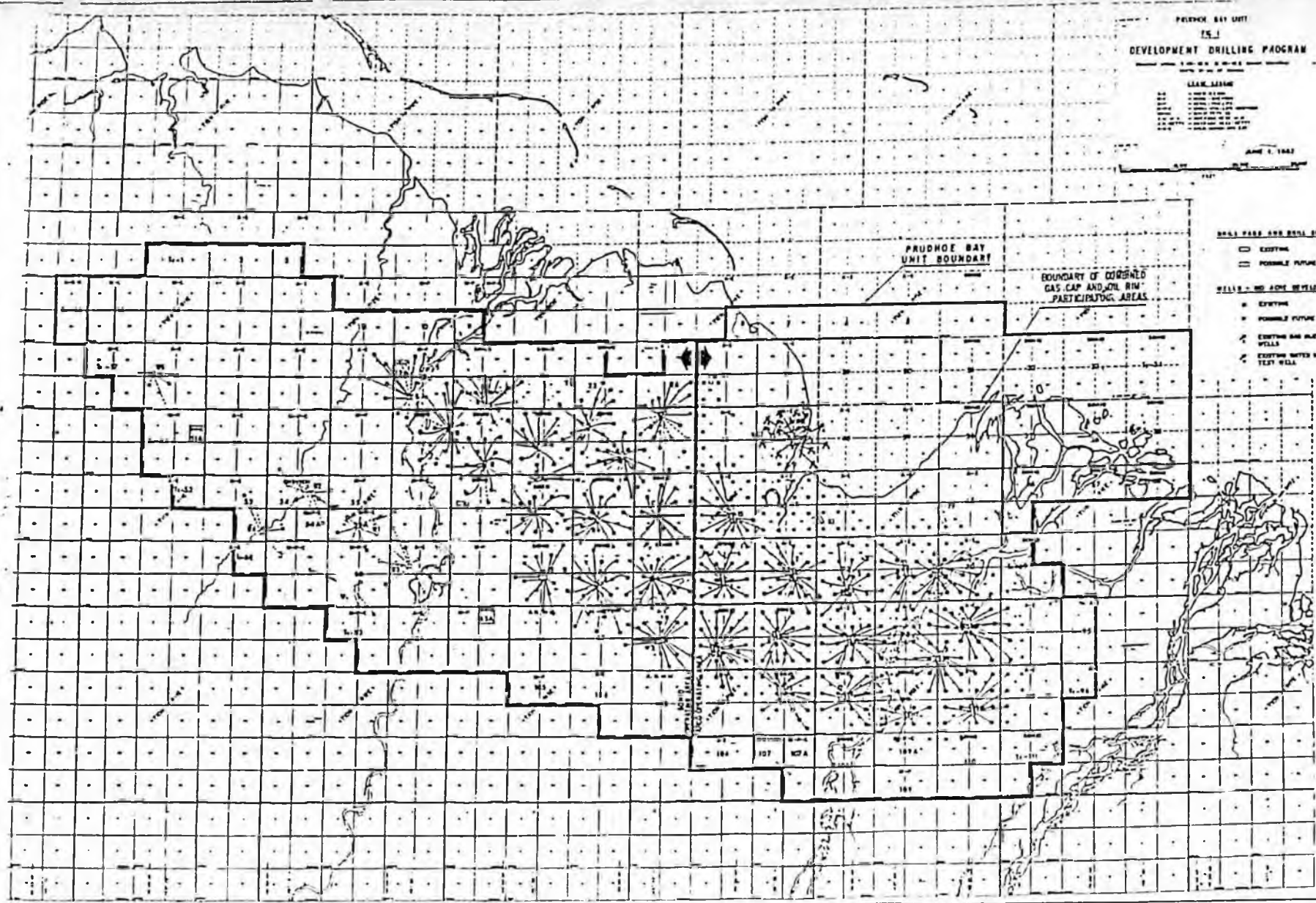
WELLS - NO. ACRE DEVELOPMENT

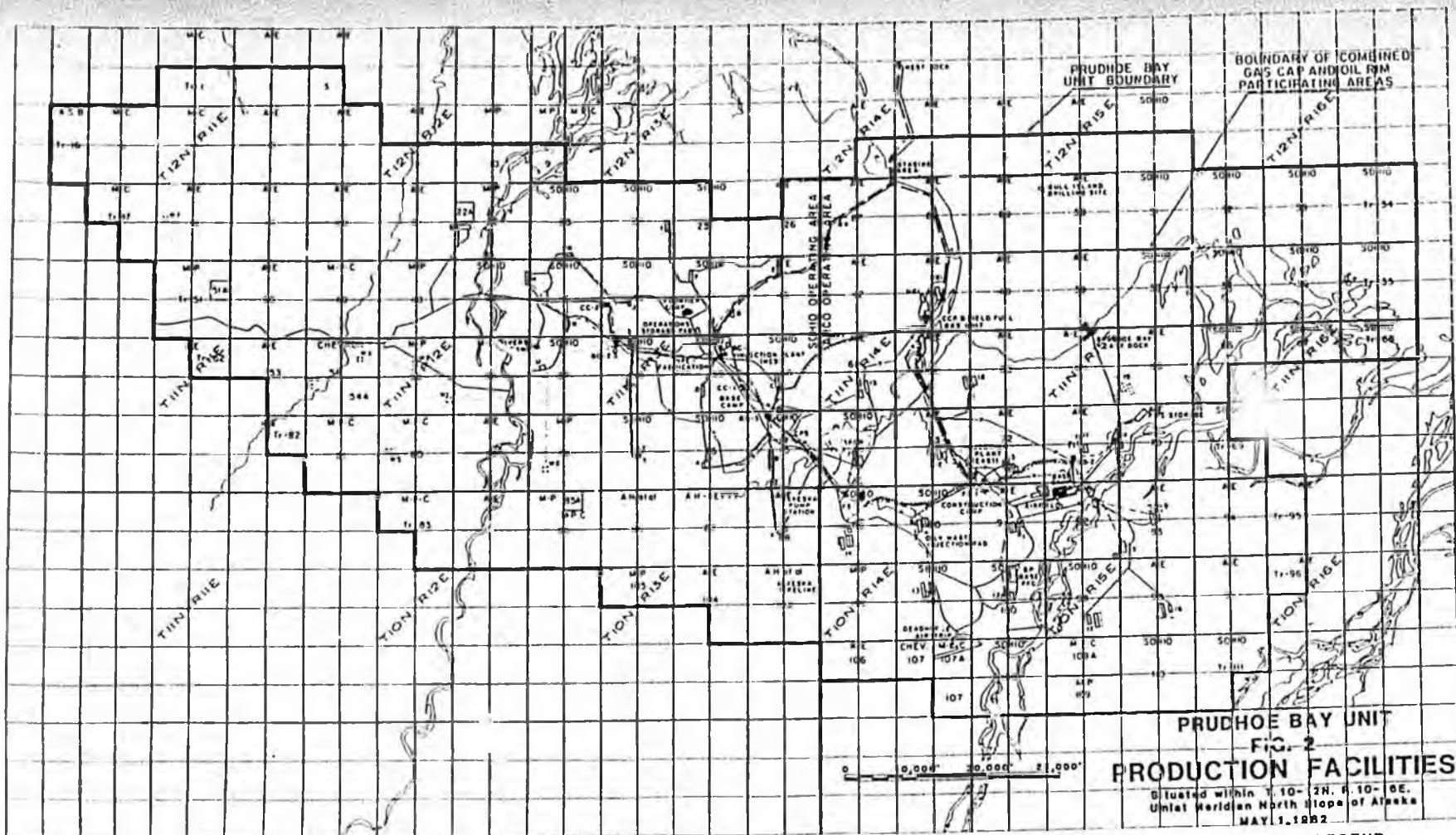
• EXISTING

• POSSIBLE FUTURE

• EXISTING GAS INJECTION WELLS

• EXISTING WATER INJECTION TEST WELLS





PRUDHOE BAY UNIT
 FIG. 2
PRODUCTION FACILITIES
 Situated within T. 10- 2N. R. 10- 16E.
 Untied Meridian North Slope of Alaska
 MAY 1, 1982

LEGEND

- DRILL PADS AND DRILL SITES**
- EXISTING
 - POSSIBLE FUTURE
- PRODUCTION FACILITIES**
- EXISTING
 - POSSIBLE FUTURE

- PIPELINES**
- EXISTING FLOWLINES
 - POSSIBLE FUTURE FLOWLINES (with access roads)
 - OIL GATHERING AND OIL TRANBIT LINES
 - GAS INJECTION LINE

- GAS GATHERING AND GAS TRANBIT LINES**
- POSSIBLE FUTURE OIL AND GAS GATHERING LINES
 - FUEL GAS LINE

- OTHER FEATURES**
- ROADS (with bridges where required)
 - TRANSMISSION LINE (69 KV)
 - WATER INJECTION PLANT
 - LOW PREBBURE SEAWATER LINES

LEASE LEGEND

- A-E Arco-Esson
- M-C Mobil-Chevron
- M-P Mobil-Phillips
- M-P-C Mobil-Phillips-Chevron
- SOHIO Sohio Petro. Co.
- A.H., et al Amerada Hess, et al
- A.H.-GETTY Amerada Hess-Getty
- A-B-G Arco-Sohio-BPAE

ARCO Alaska, Inc.
P. O. Box 360
Anchorage, AK 99510

Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, AK 99502

March 30, 1982

Commissioner
State of Alaska
Department of Natural Resources
Pouch M
Juneau, AK 99811

RECEIVED
MAY 2 1982
DIV. OF MINERALS & ENERGY MGMT.
ANCHORAGE, ALASKA

EXHIBIT E-1
PLAN OF DEVELOPMENT AND OPERATION FOR
LANDS OUTSIDE THE INITIAL
PARTICIPATING AREAS - PRUDHOE BAY UNIT
AGREEMENT, STATE OF ALASKA,
JULY 1, 1982 - MARCH 31, 1987.

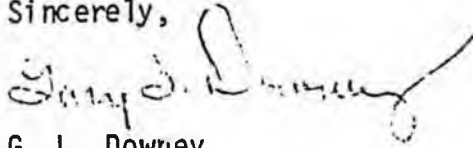
Dear Mr. Katz:

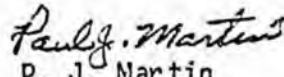
Pursuant to the requirements of Article 4.2 of the Prudhoe Bay Unit Agreement, the Unit Operators hereby submit a five (5) year Plan of Development and Operation for lands outside the initial Participating Areas. This Plan covers the period July 1, 1982 through March 31, 1987.

In summary, efforts on behalf of the tract owners have satisfied the terms and conditions of the current Exhibit E-1. The results obtained to date have been valuable, but inconclusive, due to the complexity of the areas under study. In that regard, the plans defined herein are designed to adequately delineate the development potential of these areas in a timely and logical manner.

We hope the report will be satisfactory and we will be pleased to discuss it with you and your staff.

Sincerely,


G. L. Downey
Vice President
Engineering and Extension
Exploration
ARCO Alaska, Inc.


P. J. Martin
Vice President
Operations and Engineering
Sohio Alaska Petroleum Company

csr
Attachments

xc: Division of Minerals and Energy Management

PLAN OF DEVELOPMENT AND OPERATION
FOR LANDS OUTSIDE THE INITIAL PARTICIPATING AREAS
PRUDHOE BAY UNIT AGREEMENT, STATE OF ALASKA

Lands within the Unit Area that are not in the initial Participating Areas shall be developed and operated pursuant to the Plan of Development and Operation ("the Plan"), which is described below:

GENERAL

The hydrocarbon-bearing reservoirs that have been discovered within the Lisburne, North Prudhoe Bay (Permo-Triassic), Kuparuk River and Endicott formations which extend over lands in the Unit Area beyond the initial Participating Areas continue to be investigated to determine their potential. At the effective date of this document these reservoirs have not been proven to be capable of producing oil or gas in sufficient quantities to justify Working Interest Owners in developing and producing them. Additional wells, tests and studies are planned from July 1982 through March 1987 to further evaluate the suitability of these reservoirs for the formation of additional Participating Areas.

The Plan for these other reservoirs may include the drilling of additional wells both inside and outside the initial Participating Areas. As provided in the Unit Agreement, a well drilled on any part of a lease, any portion of which lease is included in the Unit Area, is deemed a well drilled in satisfaction of Exhibit E-1, regardless of whether or not such well is located in the Unit Area; provided that it is shown to the satisfaction of the Director that the bottom hole target of the well will provide a reasonable geologic test or geologic information significant to Unit Operations. Further, any information gained as a result of a well drilled outside the Unit

boundary may be used to contribute to the overall assessment of any reservoir wholly or partly within the Unit Area.

The terms of this Plan shall cover the time period from July 1, 1982 through March 31, 1987. As in previous years, on July 1, 1983 and each year thereafter, Unit Operators will file progress reports describing operations under this Plan for the preceding twelve (12) month period.

I. LISBURNE RESERVOIR

a) Introduction

The Lisburne Group lies stratigraphically beneath the Sadlerochit and is composed of sediments of Upper Carboniferous (Pennsylvanian-Mississippian) age. From the current geologic interpretation it appears the reservoir consists of hydrocarbon bearing dolomitic zones within a carbonate sequence.

Due to the overall structural configuration in the Prudhoe Bay Region, the hydrocarbon bearing zones of the Lisburne are generally found in tracts in the northeast sector of the Prudhoe Bay Unit; however, to date the reservoir has not yet been delineated.

Prior to April 1977, 6 wells were drilled that penetrated the Lisburne. Over the last 5 years an additional 12 wells have been drilled in the region in an attempt to define the stratigraphic and structural nature of the reservoir as well as establish various reservoir characteristics.

b) Operations To Date

i) Drilling Activity (April 1977 to April 1982)

The following wells were drilled in the Lisburne region during the last 5 years (The results of all wells are filed with the State of Alaska):

<u>OWNER</u>	<u>WELL NAME</u>	<u>PTOM HOLE LOCATION</u>
ARCO/Exxon	Gull Is. St. 2	33-12-15
Sohio	Sag Delta 2	10-11-16
Sohio	Sag Delta 2A	10-11-16
Sohio	Sag Delta 3	35-12-16
Sohio	Sag Delta 4	35-12-16
ARCO/Exxon	West Bay St. 1	1-11-14
Sohio	Niakuk 3	13-12-16
ARCO/Exxon	Term Well A	33-12-14
Marathon/Amerada Hess	Sag Delta 8	22-12-16
Sohio	Sag Delta 5	36-12-15
Sohio	Sag Delta 7	31-12-17
Sohio	Sag Delta 9	19-12-17

ii) Geophysical Studies

Over the period April 1977 to April 1982 more than 250 miles of new seismic was shot in the region and more than 100 miles of pre-1977 data reprocessed.

c) Work in Progress

An extended production flow test being performed in well ARCO/Exxon West Bay St. No. 1 will continue for a period of up to 6 months to evaluate the reservoir characteristics and productive nature of the Lisburne Reservoir. Also, Sohio's Sag Delta No. 10 is being drilled to location 31-12-17.

d) Future Plans

i) Drilling Activity

During the next year Working Interest Owners plan to drill at least one well within the Unit Area for further appraisal and delineation of the Lisburne Reservoir. The drilling of further wells will be dependent on studies outlined below as well as the results obtained from well tests.

ii) Studies

Detailed geological, geophysical and engineering studies will be continued by affected Working Interest Owners to evaluate the structure, areal distribution and continuity of hydrocarbon-bearing reservoirs within the Lisburne carbonates. This will include seismic studies such as reprocessing and interpretation of current data as well as additional shooting in conjunction with drilling operations. Based on these studies, further plans for Lisburne Reservoir development will be determined.

II. KUPARUK RESERVOIR

a) Introduction

Geophysical mapping and well data have suggested a trend, although highly faulted, of potential hydrocarbon-bearing accumulation(s) which may extend to and beyond the Prudhoe Bay Unit boundary in the northwest of the Unit area. To date 11 wells have been drilled in this area which evaluate the Kuparuk Reservoir.

b) Operations To Date

i) Drilling Activity

The following wells have been drilled in the Kuparuk region (The results of all wells are filed with the State of Alaska):

<u>OWNER</u>	<u>WELL NAME</u>	<u>BOTTOM HOLE LOCATION</u>
Mobil/Phillips	West Kuparuk St. 1	3-11-11
ARCO/Exxon	Beechy Pt. St. 1	20-12-12
Mobil/Phillips	N. Kuparuk St.	26-12-12
Mobil/Phillips	Kuparuk 9-11-12	9-11-12
Mobil/Phillips/Chevron	Kuparuk 7-11-12	7-11-12
Mobil/Phillips/Chevron	Term Well C	3-11-12
Chevron	Chevron Tract 18-11-12	18-11-12
Mobil/Phillips	Mobil/Phillips Tract 15-11-12	15-11-12
Mobil/Chevron	35-29E	29-12-11
ARCO/Exxon	Beechy Pt. St. 2	20-12-12
ARCO/Exxon	Drillpad S-3	27-12-12

ii) Geophysical Studies

In addition to the aforementioned drilling, 225 miles of seismic was shot to evaluate the Kuparuk Reservoir both inside and outside the Prudhoe Bay Unit.

c) Work In Progress

At the time of preparation of this report, ARCO/Exxon have just completed the drilling of Eileen State No. 1 well to a bottom hole location in 7-12-12 in an attempt to confirm the presence of hydrocarbons on the Eileen-Milne structural trend. The results of this well are presently being evaluated.

Detailed geologic and geophysical studies of the Kuparuk River formation are continuing. Different development alternatives are being considered in conjunction with the conceptual facility design studies for the West End Sadlerochit development.

d) Future Plans

Consideration is being given to the drilling of further wells along the Eileen-Milne structural trend to evaluate the areal limits of the separate hydrocarbon accumulations found at Beechy Point No. 1 well and in the Milne Unit. Further studies of the structure and stratigraphy of the trend will continue and will incorporate the evaluation of Eileen State No. 1. Based on the results of these studies, the drilling of additional delineation wells and seismic exploration may be undertaken.

III. NORTH PRUDHOE BAY (PERMO-TRIASSIC) RESERVOIR

a) Introduction

The North Prudhoe Bay (Permo-Triassic) Reservoir lies in that part of the Prudhoe Bay Unit which is north of and adjacent to the

Prudhoe Bay ult. Geophysical mapping in is area has, in part, defined several highly faulted features. Five wells have been drilled in the area to help evaluate these structural complexities.

North Prudhoe Bay St. No. 1 well encountered hydrocarbons in sufficient quantities to justify further investigation.

b) Operations To Date

i) Drilling Activity

The following wells have been drilled in the North Prudhoe Bay region (The results of all wells are filed with the State of Alaska):

<u>OWNER</u>	<u>WELL NAME</u>	<u>BOTTOM HOLE LOCATION</u>
ARCO/Exxon	North Prudhoe Bay St. 1	23-12-14
ARCO/Exxon	Gull Is. 1	21-12-15
ARCO/Exxon	West Beach St. 3	19-12-15
Sohio	Niakuk 1	26-12-15
Sohio	Niakuk 1A	26-12-15

ii) Geophysical Studies

Approximately 200 miles of seismic data has been shot in this area, 90 miles of which is 3-D seismic. Additionally, 65 miles of this data has been reprocessed.

c) Work In Progress

Another well, North Prudhoe Bay St. No. 2, has been permitted by ARCO/Exxon and will be drilled in Section 26-12-14 in the second quarter of 1982. This well will aid in the confirmation of the limits of this accumulation and supply data for studies concerning development planning. A 265 mile seismic program is in progress to help define the limits of the accumulation. Additionally, geological and geophysical studies are in progress and different development alternatives are being studied.

d) Future Plans

Studies of the structure and stratigraphy will continue following completion of both the drilling and geophysical programs. Based on these results, additional wells and geophysical studies may be proposed.

IV. ENDICOTT RESERVOIR

a) Introduction

Exploration activity in the northeast Prudhoe Bay Unit Area and adjacent leases has established the existence of a significant hydrocarbon accumulation in the Sag River Delta area of the Beaufort Sea. The accumulation was encountered in a Mississippian (pre-Permo-Triassic) system, hereafter described as the Endicott Reservoir. Subsequent delineation work has indicated that the Endicott Reservoir underlies leases in the northeast corner of the Prudhoe Bay Unit Area, and in the adjacent Duck Island Unit, as well as State leases that are not currently included in any unit. Current indications are that the Endicott does not extend into the initial Participating Areas within the Prudhoe Bay (Permo-Triassic) Reservoir.

The parties holding interests in leases in the area believed to be underlain by the reservoir are Sohio Alaska Petroleum Company, ARCO Alaska Inc., Exxon Corporation, Union Oil Company of California, Amoco Production Company, Koniag Inc., Sealaska Inc., Cook Inlet Region Inc., Nana Regional Corporation Inc. and Doyon Limited ("Sag Delta/Duck Island Group"). Of the Sag Delta/Duck Island Group, Sohio is the only party which holds leases in the Prudhoe Bay Unit Area that are underlain by the Endicott Reservoir.

Although the current plan is submitted pursuant to the Prudhoe Bay Unit Agreement, the joint approach to development being taken requires that the plan address some operations which occur outside the Prudhoe Bay Unit Area. To the extent that such operations pertain to the ultimate potential development of the Endicott Reservoir, such operations should be considered as leading to the ultimate potential development of Prudhoe Bay leases. The Sag Delta/Duck Island Group has agreed to proceed jointly in planning the potential development of the Endicott prospect.

b) Operations To Date

i) Drilling Activity

The following wells have been drilled on State leases to the objective formation (The results of all wells are filed with the State of Alaska):

<u>OWNER</u>	<u>WELL NAME</u>	<u>BOTTOM HOLE LOCATION</u>
Sohio	Sag Delta 2	10-11-16
Sohio	Sag Delta 3	35-12-16
Sohio	Sag Delta 4	35-12-16
Exxon/ ARCO	Duck Island 1	05-11-17
Exxon, et al	Duck Island 2	04-11-17
Sohio/ Cook Inlet/ Doyon/ Koniag/ Nana/ Sealaska	Sag Delta 7	31-12-17
Exxon, et al	Duck Island 3	10-11-17
Sohio, et al	Sag Delta 9	19-12-17

ii) Geophysical Studies

A substantial quantity of seismic data has been acquired since 1977 on leases within and adjacent to the Prudhoe Bay Unit Area to aid in the interpretation of the Endicott structure. Ninety-five miles of new data has been acquired by Sohio, sole account, approximately 50 miles of new data was acquired through trade, and Sag Delta/Duck Island leaseholders

participated in a joint industry group gathering some 84 additional miles of survey. In addition to this new data, some 110 miles of pre-1977 surveys have been processed by Sohio. Duck Island Unit Owners will, by Spring 1982, have acquired approximately 160 miles of new data and have reprocessed about 50 miles of pre-1977 data.

c) Work In Progress

i) Drilling Activities

Currently, Sohio is drilling Sag Delta No. 10 to a bottom hole location in 31-12-17. This well is expected to be completed in early 1982.

ii) Studies

Under the auspices of the Sag Delta/Duck Island Group, two major engineering studies are being undertaken with engineering contractors for conceptual design of the facilities and pipelines that would be necessary to support development of the Endicott Reservoir. Additionally, several geotechnical and environmental contracts are in progress to study the project area in conjunction with the conceptual design effort. The purpose of this work is to evaluate the feasibility and cost of various development alternatives. Also, joint company task forces have been formed to deal with permitting issues.

d) Future Plans

i) Drilling Activity

During the 1982-83 winter season, Sohio plans to conduct extensive production tests on both Sag Delta Nos. 9 and 10. This work will provide further definition of the productive capability of the Endicott Reservoir and will provide fluid samples from the reservoir which will be utilized in facility design.

ii) Geophysical Studies

A 3-D seismic survey covering 15-30 square miles is now being considered. Also, reprocessing of up to 100 miles of earlier 2-D data is planned.

iii) Studies

Conceptual engineering design work is expected to be completed in late 1982. Following a review of this work, if development appears feasible, detailed design would begin in 1983. Preliminary conceptual work will be used to initiate the permitting process. A Sag Delta/Duck Island Group task force has been assigned to coordinate the permitting effort, which is viewed by the group as the critical path item in a project execution schedule.

Individual companies are continuing to evaluate the structure, areal distribution and properties of the Endicott Reservoir. Based on the results of these studies, additional delineation wells or seismic activity may be proposed.

Prospect development is contingent upon assessment of commerciality and the timeliness with which permits can be granted. Engineering aspects of the schedule, namely the time required for design, procurement, fabrication, construction and drilling are under study as part of the conceptual engineering effort.

The current assessment is that the earliest date for startup of oil production would be in the late 1980s.

WEDNESDAY
-M-

The Anchorage Times

18 pages***

THURSDAY EVENING, APRIL 7, 1988

25¢

*tributed
by
K. Mitchell*

ELF impact overstated by at least \$222 million



By Robert Laurie
Times Journal Bureau

JUNEAU — A department of Revenue analysis of an oil company tax formula overstated its impact on state revenues by at least \$222 million over the next five years.

Revenue officials say they made a mistake when calculat-

ing the effect of the Economic Limit Factor on the state's income.

A measure to repeal the ELF is awaiting action in the Senate State Affairs committee, and has been the subject of a great deal of debate in the legislature.

Supporters of the measure have extensively quoted a fiscal

note prepared last month by the department to accompany the bill. The note said the state is missing out on over \$187 million this year because of the ELF. It shows the state losing over \$27 million next year. By fiscal year 1993, it shows the state would lose over \$1.4 billion.

But a revised fiscal note pre-

pared this week shows shortfalls of \$150 million in fiscal year 1988, a \$30 million difference; and \$152 million in 1989, a \$75 million variation.

The new note showed that by 1993, the state will miss out on \$1.2 billion, depending on the price of oil.

"Quite frankly, it was a mis-

take," said Chuck Logsdon, chief petroleum economist with the Department of Revenue. "We discovered the mistake and corrected it."

Logsdon said the department based its initial calculations on a wrong version of the bill.

"We had a version of the bill See ELF bill, page A-9

ELF bill

Continued from page A-1

that dinged Kugaruk too hard," said Logsdon.

The bill went through three revisions as it made its way through the House last year. The version that finally passed the House eliminated a provision that would have increased the severance tax on Kugaruk.

The error, coupled with revised oil price assumptions based on the March revenue forecast, account for the differences, according to Logsdon. He said the changed oil price expectations play more of a role in the later years of the analysis.

Revenue Commissioner Hugh Malone said the mistake was just that.

"It wasn't an attempt on the part of the department or anyone to provide misinformation," assured Malone. He says the initial analysis was released outside of normal channels, before it could be checked for errors.

"We try to provide accurate information to legislators," he continued. That's why, he said, the department attached a chart showing how the impact differs depending on the price of oil.

Senate President Jan Faiks, who opposes the ELF measure, said she was aware of the mistake.

"No, I'm not surprised by it at all," she said. "The Department of Revenue has not been issuing accurate information."

Faiks said the department's revenue forecasts have also been flawed.

House Speaker Ben Grussendorf, who has led a House majority caucus campaign favoring the bill, said his argument remains essentially unchanged.

He said the \$150 million will go a long way toward balancing the budget next year.

Robert B. Atwood
President and Publisher

Elaine Atwood
Assistant Publisher

William J. Tobin
Vice-President, Editor-in-Chief

For Your Information,

ELF IS WORKING,
AND WORKING WELL

The numbers game

YOU HAVE to understand the numbers game if you want to follow what's going on in Juneau in the battle over the budget — and the fight over all the various funds that make up the budget.

Gov. Steve Cowper and the House Democrats say the state is facing a horrible deficit because oil prices aren't high enough.

They say to fund the budget we must (1) spend the money now set aside in the Railbelt Energy Fund, (2) collect more taxes from the oil companies by altering the formula on which severance taxes are levied under the so-called Economic Limit Factor or (3) raid the earnings of the Permanent Fund.

defending ELF and the Railbelt Energy Fund and in the process staving off use of Permanent Fund earnings for a one-time budget pop, say none of these moves is necessary.

There is plenty of money in the till, the Republicans say, to fund a hold-the-line budget.

EVEN AT that, says the Senate majority, we can have a budget that is 3 percent higher than the current fiscal year — a boost that takes care of built-in, mandatory items that must be financed, such as the more than 200 new employees that will be required to staff the new Spring Creek Correctional Facility at Seward.

By holding the line at a 3 percent increase, and with the price of oil at \$15 a barrel, the Senate says there is no need to raise taxes, spend the Railbelt Energy money or dip into the Permanent

Fund earnings.

You only have to do that, they contend, if the governor has his way and gets a raft of new spending programs into the new budget.

What Gov. Cowper really is asking for, they say, is the money to hike this year's budget between 13 percent and 16 percent over the state's existing spending level.

If you go along with that, there indeed will be a deficit.

How big, however, is pretty hard to follow.

The reason is that the Department of Revenue runs different sets of figures at different times of the day.

THE NUMBERS are anything but clear, and some legislators are complaining there appears to be an almost deliberate attempt by the administration to befuddle the issue with figures that are apples and oranges.

It's a complex business, to be sure.

But for the general public, it can be reduced to a more simple and understandable level.

Given these economic times, can Alaska justify spending up to 16 percent more to finance governmental operations that it already is doing?

Or should Alaska look at this year as one to hold the line and spend no more than what is now available?

That presents an easy choice.

There's another option, of course, but it isn't being discussed in Juneau.

And that's reducing expenses by cutting the budget.

But don't hold your breath for that to happen.

place

State loss from ELF may double

By PATTI EPLER
Daily News reporter

A controversial oil tax program will cost the state about \$100 million more than first estimated, according to state petroleum economist Chuck Logsdon.

The Economic Limit Factor (ELF), designed as an incentive to encourage oil production as fields begin to decline, will cost the state about \$305 million in reduced severance taxes in fiscal years 1988 and 1989, about \$108 million more than state officials had figured on when they were factoring the tax reduction into the state revenue picture.

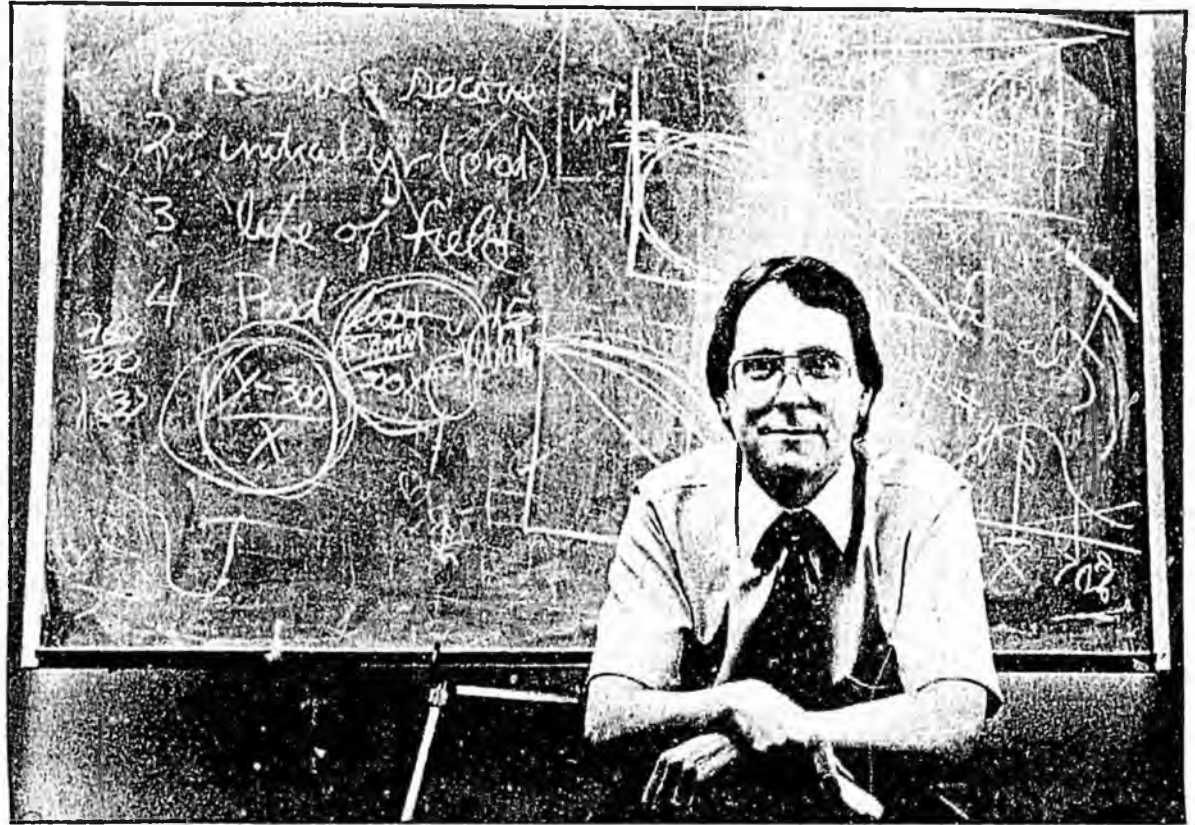
Logsdon said officials had underestimated the number of wells that North Slope producers planned to drill in those years.

Also, oil prices are higher than projected and production rates will be higher than expected, he said in a Feb. 19 memo to state Revenue Commissioner Hugh Malone.

However, state officials also have said that increased royalties to the state because of greater production in large part will offset bigger losses in severance tax revenue from a reduced ELF.

Since July, the ELF has been factored into tax computations on production from Prudhoe Bay, the largest oil field in North America and the source of most of the state's income.

The ELF is based on how much oil is produced from each well. Taxes drop as the number of barrels per well drops, which usually happens when a field declines.



Daily News file photo/Michael Penn

State oil price expert Chuck Logsdon

Logsdon said in the memo that "an aggressive drilling program such as that announced by the Prudhoe producers will keep production at the 1.54 million-barrel-per-day level but will do it with more wells than are currently required. For this reason, the severance tax rate will fall even though Prudhoe production will not."

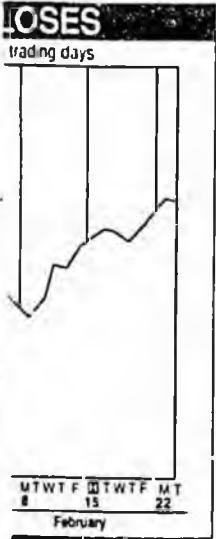
Based on current assumptions about oil prices, production rates and number of wells for Prudhoe Bay, Logsdon said, his office now is projecting that the cost to the state of the ELF will be \$147 million in FY 1988 and \$158 million in 1989.

"These estimates are considerably higher than those made last spring when the legislature was considering ELF legislation," he wrote. "The reason is a combination of higher assumed prices, production in FY 1989, and a greater number of wells."

In June, petroleum economists had estimated the cost to the state to be \$101 million in FY 1988 and \$96 million in FY 1989.

Logsdon said in an interview his staff had underestimated the number of wells to be drilled by about 100. They also used lower oil

See Page B-5. ELF



after rally
YORK — The market shed little ground Tuesday and ran into some resistance trying to extend its recent run. "The market is a time out," Alfred E. Loman, a chief analyst for Edwards & Inc. in St. Louis. The Dow's average of industrial stocks slipped a few points on Monday to 2,700. The market's rally had risen more

ELF: State losses from tax program double

Continued from Page B-4

prices in their calculations, he said.

The memo to Malone updates the revenue projections, he said.

It was written partly because of recent announcements by North Slope producers of increased spending and drilling plans and

partly because there has been renewed interest by legislators in a House bill that would change the ELF tax program, he said.

"It became apparent we were going to have to explain to somebody a drop in our severance tax estimates for reasons other than our usual price drop," Logsdon said.

reservations by 6 p.m. today

AHFC director to speak

Dr. Ron Lehr, executive director of the Alaska Housing Finance Corp., will be the guest speaker at a Thursday meeting

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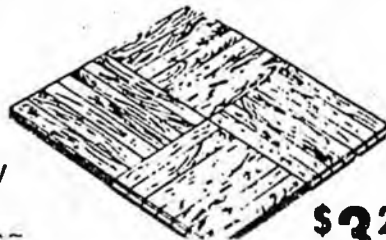
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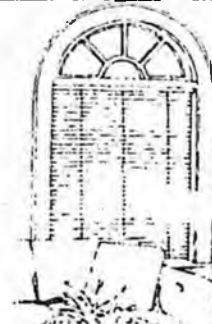
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The Senate Special Committee
Invites you to an ove

Alaska International

Marketing, Tourism & Trade State

Senate Special Committee

Senator Rick U

Senator Mitch Abood

Senator Fre

Presentations Schedule

9:00 - 11:30 AM

Bob Coe, President,

Duty Free Shoppers, Alaska Division

Bob Poe, Deputy Commissioner,

Department of Transportation, State of Alaska

Hugh Gellert, Director,

Division of Tourism, State of Alaska

Keith Fernandez, Marketing Director,

Anchorage Convention and Visitors Bureau

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Business

Wednesday, April 6, 1968, The Anchorage Times

Survey reveals extent of ELF impact

Businesses report dramatic rise in jobs, sales since implementation

By Ray Tyson
Times Business Editor

A telephone survey of companies that do business with Alaska's oil industry shows that employment and sales among the companies have risen sharply since June, when the controversial Economic Limit Factor took effect.

Results of the survey conducted by the Alaska Support Industry Alliance clearly indicate the ELF, a state tax incentive designed to encourage more drilling, has contributed to an increase in business among companies that supply goods and services to Alaska's major oil companies.

The governor and Democratic-controlled House want to eliminate the ELF, claiming the so-called tax break

is unfair and that the state needs the revenue to balance its budget.

More than 70 percent of the companies responding to the survey conducted March 29 and 30 said they want the ELF to continue, while 86.1 percent support a stable tax climate, Alliance spokesman Bill Webb said.

"We can't say ELF solved all (the problems), but we certainly can say it was a big part of the equation," Webb said.

The Alliance is a non-profit organization representing more than 200 oil, gas and mining companies in Alaska.

Companies included in the survey have employees who work on the North Slope, Webb said. Of the 100 contacted by telephone, 79 responded to the questionnaire.

During the 10 months that ELF has been in effect, the companies reported a total gain of 636 employees, for a 12.9 percent increase. They expect an additional 368 employees by June, for a total of 1,002 jobs, a 20.2 percent increase since the ELF took effect, Webb said.

Of the companies surveyed, 54.4 percent reported an increase in sales; 25.3 percent a decrease; 19 percent no change; and 1.2 percent did not respond. The average increase per company was 22.2 percent.

"Sales were encouragingly up," Webb said.

The average company surveyed has been doing business in Alaska 17.2 years.

"There were few companies under

10 years with a 1.1 in the 25 to 40-year range," Webb said.

Of the 79 respondents, 65.3 percent were incorporated in Alaska, he said.

Had it not been for the tax incentive, Webb said it is unlikely North Slope oil production would have been increased to the current 2.2 million barrels a day.

"If the state didn't have that flow, it would have lost the (additional) royalties and taxes," he said.

"They are winning with the ELF. But it's amazing that they can't see it. I'm surprised with the legislature. Maybe we're guilty. Perhaps we should have done this survey earlier and educated the people."

Office Correspondence

STANDARD
ALASKA PRODUCTION

TO: G. N. Nelson

DATE: February 23, 1988

FROM: T. K. Williams T.K.W.

CC NO:

SUBJECT: Daily News Article on the ELF

YOUR REF:

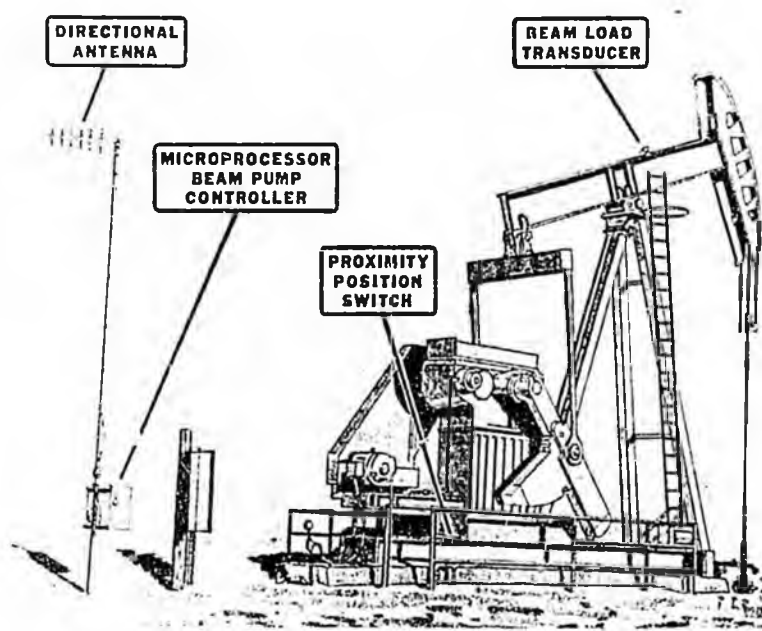
The following points are offered regarding the article in this morning's Anchorage Daily News (copy attached) saying that effects of the Economic Limit Factor (ELF) on production tax revenue from Prudhoe Bay are nearly \$100 million more in FY 88 and 89 than the state had previously estimated. The difference is said to be due to the state's underestimation of the number of producing wells. All other things being equal, the ELF does reduce the effective tax rate as the number of producing wells increases because production from Prudhoe Bay may not increase above the field's maximum efficient rate (MER). A copy of the state memo on which the article is based is also attached.

- o Prudhoe Bay is actually in decline -- only the additional production from the new wells that have been drilled and the work on existing wells have prevented current production rates from falling below the MER of 1.5 MMB/D of oil.
- o Besides sustaining current levels of production, each new well at Prudhoe Bay adds approximately one million barrels to the field's total recoverable reserves.
- o The ELF was intended to prevent fields from being less than fully developed; it provides a positive incentive to drill, and it has succeeded: over \$300 million (most of which will flow directly into the Alaskan economy) will be spent in drilling new wells fieldwide during this year and next.
- o As the article acknowledges, the tax effects are largely offset by increased royalty revenues to the state as the result of higher current production.
- o No unnecessary wells are being drilled simply for the sake of the ELF benefit -- under the ELF the tax saving from one additional well is approximately \$0.2 million a year for Prudhoe Bay (based on the state's current assumptions as to well count and prices during FY 89), while the drilling cost is over 10 times greater.
- o Even with the ELF, the effective production tax rate for Prudhoe Bay is the second highest in the United States (approximately 12.26% versus Louisiana's 12.5% -- Texas is 4.6%).

Attachments

O+G Incl
1987 Data Book

Production/Enhanced Recovery Report



Artist sketch of remote pumping well. Transducer on walking beam is connected by cable to microprocessor/UART modem for transmission of data via radio to host computer.

Increased rate of EOR brightens outlook

Jim Leonard
Production Editor

Continuing its growing presence, enhanced oil recovery (EOR) now contributes about 604,800 bbl to total U.S. daily crude oil production (Table 1) from 512 reported projects (Table 2). The 1986 OGJ survey reveals another 108 domestic EOR projects are targeted to commence over the next 1-2 years (Table A).

Total reported EOR projects have increased 37.3% over the 1984 survey, and total reported daily production has increased 31.2%. EOR now represents over 6.8% of total domestic crude production. Following is a closer look at activity in the various EOR categories and some technology highlights.

Thermal

The OGJ survey reveals 201 active U.S. thermal projects produce nearly 480,000 b/d. In terms of market share, the steam process alone contributes 77.5% to total domestic EOR of 604,000 b/d.

Of course the magnitude of heavy oil reserves, improving technology, and maturity of the larger projects assure production dominance of the steam injection process for years to come.

Its increasing success over the past decade in terms of productivity and number of projects indicates its status as our most mature EOR technology.

Kern County. The focal point of domestic thermal operations is still Kern County, California, where "huff and puff" gave birth to today's steam drive technology.

As a project matures, production capacity increases in most cases. Texaco's (formerly Getty's) Kern River field reports nearly 98,500 b/d of EOR as this steam project approaches maturity. The 1984 survey reported 95,000 b/d.

Shell Oil Co.'s South Belridge field steam project produced 70,000 b/d of EOR when OGI published the results of its 1984 survey. Our 1986 survey reports this project's EOR production of 13 gravity oil at 89,000 b/d. And since Shell has no plans to reduce its commitment to research, improved technology will be followed by improved oil recovery.

Steam generation/cogeneration. Perhaps one of the biggest incentives California oil operators could have for expansion of thermal EOR is to have access to reliable, long term supplies of out-of-state natural gas for steam generation and cogeneration facilities.

Conversion of oil-fired steam generators to gas-fired would significantly increase EOR production as well as minimize environmental and pollution concerns.

There is a struggle under way for the California thermal EOR/cogeneration gas market. New intrastate contract carriage rates and terms give utilities an edge to meet the market with existing systems.

But producers still back interstate lines to avoid the risk of supply inter-ruptibility.

Gas projects

Total gas projects have increased a healthy 23.8% and production has increased 30.4% to over 108,000 b/d. These figures are all the more impressive considering that an unexpected number of operators declined to participate in the survey.

Permian basin. Although mobility/confinement and reservoir heterogeneity present giant challenges, operators have bet over \$2 billion that the CO₂ miscible process will succeed in various fields throughout the Permian Basin.

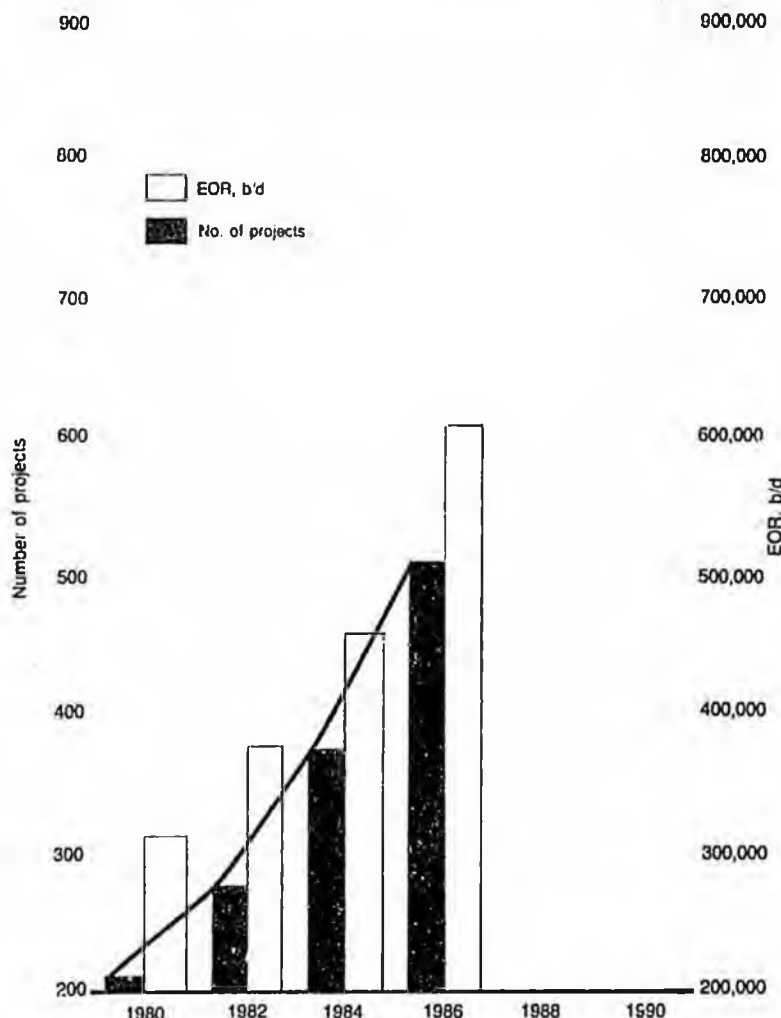
The high mobility of injected CO₂ has been a major contributing cause for past project failure, but research has identified foams and gels which have proved economically successful for mobility control and sweep efficiency.

Meanwhile their use has also pointed to the need for a more detailed description of reservoir heterogeneity when evaluating for EOR via the CO₂ process.

The lag time between implementation and reservoir response indicates that the Permian Basin will not make its most significant contribution to EOR until the 1990s.

EOR progress in U.S.

Fig. 1



Prudhoe Bay. Arco's enriched hydrocarbon miscible project on the east side of Prudhoe Bay field has been in operation for a little over 2 years.

Although none of the current 65,000 b/d is classified as EOR (lag time), this project holds special significance.

As the project matures, the degree of success measured here in terms of EOR barrels to total production will suggest the magnitude of U.S. reserve potential in the Arctic region from proved reservoirs.

CO₂ immiscible. The number of CO₂ immiscible projects jumped 55.6% since our 1984 survey; however, their total EOR output is still small because most of the projects are relatively new.

Note that Texaco plans 27 new immiscible projects in South Louisiana for 1986-87.

Chemical processes

Gains in the polymer process are impressive in terms of production and number of projects. Production is up 49.7% to over 15,300 b/d, and number of projects increased to 178—up 67.9%. Alkaline and micellar-polymer projects declined both in number of projects and EOR production.

Micellar-polymer decline. The micellar-polymer (surfactant-polymer) flood process is complex, not thoroughly understood, prohibitively expensive, and requires a massive infusion of technological research.

Ordinarily the surfactant slug consists of petroleum sulfonates mixed with other chemicals and water. The purpose of the slug is to lower interfacial tension and displace residual oil that cannot be displaced by water alone.

The surfactant slug is displaced

Editorials

Needs help

Board, Administration, Medical make every effort to bring our it should have to meet a grow- meet past seven years, the question meet federal and state, as well as studied with costs and ability to consideration. Three outside firms sisted us in reaching the follow- l not only be considerably more benefit the hospital in their mis- sected over future years.

y up through the waiting list for ing. We now find ourselves in a have met every pre-funding, pre- re now ready to go to bid for con- our minds about the ability of the instruction this year. We are now ecision and funding will be pro- emunity in convincing the leg- rough our legislators, we do need t help if both individuals and or- ould take a moment to call our air support for funding for this

messages can be sent to our legis- ormation Office in the Borough

nts will count in keeping Kodiak good health care.

oil policy

, the largest and most prolific oil ved tremendous benefits from its , many municipal improvements nd hospitals, as well as govern- ly and the disabled.

the revenue from this field is for oil companies are increasing profitability in a tough oil market. llion has been directly transferred orporate treasuries of several ma- ough premature application of the

need school improvements and Legislature continues to allow a when our state revenues are in

the Legislature scheduled the tax es were rising and it was thought ine by 1987. Today it is clear that te, quite profitably, if the ELF is refused to act on an oil tax bill.

use of Representatives have both

participated in public hearings to examine the ELF - the economic limit factor which lowers the tax rate for marginally producing oil fields. Last year the House passed a bill, introduced at the Governor's request, that did two important things:

- * prevented large tax breaks for giant oil fields like Prudhoe and Kuparuk, where tax incentives aren't needed, and
- * provided a new tax incentive for production from every other known field in Alaska, including marginal fields such as Endicott, Lisburne, and Milne Point. The latter was shut down in 1987 because it was uneconomic.

This approach makes sense. *Forbes* magazine recently reported that Atlantic Richfield is one of the most profitable oil companies in the world - and guess where the company gets 67 percent of its oil? From Kuparuk and Prudhoe Bay. Tax breaks are simply unnecessary for these oil fields.

The chief executive of Atlantic Richfield recently boasted that the company's profits are the "best in the industry." The company has also publicly reported that it increased its Alaska production while reducing production from other sources. These aren't the actions of a company producing from a marginal property and suffering economically.

Meanwhile, British Petroleum last year completed its acquisition of Standard Oil. Now it owns 100% of that company, which gets 98% of its oil production from Alaska.

And, Kuwait's national oil company has purchased more than 20% of BP. These aren't the actions of corporations worried about the profitability and potential of Alaska oil and gas production.

Some industry representatives claim that the tax break has encouraged more drilling on the North Slope. No proof has been offered that the new drilling is providing Alaskans extra jobs or that the long-term production of Prudhoe and Kuparuk is being increased. Instead, we might just be seeing a more rapid depletion of oil and gas reserves.

Industry representatives also talk about "tax stability." They imply that there was a compact between the 1981 Legislature and the oil and gas industry to install a tax break in 1987. But, they neglect to mention that there were other issues - legislative instability, legal battles, and inaccurate production projections - that influenced the 1981 Legislature. At that time, then Governor Hammond said "as for the possible revenue effects in 1988 and beyond, I have full confidence in the ability of the Legislature to deal at that time with whatever is required to retain the state's 'fair share' of our oil wealth."

Clearly, the time has arrived for the legislature to take such action. Today's legislators have to deal with today's problems. With our sagging economy, people losing jobs and homes, and every district in the state needing road repairs, money for schools, hospitals and a host of other public necessities - we need revenues to fund these worthy projects. Where do we get this money?

Naturally, the oil industry supports tax changes when those changes benefit the industry. In 1981 the industry came to the Legislature (in a time of oil price inflation and under pressure of a lawsuit that questioned the state's tax structure) and asked for tax breaks. The Legislature responded by instituting a new "unitary" tax system. Since then, Alaskans have foregone billions of dollars worth of revenues that would have been collected under the former system.

Alaskans have a clear choice here: shall we continue to forfeit tax revenues that could be put to many purposes around the state? Or, shall we go ahead and collect taxes that won't harm the industry and will bring us back to where we stood a year ago?

I strongly support Governor Cowper's effort to rescind the oil tax break. I'm glad that the House and Governor are working together on a tax system that will truly serve the fair and equitable interests of all Alaska.

(Cliff Davidson represents Kodiak in the State House and is a member of the House Resources Committee.)

Today's Tidbit

SIGN OF CRIME

SEATTLE - A former preschool worker has been ordered to wear a sign around her neck about her sex offenses after she pleaded guilty to misdemeanor charges of sexually assaulting two girls.

BURGER SLIP

LONDON - A police officer who was given the slip by a discarded hamburger has won a damage claim against the operators of the London subway.

High Court Judge Alan Lipfriend ruled that London Regional Transport was negligent in failing to clear up potentially dangerous litter at Earls Court station. The amount of damages will be assessed later.

Graham Blakely, 26, alleged he was chasing pickpockets in August 1982 when he leaped down some stairs and skidded on the remains of a hamburger and its container, breaking his right leg.

ABOMINABLE SNOWMAN

A British mountain climber set off for the Himalayas to find out whether the Abominable Snowman is myth or monster.

Chris Bonington intends to return to the 23,237-foot Menglungtse, where last year he found footprints from an unidentified creature on a failed attempt to climb the mountain.

"It would be fantastic if we could come back with some proof," he said.

Bonington and a five-man team discovered 7-inch-by-4-inch footprints 16,000 feet up the mountain last year. Periodic sightings of the creature, also known as the yeti, have been reported for decades.

130-POUND TUMOR

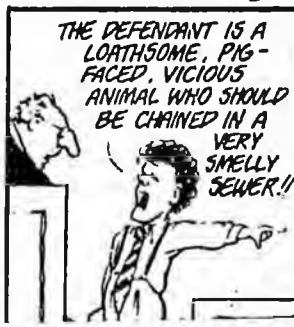
FORT WORTH, Texas - A woman who feared to seek medical help as a tumor swelled in her abdomen eventually doubled her weight before having the 130-pound malignant growth removed, her doctor said Wednesday.

In the three years preceding her operation, Barbara Louise Jones, 55, who is 5-foot-1 1/2, said she at first thought she was gaining weight, then realized something was seriously wrong.

But Miss Jones said she delayed seeing a doctor because she feared she would suffer the same type of painful death as her mother.

BLOOM COUNTY

by Berke Breathed

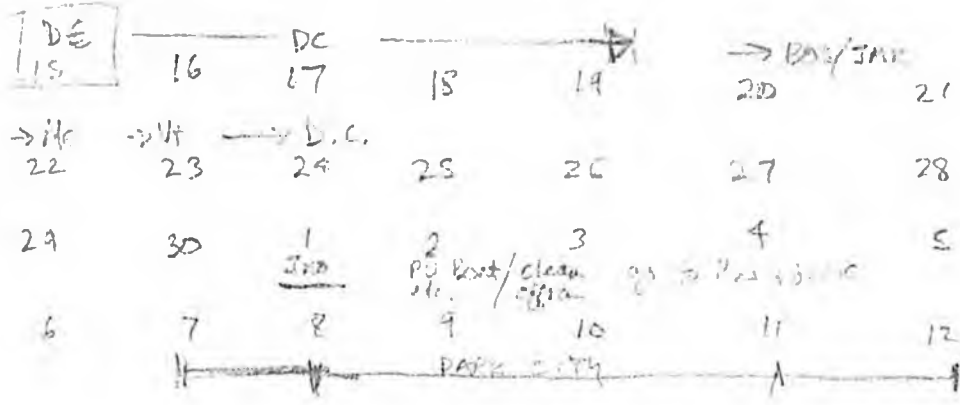


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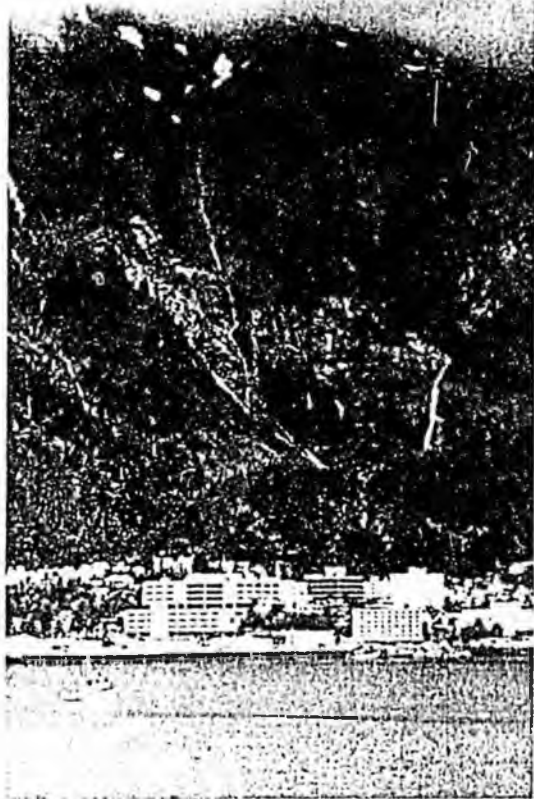
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THE FOLLOWING DOCUMENT HAS
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FILE

JUNEAU REPORT

Published by the information of Standard Alaska Production Company, Government Affairs Department



The Juneau Report is published by Standard Alaska Production Company (SAPC) Government Affairs Department to provide an overview of issues and legislation as they relate to the petroleum industry. Opinions of authors expressed here do not necessarily reflect the opinions of the company. The Juneau Report is edited by Jim Palmer. Inquiries should be directed to him or Bob Straub, SAPC Government Affairs, 564-5403 or 564-5537.

In This Issue:

- *George Nelson commentary, Page 2*

Education: Who pays . . . Local or state government

Alaska's scattered population poses equity problems

By Mike Bradner

Like many other things in Alaska during these uncertain times, Alaska's schools are also at a "crossroads." We have a number of paths we can take, each leading to different futures, and these futures may not be easy to change should we "not like" them when we get there. Despite our many problems, Alaska today probably has one of the finest school systems in the free world. It has the best paid teachers, and it also probably has the best teachers. But we are now in a time when our assets of education may be under fire — threatened by both the funding turmoil of falling revenues, and by mandated changes in "how" we fund our schools.

Certainly falling revenues require change. The political realities of "available dollars" do not exempt any state policy arena, including education. We all know about slipping oil revenues, but there is also a fundamental change brewing in the structure of funding schools — in what we call our School Foundation Act.

The changes proposed for Alaska's School Foundation Act are prompted both by unhappiness within Alaska over the division of educational funds and the equity of delivery and by the insistence of our federal overseer — the federal government. The two interests, while founded on concern for equity, may be seeking different things.

However, the essential form of this change is being

The Search For "Equity"

Funding education in Alaska is far from simple. Our complexity is not in masses of people, as might be the case elsewhere, but in our lack of "people mass." Providing a system of schools across the large landmass that is Alaska, with large urban centers contrasted by many small and isolated pockets of population, while preserving local control and education in home communities, presents an equation that really does defy cost-efficient operation. Under Alaska conditions meeting goals of educational "equity," especially goals focusing on statistical criteria, becomes complex, convoluted, and to some might often seem to result in contradictions.

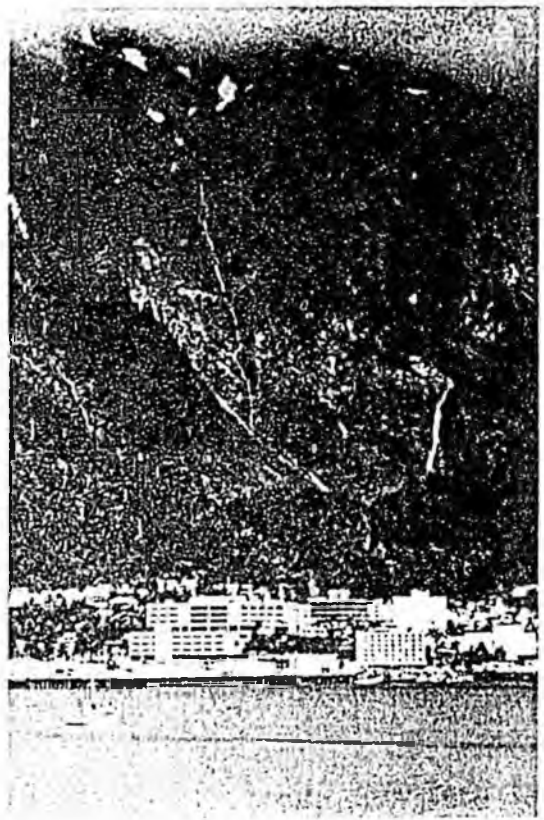
In its convoluted and contradictory twist, the new approach to equity will mean that some of us, who live in healthier tax base jurisdictions, will not be allowed to provide a more expensive education for our children, even if we can afford it.

The club behind the federalized side of reforming Alaska school funding is money. The state gets about \$70 million annually in federal PL-874 funds, which are keyed to students whose parents either work in federal tax exempt facilities or who live on federal lands. The state could lose these funds.

The "localized" concern revolves around "what" we

JUNEAU REPORT

Publication of the Alaska Department of Commerce, Community and Economic Development



The Juneau Report is published by Standard Alaska Production Company (SAPC) Government Affairs Department to provide an overview of issues and legislation as they relate to the petroleum industry. Opinions of authors expressed here do not necessarily reflect the opinions of the company. The Juneau Report is edited by Jim Palmer and Frank Baker. Inquiries should be directed to SAPC Government and Public Affairs 564-5403.

In this issue:

- *Workmen's compensation reform, Page 3*
- *"Bonding" for student loans, Page 3*

"ELF" debate intensifies

Governor, House leaders push to end drilling incentive

Hiking oil taxes to increase state budget?

To fill a state revenue "gap" created largely by a hefty increase in proposed state spending, Governor Steve Cowper and the leadership of the State House of Representatives are pushing for a tax increase on the oil industry that would raise taxes on the Prudhoe Bay oilfield.

That change is being resisted by the leadership of the State Senate, who argue that a stable taxation policy is needed now to encourage more oil development and jobs on the North Slope.

Governor Cowper and the House Democratic leadership want to change the Economic Limit Factor, an incentive formula in the State oil and gas severance tax, in a way that essentially eliminates a long-scheduled reduction in severance tax paid on Prudhoe production that took effect last year.

The ELF encourages continued production of declining, marginal wells by lowering the tax on those wells. It is widely credited, for example, for keeping marginal Cook Inlet oil platforms operating, preserving jobs and producing oil that otherwise would have been lost.

But it is also a major incentive for drilling more development wells in large fields like Prudhoe and Kuparuk on the North Slope, which results in significant additions to oil reserves. It is estimated that each new development well

Last year, the ELF incentive applied to Prudhoe for the first time since 1981, a change that had been provided for in state law. The rate of tax on Prudhoe dropped from 15% of wellhead value of the oil to about 12.5%. ELF has always applied to other oilfields in the state since it was

Continued on page 6

"ELF" issue at a glance:

- **1977:** Economic Limit Factor enacted as development incentive for oilfields, including Prudhoe Bay.
- **1981:** Prudhoe severance tax raised from 12.5% to 15%; ELF incentive denied to Prudhoe, to be reinstated in 1987.
- **1987:** Governor proposes and House passes legislation increasing severance taxes on the Prudhoe Bay and Kuparuk fields by changing the ELF formula.
- **1988:** Governor, House urge passage of ELF repeal to help finance 13% increase in State budget.

Prudhoe most productive U.S. oilfield

The Associated Press

HOUSTON — The East Texas oil field, which has been producing oil since 1930, is losing its distinction as the most prolific U.S. oil producer now that the Prudhoe Bay oil field on the North Slope of Alaska has pumped its 5 billionth barrel.

Houston-based Standard Oil Production Co., which owns 50.68 percent of the oil and 13.83 percent of the natural gas at Prudhoe Bay, said Monday the Alaska field production this month surpassed the 4.9 billion barrels of crude oil and liquid hydrocarbons pumped from East Texas.

The field, 1,300 miles from the North Pole and 250 miles north of the Arctic Circle, is the 18th largest in the world in terms of recoverable resources. It was discovered in 1968 and is estimated to be about half depleted. Although it contains an additional 13 billion barrels, technology does not now exist to remove the oil.

East Texas continues to produce oil but is

not expected to reach the 5-billion-barrel mark until next year.

The Prudhoe Bay production, over 10 years, has provided Alaska about \$23.4 billion in royalties and taxes, which Standard Oil says it the equivalent of about \$50,000 for each Alaska citizen.

The 250-square-mile Alaska field, which started producing oil into the trans-Alaskan pipeline June 20, 1977, accounts daily for about 20 percent of all oil production in the United States.

"In the face of mounting foreign imports of all kinds, the value of the oil that's been produced so far accounts for approximately \$100 billion on the plus side of this country's balance of payments' ledger," William J. Johnson, Standard Oil Production president, said.

Standard Oil Production is the wholly-owned exploration and production subsidiary of Cleveland-based Standard Oil Co. which

owns 50.68 percent of the oil and 13.83 percent of the natural gas at Prudhoe Bay. Other major owners are Exxon Corp. and Arco.

Standard said it expected the Prudhoe Bay operation would begin a natural decline of 10 to 12 percent per year beginning late next year, four years later than engineers originally thought.

"Standard Oil and its partners have successfully pushed back the onset of decline as we became more knowledgeable about the field's producing characteristics and what could be done to sustain high production rates," Johnson said. "But developing new technologies for maximum oil recovery depends to a large extent on stable oil prices and other incentives to spend the large sums of capital necessary for future development."

Oil from Prudhoe Bay averages 1.6 million barrels a day, moves through the 800-mile trans-Alaska pipeline to Valdez on the south coast of Alaska, where tankers move it to the Lower 48 states for refining.

5/13/87 WSJ p. 43

5/11/87 p 30

CREDIT RATINGS

Arco Debt Ratings On \$8.7 Billion Raised by S&P

By a WALL STREET JOURNAL Staff Reporter
NEW YORK—Standard & Poor's Corp. said it raised ratings on about \$8.7 billion of debt of Atlantic Richfield Co. and certain units.

S&P upgraded senior debt outstanding of the Los Angeles-based oil company, its Arco Pipeline Co. and Atlantic Richfield Overseas Finance N.V. units and of Sinclair Oil Co., a former unit that has been disbanded, to single-A-plus from single-A.

The rating concern also upgraded Arco's preference stock to single-A-plus

from single-A and raised ratings on commercial paper of the parent and its Arco Credit Corp. and Kupaak Transportation Capital Corp. units to A-1-plus from A-1. Senior debt outstanding of Anaconda Co., another former unit that has been disbanded, was upgraded to single-A-plus from single-A.

Despite weakened market conditions, S&P said, Arco's operating strengths in several businesses and an asset-sale program at the company help its financial prospects.

A significant reduction in Arco's debt leverage also is expected, S&P said, because of continued strong cash flow and lower capital spending, and the company could get a boost from firming oil prices. Arco's liquidity is strong, S&P said, citing cash and marketable securities of \$2.4 billion, equal to 28% of the company's debt as of the end of 1986.

* * *

NEWS

WSJ

Arco Unit to Appoint Heinze as President; Bond Retiring Early

By a WALL STREET JOURNAL Staff Reporter
LOS ANGELES—Atlantic Richfield Co. said Harold C. Heinze will be appointed president of the Arco Transportation Co. unit, succeeding Hiram E. Bond, who will take early retirement.

Mr. Heinze, 44 years old, currently is president of the Arco Alaska Inc. unit, which accounts for more than two-thirds of the Los Angeles-based parent's domestic crude oil production. He has held the position since 1983 and is credited with improving efficiencies in the Alaska unit.

Among the former heads of Arco's transportation unit is Lodwick M. Cook, now the company's chairman and chief executive officer.

Mr. Bond, 62, has headed the transportation operations since 1981. The unit operates the company's tankers and domestic pipeline interests.

Succeeding Mr. Heinze as president of the Arco Alaska unit will be William E. Wade Jr. Mr. Wade, 41, currently is Arco's vice president of corporate planning.

Separately, Arco said Mike R. Bowlin will be appointed senior vice president, international oil and gas acquisitions, a new post. The company said the 44-year-old Mr. Bowlin will assess international exploration and acquisition opportunities, suggesting that Arco is joining other U.S. oil companies interested in expanding foreign oil operations.

"Growth in the international arena is a major strategy for Arco," said Robert E. Wycoff, president of the company. Foreign locations are thought to offer better opportunities for new oil finds than U.S. acreage, which is the most thoroughly explored in the world. Mr. Bowlin currently is president of Arco Coal Co.

The appointments are effective July 1, Arco said.

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Letters from the people

The Daily News welcomes letters on issues of public interest. To accommodate as many writers as possible, letters should be limited to 250 words and accompanied by a daytime telephone number for verification. (Telephone numbers will not be printed.) Unsigned letters

will not be published; the News reserves the right to edit letters for clarity, length, taste and libel. Address letters to "Letters from the People," Anchorage Daily News, P.O. Box 14-9001, Anchorage, AK. 99514-9001.

Editor's Note: The letters on this page are additional replies to last week's People's Forum question "Should the state legislature repeal the ELF tax break?"

Issue should come to a vote

The Economic Limit Factor bill passed by the House and currently hidden in Senate committees is an important bill for Alaskans. I can't understand why our senators are afraid to bring this bill onto the Senate floor.

I personally wish to see the Senate act responsibly. Bring the ELF on the floor for debate. I support revising the ELF law which has obviously been a benefit to high oil output fields like Prudhoe Bay and a detriment to our public interests.

I hope others who share this concern will contact their senators. I am sure your senator will want to be held accountable for his or her actions.

— William D. Bobrick

Revision is a must

The public ought to demand repeal of ELF since the enactment of this legislation was designed to spur production in marginal oil fields, and works well to create billions for the industry, add hundreds of millions to state tax coffers, and provided jobs to workers and allied industries.

Having spent several years as an accountant for a major oil company I was amazed at the dealings between big oil lobbyists and our political creatures in Juneau and Washington, D.C. The accounting practices instituted in the 1979 and 1982 by our state, blessed by these legislative creatures and their masters, would require a regiment of Harvard-trained tax lawyers to clarify and untangle — the higher courts in the land may never be able to make sound decisions due to lack of wisdom. Those actions, and along with those to follow, only enrich the legal firms at the expense of the public. After all, isn't this the main purpose of most legislation?

Come on, Alaskans, let's climb out of our caves and spend a quarter or two, and throw some "push and shove" behind House Speaker Ben "Hound Dog" Grussendorf and our "lawyer" Gov. Steve Cowper on this ELF matter. Revision of the Economic Limit Factor oil tax break is a must and those who oppose it must be replaced.

Jack McCain



power to tax is the power to destroy. Unless we decide to sacrifice the oil industry on the altar of state spending, our elected officials will have to cut government back sooner or later, and they should start doing it now. Leave the ELF alone.

— Thomas K. Williams

Oil companies need profits

worth hundreds of millions of dollars to the oil companies every year. It may cost Alaska funding for schools, health care, roads and development projects but the oil companies like the ELF just the way it is. Which is why that ethereal chanting is heard throughout the capital — "stable taxation, stable taxation, stable taxation." There's nothing quite like the fervor of the converted.

— Dick Monkman

I admire the perseverance Sen. Jan Parks portrays on the ELF issue. The oil companies employ the most educated, experienced people to carry on their operations. Every little detail is exactly by law. They employ the best lawyers. Due to the high cost of drilling and the chance of a dry hole with loss of much money, they must have high profits to carry on further exploration. They are not soaking the people like some think!

— Boyd W. Haynes

Oil companies flip-flopped

The oil companies claim that the ELF tax loophole must not be closed, despite the hundreds of millions of dollars it costs the people of Alaska every year, because the industry needs "stable taxation." The phrase "stable taxation" has become the catchword of the oil lobbyists down here in Juneau. Over and over it is chanted, repeated with true religious fervor again and again and again, until the eyes begin to glaze over.

It's kind of funny to think back a few years, when Alaska had a "stable tax" for the oil industry. It was called separate accounting. We don't have it any more because these devotees of stability, the oil companies, sued the state. The lawsuit eventually was decided in Alaska's favor, but in the meantime the 1981 legislature, with a little prompting from the oil companies, changed the tax. But the oil companies didn't complain then about "unstable taxation." Probably the fact that the changes cut their tax bill substantially had something to do with the silence.

One of the little loopholes passed in 1981 was the ELF, a complicated gem of a tax formula which puts Prudhoe Bay into the "marginal field" category. This legal fiction is

Tax climate should be stable

Definitely no! The legislature made a commitment to the oil industry through ELF legislation and even though we are currently experiencing tough fiscal times this commitment must be met. To create and maintain a positive environment for doing business in Alaska we need an equitable, reasonable and stable tax climate. This represents good public policy by stimulating further oil exploration and production with incentives such as ELF.

In weighing the pros and cons of ELF it is essential that we view our dilemma in its proper perspective. The crux of the issue lies not in a projected revenue shortfall but more in state spending and particularly the size of the operating budget. Those of us in the business arena do not enjoy the luxury of budgeting beyond our income and neither should state government.

In addressing ELF the legislature will have an opportunity to blend credibility with fiscal responsibility. Let's hope good judgment prevails!

— Dale R. Lindsey
Harbor Enterprises Inc.

Don't change rules in mid-stream

The ELF, as applied to Alaska's severance tax on oil, performs as it was designed to do: It encourages continued production of marginal wells and new investment in oil field development. There has been abundant rhetoric recounting the history of Alaska's oil field taxation, and the fact that Alaska now has the highest oil taxes of any state. Additionally, Alaska's per

fund growth in our bloated state government. Revenue forecasts indicate that we can sustain \$1.6 billion spending indefinitely, yet Cowper's proposed budget is almost \$2.3 billion.

Poll after poll shows that Alaskans want government spending cut as the first means of dealing with shortfalls. I'm sick of seeing the private sector get bled to fund RATNET, power cost equalization, four times the national average of number state workers, overtime for 40-hour work weeks, multimillion-dollar Bush schools for a handful of students, 115 state employees out-earning Cowper (\$74,000), scholarships for Outside (and foreign) colleges for athletes when, on some teams, more than 70 percent fail to graduate.

— Jerry Foster

Tax stability important

Every local family or business has income and expenses which need to be budgeted. Although all of us have a multitude of expenses, most of us have several that are both long-term and significant in our total budget planning: i.e., house mortgage, auto loan, business loan, etc. On accepting any of these financial commitments we did so with an assumed fixed set of conditions. What if midway through a mortgage or auto loan, the rules were changed and significant unplanned fee(s) or payment structure was mandated? This action would cause hardships to the party involved.

This is no different from changing the ELF on the oil industry. They have a budget much like any other business or family budget, except much larger, high risk and long-term in nature. Support a stable tax position.

— Karl Privoznik

An Appraisal: Oil Shares Regain Their Allure, at Least Temporarily

ABREAST OF THE MARKET

By BEATRICE E. GARCIA

While mergers, acquisitions and speculation fueled periodic wild demand for some oil-industry stocks in the past six years, many money managers were steadily decreasing their portfolio holdings of energy issues.

That has abruptly changed, at least temporarily, thrusting the group into the market leadership. Not only are some analysts and money managers warming up to the group again, but a few market strategists are even recommending greater weight for energy stocks in diversified investment portfolios.

"We're going to see some leadership from this group," says John Connolly, a portfolio strategist at Dean Witter Reynolds Inc. in New York.

Indeed, that has already happened. According to Indata, a portfolio-monitoring service in Southport, Conn., energy stocks were the best-performing group in the stock market in the 52 weeks ended April 30, gaining nearly 49%.

And during the first four months of this year, the group rose almost 28%, an advance second only to technology stocks, which rose a little more than 36%. The figures are measures of total return, including capital appreciation and dividend reinvestment.

Gains of some individual energy issues this year are even more impressive. For instance, Atlantic Richfield has gained 54%, closing Friday at 92%.

In deciding how much money to invest in which sectors of the stock market, portfolio managers usually use the Standard & Poor's 500-stock index as a benchmark. The index rose a little more than 19% in the four months ended April 30.

About 12% of the S&P index is made up of energy stocks, including domestic and international oil producers, oil-related supply and construction company stocks as well as coal, gas and pipeline issues.

But, says William T. Kennedy, a pension-fund consultant in Atlanta, the survey of 1,500 portfolios monitored by Indata shows just 8.8% of institutional portfolios are invested in the energy sector, just slightly more than the 8.3% they had in energy at the end of last year.

"Money managers have been underweighted in the best-performing sector of the market for the past 52 weeks," says Mr. Kennedy.

After watching the price of crude oil drop below \$10 a barrel last year, few money managers were eager to make big bets on the stocks. And the Organization of Petroleum Exporting Countries agreement last fall to restrict production was greeted with a lot of skepticism by the market.

Now there is growing conviction that OPEC has been able to control production and may even be able to raise prices at its meeting late next month. The fundamentals for energy companies have stopped deteriorating and are starting slowly to improve, some analysts say.

Meanwhile, growing interest among portfolio managers in companies that benefit from a more robust economy and somewhat higher inflation has benefited energy issues along with the other commodity-based stocks.

"Frankly, I'm amazed at the strength in the oil sector. It has to be institutional buying that is pushing them up to full valuation levels," says David Dreman, a managing partner of Dreman & Embry Investment Management in New York. His concern is that many of the oil-producing and oil-service stocks are selling at "pretty high prices relative to this year's earnings."

Other analysts say that current prices for these stocks already assume higher prices for oil reserves.

But, Mr. Dreman says, OPEC's ability to raise crude prices is still a big uncertainty. He started the year with 12% of his portfolio invested in energy stocks but has reduced that portion to 9% in the past two weeks because of his concern about the outlook for the companies' earnings.

Dean Witter's Mr. Connolly is more sanguine about the group because he believes the risk in owning in oil stocks "is asymmetrical."

It wouldn't be surprising if crude oil prices decline 10% from current levels in the weeks ahead, because demand for petroleum products typically slows a bit in spring, he says. However, if oil's price rises 10%, "we could have a stampede into these stocks" because they are still under-owned by institutions, he says.

Mitzi Malevich, a money manager with IDS Advisory Group in Minneapolis, broke away from the pack last year when she started buying the shares of oil producers. Ms. Malevich added oil-service companies to her portfolios in January.

Although she realizes that it is hard to make a case for owning many of these stocks on basis of higher earnings, especially for oil drillers, she believes a stronger economy will give the issues a boost.

Friday's Market Activity

Stock prices declined in sluggish trading as investors mostly ignored news of an April unemployment drop, firmer bond prices and a higher dollar.

The Dow Jones Industrial Average fell 12.36 to 2322.30. The Standard & Poor's 500-stock index fared worse, falling 1.34 to 293.37, even though decliners on the New York Stock Exchange barely edged gainers, 832 to 739.

Despite the economic news, "there's a fair amount of jitteriness" about the directions of the dollar and interest rates, said Larry Greenwald, co-head of the equity trading desk at Sanford C. Bernstein & Co.

VOLUME SUMMARY			
Trading totals for the week ended May 8, 1987.			
	Week 1987	1987	1986
		Since January 1	
NYSE composite	906,617,310	16,488,943,208	15,623,947,433
Warrants	2,810,300	55,666,840	85,621,560
NYSE	1,046,631,280	19,287,716,590	13,133,094,263
Warrants	2,872,300	57,865,140	84,476,400
Nasdaq OTC	730,072,600	13,501,226,357	10,806,266,300
AMEX composite	63,044,610	1,495,220,040	1,390,942,465
AMEX	54,350,000	1,306,420,000	1,192,660,000

5 MAY 87

Unocal Posts

14% Drop in Net For 1st Quarter

By FREDERICK ROSE

Staff Reporter of THE WALL STREET JOURNAL

LOS ANGELES—Unocal Corp. posted a 14% drop in first-quarter earnings, citing lower prices for crude oil and natural gas.

Net income in the quarter totaled \$60.7 million, or 52 cents a share, compared with year-earlier profit of \$70.2 million, or 60 cents a share.

The latest quarter includes a \$7 million after-tax gain from the previously undisclosed sale of a 2.5% interest in the Veslefrikk Field, offshore Norway, and a \$7 million gain on a settlement relating to windfall profit tax payments for 1980.

A company spokesman said the February sale of Unocal's oil-field interest hadn't been disclosed "because it wasn't material." The holding was sold to the Swedish national oil company, Unocal officials said. Unocal currently has a 20% interest in the field.

The 1986 first-quarter profit included \$21 million from the reversal of an earlier provision for possible refunds related to natural gas sales. Unocal didn't disclose this nonrecurring item when it reported results for the quarter a year ago. That, the spokesman said, "was a management decision."

The latest-quarter profit also reflected a 36% overall tax rate, down from a rate of 55% a year earlier.

Revenue in the latest quarter fell 9.6%, to \$2.06 billion from \$2.28 billion a year earlier.

Daily production of crude oil and gas condensate averaged 241,200 barrels, off 7% from 259,400 barrels a year earlier. Natural gas production averaged 1.1 billion cubic feet a day, up 14% from 1.03 billion cubic feet a year earlier. Sales of refined petroleum products averaged 462,500 barrels a day, up 1% from 399,800 barrels a year earlier.

Separately, the Los Angeles-based oil company's chairman and chief executive officer, Fred L. Hartley, said at the annual meeting that Unocal doesn't plan further distributions of partnership units in its 95%-owned Union Exploration Partners Ltd. The master limited partnership was created in 1985 during Unocal's battle to

fend off a takeover by Mesa Petroleum Co., its chairman and chief executive, T. Boone Pickens Jr., and other investors.

In composite trading yesterday on the New York stock Exchange, Unocal closed at \$38, up 50 cents, while Union Exploration closed at \$18.75.

Unocal originally said it planned quarterly distributions of units to Unocal shareholders as part of its payout to holders. Subsequently, the company indicated that it would undertake semi-annual distributions of units. To date, it has made only one distribution, in February 1986. Last June, it suspended distributions indefinitely.

Mr. Hartley said Unocal would continue to make investments in Union Exploration Partners, suggesting that the public holding will be diminished.

Shareholders rejected a proposal by investment analyst Kurt Wulff calling for Unocal to submit for shareholder approval any so-called standstill agreements reached with large holders in the company. Such an agreement—typically requiring a holder to agree to limit stock purchases and to vote stock with management—was reached with Mesa Petroleum and Mr. Pickens when Mesa withdrew its takeover bid.

Mr. Wulff has supported measures to increase direct shareholder participation at a number of major oil companies. His proposal at Unocal was approved by about 20.2 million shares, or 19% of those voted, a strong showing for a shareholder measure opposed by company management. Unocal has about 116.4 million shares outstanding.

On another matter, the 70-year-old Mr. Hartley sidestepped a shareholder's inquiry about whether he had any plans to retire soon. Mr. Hartley, who has led Unocal for more than two decades, said, "I make myself available to the board of directors and they can make the decision any time."

ELF: Tax changes on Prudhoe Bay oil production to begin on Saturday

By CHUCK KLEESCHULTE

THE JUNEAU EMPIRE

On Saturday, the 10th anniversary of the flow of oil through the trans-Alaska oil pipeline, there will be parties on the North Slope celebrating the opening of the 800-mile-long ribbon of steel.

There also may be parties in some oil company boardrooms. For on the same day, the Alaska oil industry will see its effective tax burden from Prudhoe Bay production fall by about \$87 million for the coming year and by \$587 million over the next 13 years, based on this spring's estimates of oil prices.

That is unless Gov. Steve Cowper gets his way. Cowper continues to ponder whether to include proposed changes to the state's severance tax structure on Prudhoe Bay oil producers — the so-called economic limit factor (ELF) in the special session called for July 1. Whether he does depends in large part on whether there is a willingness to do so in the state Senate, which has in the past, opposed changes in the ELF.

By changing the ELF the state would repeal either six-year-old tax breaks or tax incentives for the oil industry — depending upon your viewpoint — tax changes that just now are going into effect. By doing so it would bring in \$110 million more than current estimates in the coming year, \$115 million in fiscal year 1989, according to the latest revenue estimates unveiled June 8 and produce the state an estimated \$1.43 billion through the turn of the century, based on computer runs done earlier this spring.

The change, while adopted by the state's House in April, is opposed adamantly on philosophical and pragmatic grounds by key members of the majority coalition in the Senate.

In recent weeks the debate over ELF has centered on whether the state needs more revenues at this time or whether oil price hikes will erase the state's budget deficit and whether Cowper by calling a special session can gain the political leverage he likely will need to prompt Senate leaders to bring the issue to the floor for a vote. Almost lost in the shuffle has been the tremendously complex debate over what the ELF change actually will do to oil development in Alaska.

ELF, while it might conjure up images of green-clad, wee people, is a severance tax concept designed to reduce the effective rate on oil wells as their productivity and thus profitability drops. ELF's original goal was to reduce taxes sufficiently to make it worth while to oil producers to continue to pump oil from marginal wells, thus continuing jobs and possibly increasing investment to get the oil out of the ground, as oil fields decline.

ELF as passed was based on the productivity of individual oil wells. The concept was that oil companies could supply data on the actual costs of producing oil from fields, the ELF being amended based on actual oil company cost experiences.

The original assumption, as yet unchanged, was that the ELF, which determines the effective tax rate that oil companies pay in severance taxes, would be nothing at 300 barrels a day or less of Alaska production and be 1, for wells producing just over 3,000 barrels of oil a day. In short, wells with an ELF near zero would get a big tax break, while wells in fields with an ELF near 1 would be considered so profitable they would get a tiny or no tax break, paying nearly the level of the state's official severance tax rate.

In 1977 the severance tax rate was 12.5 percent. But the oil industry questioned the constitutionality of a version of the state's companion corporate oil and gas tax law passed that year, claiming it was unconstitutional because it used the principle of separate accounting to compute taxes.

Under a separate accounting formula, oil taxes are based on the company's worldwide profits. The industry wanted the state to use the principle of modified apportionment, where Alaska taxes are based only upon profits generated from activities inside Alaska.

After a U.S. Supreme Court decision in 1980 that cast a long shadow on separate accounting — one erased by a later 1984 decision — lawmakers in 1981 scrubbed separate accounting and returned to the system of modified apportionment. The goal was to remove the danger that the state would lose the tax case and owe the industry \$6 billion to \$8 billion, while in many lawmakers' views producing a system that would grant a small tax break to the industry, while still assuring the state of almost

the same amount of revenue it would have had under separate accounting.

Thus lawmakers raised the nominal or official severance tax rate to 15 percent and inserted a 10-year moratorium on the ELF to keep it from being able to lower tax rates on the main Prudhoe Bay field unless production dropped dramatically below expectations — production on the main Prudhoe Bay field currently is about 1,200 barrels per well per day higher on average than what would have been needed for producers to have gained any benefit from ELF on the North Slope's main field while the moratorium was in effect.

A House tax study in 1985, however, looked at the 1981 changes and decided the state had lost not just \$300 million, but closer to \$850 million in revenues because of the revised tax system, officials in the state's Office of Management and Budget (OMB) now pegging the loss, above what would have resulted because of falling oil prices, at closer to \$1 billion through 1996.

The study prompted lawmakers both last year and this to consider changes in the state's oil tax system — one being to simply further extend the moratorium on ELF from being allowed to reduce rates. The ELF, when it goes into effect Saturday, will be about .84 for main Prudhoe Bay production, meaning the industry will receive just over a 16 percent cut in its severance tax rates overnight.

Cowper this January officially proposed extending the ELF moratorium for five more years. House lawmakers, however, proposed revamping the ELF formula, but allowing it to go into effect.

The new bill pegs ELF to the productivity of oil fields as a whole, not individual wells inside a field. Under the House proposal, now backed by Cowper, the severance tax rate on the main Sadlerochit field at Prudhoe Bay would work out to be 14.8 percent compared to the nominal rate of 15 percent, oil producers since January actually paying an effective rate of 12.6 percent. It would fall substantially for the other marginal fields on the North Slope and drop to zero for all Cook Inlet oil fields, currently paying just 1.3 percent in state taxes.

The rate for the new Endicott field, for example, will drop to .3 percent from the current 5.6 and on the Lisburne field to 3.6 percent from the current 12.25. The rate, however, will rise sharply on production from the state's second largest oil field, the North Slope's Kuparuk field, climbing to 11.7 percent from the current 8.1 percent.

House lawmakers argue that the current ELF formula obviously is flawed if its goal is to help marginal oil fields, since under the current law the 19,000-barrel-per-day Milne Point oil field, before it closed down last fall for economic reasons, was paying nearly the same tax rate as the 250,000-barrel-per-day Kuparuk field, although Kuparuk has far more volume over which to spread fixed production costs.

"The concept of the current ELF is obviously flawed if it doesn't treat Milne Point more favorably than Kuparuk. Kuparuk is not a marginal field and neither will Prudhoe Bay be economically for years," said state Rep. John Sund, D-Ketchikan, during House floor debate on the issue.

Supporters of the ELF change argue the bill actually will encourage continued production from truly marginal oil fields, while netting the state a more fair share of existing oil company profits on Alaska production.

According to an administration policy paper, the oil companies took in \$62 billion off Alaska oil between 1982-85 and netted \$16.1 billion in profits, the state getting only \$14.3 billion in taxes and royalties. The oil companies, in a rebuttal paper prepared by Standard Alaska Production Co., argue those findings are misleading.

Standard's report says that at current prices of closer to \$15 a barrel, the state's net share of production income over the next five years likely will be closer to 96 percent — part of the difference in the interpretations being the result of the state including oil company pipeline profits in its estimates, the companies excluding them.

Gregg Erickson, senior economist for Cowper's Office of Management and Budget, estimates the oil industry in the state will make \$3 billion in profit after all expenses are deducted this year, the ELF change lowering their earnings performance by just 3 percent.

"We think the amount the companies will pay is so small in comparison that it won't have any significant effect on future development expendi-

tures. The impact just won't be material," said Erickson last week.

According to a state Department of Revenue study, the new ELF should initially increase oil production slightly, before starting to discourage production between 1993 and 2005. Under the study, the change would prevent enough investment from being economic to cut state oil production by 21 million barrels, or five days' production at current rates — production that might be made up after 2005. The oil industry, however, strongly attacks the department's estimates.

ARCO Alaska, at one point this spring, pegged the production loss at far closer to 200 million barrels, an estimate the company now implies is probably too low. It now says that since added severance taxes might discourage companies from greater investments in secondary recovery methods, that the new ELF could cause the state's North Slope oil fields to shut down several years earlier than would be the case without the tax change.

"It simply stands to reason that any money you take from the industry will be money we won't have to reinvest in Alaska. And wringing additional production from North Slope fields is going to take a lot of investment," said George Nelson, president of Standard Alaska Production Co. last month.

Nelson argues that the new ELF formula will give Alaska the highest oil production tax of any state in the nation. He said the new ELF formula would peg Alaska's effective tax rate at 13.4 percent, above Louisiana's current 12.5 percent and far above Oklahoma's 7 and Texas' 4.9 percent rates. Alaska currently has an effective severance tax as a percent of value of 11.6 percent.

Dave Heatwole, vice president of ARCO Alaska, says it is bad policy for Alaska to be hiking its oil severance tax at the time that other states have been considering lowering their rates since Alaska is in competition with other states for future oil company investment dollars.

"Each time you look at drilling a new well you have to make decisions based on costs and whether the money you will earn will earn you more if invested elsewhere. The new law could hurt the state by shifting the outcome of those decisions," said Heatwole earlier this spring.

ARCO also argues that the new formula is a major change in the original concept of the ELF. Under current law, ARCO claims that there is an actual incentive for the industry to drill new wells, since additional production from marginal wells can actually decrease the company's overall tax burden. Under the new ELF that overall tax burden will rise, but just at a lower rate.

Erickson, however, said that is an advantage of the new formula since it ensures that the industry will pay some taxes on new oil production, even though the industry can still lower its average tax rate slightly by additional drilling.

The oil industry's major argument is that the new formula takes so much money away from the profitable oil fields, notably Kuparuk, that it discourages companies from making investments in technology to produce future marginal fields, such as Prudhoe Bay's known West Sak Sands.

"The industry needs to have profitable areas, like Prudhoe, to be able to generate the capital and then justify the expense of marginal field development. If you tax us because you think you need the money and we're the only game in town, the money just might not be there for future development when you really do need it," said Nelson.

The ELF debate, cluttered with complicated formulas and complex terms, from PEL's (production at the economic limit) to BOPY's (barrels of oil per year), pits lawmakers who like to battle over the economic analysis of formulas, against those who philosophically haven't delved into the formulas, but who are philosophically against changing oil taxes at a time that they want greater oil industry exploration and production investment in the state.

"Now is just not the time to discourage investment in this state," said Senate President Jan Faiks, R-Anchorage, when she assigned the ELF issue to a handful of committees for consideration.

Mary Halloran, associate director of Cowper's Division of Policy Development, however, says now is exactly the time to modify ELF. "It really is a matter of fairness. Why when every other element of the state is being expected to sacrifice should the oil industry be getting tax breaks?" she asks.

WSJ 4/16/87

IRS Estimated Alaskan Oil Producers May Owe Over \$200 Million for '84, '85

By ROBERT E. TAYLOR

Staff Reporter of THE WALL STREET JOURNAL

WASHINGTON—The Internal Revenue Service has estimated that Alaskan oil producers may owe more than \$200 million in windfall-profits taxes for 1984 and 1985, an IRS document from August shows.

The IRS has been discussing the matter with oil companies, industry spokesmen said, and the nature of the agency's review of the matter suggests the bill could rise further. The analysis of Alaskan tax payments also is leading the IRS to question whether crude oil prices were understated in California, which could lead the agency to question whether windfall-profits taxes were adequate for that state.

In an Aug. 20 document obtained by The Wall Street Journal, the agency said, "potential tax deficiencies in excess of \$200 million remain which to date have not been resolved" for Alaskan windfall taxes for the two years. The document, which is unusual in disclosing an IRS estimate of taxes owed, solicited expert witnesses to

help in negotiations or litigation with the oil companies.

The statement comes three years after IRS officials told congressional auditors that they probably would seek "substantial" added windfall tax from Alaskan producers. The \$200 million figure was the most specific IRS estimate to surface of the amount it may seek for 1984 and 1985.

Neither the agency nor the companies would comment on the issue of windfall-profits taxes.

California oil prices are involved because they are used to calculate the Alaskan oil's value. The Alaskan crude's well-head price, which is used in determining the windfall tax, generally is determined by subtracting transportation costs from the price of the oil when it lands in California.

The IRS document shows that it is assigning consultants to study whether oil companies overstated the cost of transporting oil to the lower 48 states, mainly California. It also has them assessing whether oil companies have kept crude oil prices in California below market levels for tax advantages, according to Gary Taylor, founder of Incentives Research Inc., Los Angeles, one of the firms hired for expert help.

Atlantic Richfield Co. is probably most vulnerable to any IRS claims. Of 16 oil companies that produce Alaskan oil, the bulk of production is by Arco, Exxon Corp. and British Petroleum Co.'s Standard Oil Co. unit. And Arco priced its Alaskan oil lower than the other two, according to Mr. Taylor and a Federal Trade Commission analysis.

Standard Oil already has reported paying \$197 million to resolve Alaskan windfall-tax claims for 1980 through 1983. Arco and Exxon spokesmen said they have set up reserves to cover several matters, and would include any windfall-tax deficiencies.

According to Mr. Taylor, one reason the IRS needs analysis of California pricing is to rebut Arco's defense that its Alaskan oil prices were comparable to California prices after considering shipping costs.

So far, Mr. Taylor said in an interview, the IRS has asked his firm to review California crude pricing only as it influenced the value of Alaskan oil. But if the IRS challenges California pricing in Alaskan tax proceedings, it could also question whether adequate taxes were paid on oil in California. "The IRS would have a decision to make at that point," said Mr. Taylor.

California's volume of oil production—roughly two-thirds that of Alaska—suggests that any deficiency finding on California oil could be substantial.

Rate	3.50
7 1/2%	3.47
8 1/2%	3.51
9 1/2%	3.50
10 1/2%	3.51
11 1/2%	3.51
12 1/2%	3.55
13 1/2%	3.56
14 1/2%	3.51
15 1/2%	3.68
16 1/2%	3.50
17 1/2%	3.71
18 1/2%	3.61
19 1/2%	3.59
20 1/2%	3.77
21 1/2%	3.68
22 1/2%	3.69
23 1/2%	3.66
24 1/2%	3.60
25 1/2%	3.72
26 1/2%	3.79
27 1/2%	3.80
28 1/2%	3.98
29 1/2%	3.86
30 1/2%	3.95
31 1/2%	3.97
32 1/2%	3.94
33 1/2%	3.92
34 1/2%	3.99
35 1/2%	3.11
36 1/2%	3.01
37 1/2%	3.12
38 1/2%	3.04
39 1/2%	3.01
40 1/2%	3.06
41 1/2%	3.06
42 1/2%	3.08
43 1/2%	3.10
44 1/2%	3.14
45 1/2%	3.14
46 1/2%	3.24
47 1/2%	3.23
48 1/2%	3.43
49 1/2%	3.43
50 1/2%	3.43
51 1/2%	3.12
52 1/2%	3.17
53 1/2%	3.17
54 1/2%	3.44
55 1/2%	3.17
56 1/2%	3.16
57 1/2%	3.17
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93 1/2%	3.17
94 1/2%	3.16
95 1/2%	3.17
96 1/2%	3.16
97 1/2%	3.17
98 1/2%	3.16
99 1/2%	3.17
100 1/2%	3.16

Mr. Taylor, the IRS consultant, said integrated oil companies' incentive to minimize the price of their North Slope oil stemmed from taxes and royalties that once took 92% of the Prudhoe Bay price. That created an incentive to take profits instead in lower-taxed transportation, refining or marketing operations.

In fact, a U.S. Energy Department report last spring found that refiner profit margins were considerably higher in California in 1984 and 1985, and crude prices were unaccountably lower, than in the rest of the nation.

Mr. Taylor is no stranger to the subject. For nine years, he has advised California and the city of Long Beach in their lawsuits charging eight oil companies underpaid royalties by underpricing California crude oil. The suits charge the companies used their control over about two-thirds of the state's pipeline capacity to hold down the price of crude oil.

The more recent of the two suits, awaiting trial in a California state court, lists as defendants Exxon, Chevron Corp., Unocal Corp., Mobil Oil Corp., Texaco Inc., and Royal Dutch/Shell Group's Shell Oil Co. affiliate and one of its subsidiaries. A federal judge's dismissal of a prior suit against them is under appeal. Both the IRS and the Justice Department's antitrust division have been monitoring the California suits. The companies deny the charges.

Alaska Disputes Land Swap

By a WALL STREET JOURNAL Staff Reporter

WASHINGTON — Alaska contends the Interior Department's planned land exchange in that state would trade away at a depressed price the most promising portion of the Arctic National Wildlife Refuge.

At issue is the agency's tentative accord to trade mineral rights on portions of the refuge to Alaskan native corporations and their oil-industry partners. In exchange, the agency would receive native lands elsewhere in Alaska with valuable wildlife habitats.

In a study circulated here, Alaska said its analysis shows that the agency proposes to trade away the tops of all the preserve's most promising geologic structures for oil and gas. That contradicts the department's claim that only 34 of the trade's 73 refuge tracts lie over identified structures that could contain oil and gas.

The state also called it "almost certain" that the federal government would generate "substantially higher revenues" if it held a competitive lease sale for the refuge's lands instead of trading them.

Susan Reece, deputy assistant secretary of the interior, defended her agency's valuations and geological analysis. The department has said it won't complete the trade without congressional approval.

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Earnings Rise At Six Major Oil Companies

Most of the Gains Reported
For 3rd Period Reflected
Rebound in Prices of Oil

A WALL STREET JOURNAL News Roundup

Six major oil companies reported third-quarter earnings, with most posting profit increases based on the rebound in oil prices from depressed year-earlier levels. Crude-oil prices hit an 11-year low near \$10 a barrel in July 1986, but have averaged at least \$6 a barrel more in the third quarter this year than in the like period last year.

Companies heavily involved in refining and marketing generally showed smaller gains, as those "downstream" operations have had smaller profit margins lately. Chemical-producing subsidiaries showed strong earnings.

Earnings for the quarter more than tripled at the Shell Oil Co. unit of Royal Dutch/Shell Group and at Atlantic Richfield Co., but there were more-modest gains at most big, integrated companies. Net income rose 1% at Exxon Corp., 18% at Occidental Petroleum Corp. and 33% at Unocal Corp. Mobil Corp.'s earnings were up 75%, but profit from its petroleum operations declined 12% for the quarter.

Atlantic Richfield Co.

Los Angeles-based Arco's third-quarter sales jumped 24% to \$4.40 billion from \$3.53 billion.

Arco's chairman, Lodwick M. Cook, said the surge in earnings showed the impact of higher crude prices on oil and gas operations, a strong performance by the Arco Chemical Co. unit, and higher crude and natural gas liquids production. He said lower refining and marketing earnings, reflecting "significantly lower" margins for petroleum products, partly offset the increases.

Earnings from Arco's world-wide oil and gas exploration and production rose to \$235 million from \$41 million in the year-earlier three months. Arco produced more oil at its Alaskan North Slope operations, though production was lower in the rest of the U.S. The refining and marketing business reported earnings of \$30 million, down from \$94 million in the 1986 quarter.

In the first nine months this year, Arco's net soared 60% to \$884 million, or \$4.82 a share, from \$551 million, or \$3.03 a share, a year earlier. Sales rose 7.7% to \$12.24 billion from \$11.37 billion.

Exxon Corp.

Exxon's scant 1% third-quarter earnings increase reflected a standoff that was characteristic of the whole industry: Improved results in exploration and production counterbalanced by poor results in refining and marketing.

Revenue rose 27% to \$21.9 billion from \$17.2 billion in last year's third quarter. The company's profit margin for the quarter slipped to 4.9%, compared with 6.1% in the 1986 period.

L.G. Rawl, Exxon's chairman, said crude-oil prices averaged \$6.50 a barrel more in this year's third period than in the year-earlier period. That helped earnings at the company's exploration and production divisions, which had profit of \$933 million, up \$391 million from the third quarter of 1986.

But the refining and marketing side posted only a \$60 million profit, down from \$463 million in the 1986 quarter. The New York-based company said margins were "squeezed by a combination of higher crude prices and marketplace pressures." Mr. Rawl called the refining and marketing results "below acceptable levels."

Of the \$60 million in refining profit, only

THIRD-QUARTER NET INCOME

	1987		1986		% chg.
	in millions	per share	in millions	per share	
Arco	315	1.71	102	0.55	+209
Exxon	1,063	0.75	1,035	0.73	+1
Mobil	319	0.77	182	0.45	+75
Occidental	420	0.20	39	0.12	+18
Shell	29	0.25	133	e	+216
Unocal	29	0.25	22	0.19	+33

	1987		1986		% chg.
	in millions	per share	in millions	per share	
Arco	884	4.82	551	3.03	+60
Exxon	2,785	2.31	3,880	2.68	-15
Mobil	875	2.13	1,204	2.95	-27
Occidental	202	0.90	161	0.69	+33
Shell	795	e	628	e	+26
Unocal	15	1.30	127	1.09	+20

\$7 million came from U.S. operations, down sharply from \$106 million in the third quarter of 1986. Foreign refining and marketing operations chipped in \$53 million of earnings for the quarter, down from \$357 million in the 1986 quarter.

Chemical operations contributed earnings of \$152 million, up \$38 million, or 33%, from the like quarter last year.

The company stepped up capital and exploration spending to \$1.98 billion in the quarter, a rise of \$451 million from last year's third quarter, mainly because of increased activity in Australia.

The company declined to discuss possible steps to improve profitability in the refining and marketing operations. Brian Jacoboski, an oil analyst at Paine Webber Inc., said Exxon has been rumored to be discussing the sale of its European refining operations to Saudi Arabian interests, and he believes the rumor is true.

An Exxon spokeswoman yesterday declined to confirm or deny the report. She said the company doesn't comment on "rumors of acquisitions, mergers, or divestments."

In the first nine months this year, revenue was \$61.5 billion, up 7% from last year's figure of \$57.4 billion.

Mobil Corp.

While New York-based Mobil reported a 75% earnings gain for the third quarter, year-earlier amounts are adjusted for a loss on the sale of its Container Corp. of America subsidiary. Before the adjustment, third-quarter earnings show a 4% decline.

In the 1986 third quarter, Mobil took a \$150 million loss on the Container Corp. sale. Without that loss, third-quarter earnings in 1986 would have been \$332 million.

Revenue was \$14.4 billion, up 27% from \$11.3 billion in the 1986 quarter.

Overall, Mobil's chairman, Allen E. Murray, said petroleum earnings declined 12% in the third quarter, to \$397 million from \$453 million a year earlier.

The exploration and production segments were strong, producing profit of \$326 million world-wide, compared with \$130 million in last year's third quarter.

But refining and marketing earnings plunged to \$71 million from \$323 million in the year-earlier period.

Mobil's chemical operations showed \$92 million in profit for the quarter, a record and a 142% increase from the 1986 third quarter. Mobil's retailing unit, Montgomery Ward, reported profit for the September quarter of \$21 million, up \$8 million from the like period last year.

Capital expenditures, including oil-exploration outlays, rose 22% in the third quarter to \$828 million from \$681 million last year. But in the nine-month period, they were down 5% to \$2.09 billion from \$2.19 billion.

For the first nine months, Mobil reported revenue of \$47.8 billion, up 9% from \$37.4 billion in the 1986 period.

Occidental Petroleum Corp.

For Occidental, a redemption of preferred shares reduced preferred dividend requirements and accounted for the relatively sharp third-quarter per-share net rise. Sales were \$4.22 billion, up 14% from \$3.72 billion.

Arnold Hamner, chairman, said Los Angeles-based Occidental's oil and gas division had \$58 million of pretax earnings, compared with a loss of \$3 million in the 1986 period. Higher crude prices accounted for the oil and gas rise in earnings, al-

though declining natural gas prices offset some of that increase. He said higher domestic natural gas production and natural gas liquids sales also contributed to the increase.

The natural gas transmission business had pretax earnings of \$17 million in the quarter, down from \$68 million last year, reflecting Occidental's sale last June of United Gas Pipe Line Co., higher depreciation expense and lower sales volume.

Occidental's chemical business had income of \$49 million, up from \$26 million in the year-earlier quarter. It recorded higher sales for its electrochemicals, detergent and specialty products, and for polymers and plastics, and had higher margins for its olefins and agricultural products, Occidental said.

Occidental's 1986 quarter included a \$106 million gain on the sale of stock. It said its tax rate in the latest quarter was lower, reflecting the reduction of its ownership of the IBP Inc. meatpacking unit to 51%.

In the nine months, sales rose 14% to \$12.7 billion from \$11.2 billion.

Shell Oil Co.

Houston-based Shell reported that third-quarter net more than tripled, largely because of the increase in crude-oil prices and a record profit from chemical earnings. Revenue rose 40% to \$5.65 billion from \$4.01 billion.

But like other major integrated oil companies, Shell's refining and marketing operations were hurt, as oil-product earnings declined 13% to \$68 million. Refining and marketing operations for most major U.S. oil companies were hurt in the third quarter because competitive pricing didn't allow product prices to keep pace with the rise in crude prices.

That rise in crude prices, however, provided a big lift to exploration and production, or "upstream," earnings. Shell's upstream profit in the quarter surged to \$262 million from \$25 million. Shell said domestic crude prices averaged nearly \$17 a barrel in the quarter, up about \$6 from a year earlier, which, combined with lower production costs, boosted profit. A 5% decline in natural gas prices somewhat impaired earnings.

Petrochemical operations were standouts for most major oil companies in the quarter because of strong demand and improved margins, and Shell was no exception. The company said chemical-product earnings rose nearly 150% to a record \$131 million.

