ALASKA LEGISLATURE COMMITTEE FILES 1987-1988 8672
4946 HRES HB 164 (FILE 2) (see ELF) 518

year	psl price	----- barrel per day chunks	volume	wells	elf	sev tax	per bbl sev tax	royalty	total rev	disc rev
1988	10.00	156	569.4	631	0.820	613	1.08	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		2559	4807	4319

table 2
kuparuk - base case

year	psl price	10000 barrel per day chunks	volume	wells	elf	sev tax	per bbl sev tax	royalty	total rev	disc rev
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	135	107
						201		421	623	561

table 3
prudhoe bay - 5 chunks

year	psl price	10000 barrel per day chunks	volume	wells	elf	sev tax	per bbl sev tax	royalty	total rev	disc rev
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	psl price	10000 barrel per day chunks	volume	wells	elf	sev tax	per bbl sev tax	royalty	total rev	disc rev
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: CSHB 164(Fin) am
PUBLISH DATE:

FISCAL NOTE

REQUEST:

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

Agency Affected:
BRU:
Components:

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING						
CAPITAL						
REVENUE	187,410	227,630	280,260	272,570	248,510	216,540

FUNDING: (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER						
TOTAL						

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

(See Attached)

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

Approved by Commissioner: Hugh Malone VW FOR
Agency: Revenue
Date: 3/8/88

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 amont 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	Thomson	Seal	Niakuk	North Slope
1988	133.57	59.56	0	0	-6.02	0	0	0	0	137.4
1989	161.97	72.11	0	0	-6.45	0	0	0	0	227.63
1990	291.28	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	-8.86	-25.03	274.9
2004	353.23	-.08	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	2045.52

Change in Tax rate

Year	Prudhoe	Kuparuk	Milne	Endicott	Lisburne	West Sak	Thomson	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	-.08736
1996	.02487	.071445	0	-.018285	-.02766	0	-.0317275	0	-.089505
1997	.02487	.071445	0	-.018285	-.02766	0	-.03095575	0	-.089565
1998	.02487	.071445	0	-.018285	-.02766	0	-.03717	0	-.089205
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

STATE OF ALASKA 1987 LEGISLATIVE SESSION — No. 3

FISCAL NOTE

REQUEST

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

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

EXPENDITURES/REVENUES: (Millions of Dollars)

OPERATING	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
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: Vincent Wright for Chuck Logsdon — Phone: 276-5364
Division: Office of the Commissioner — Date: 3/19/87

Approved by Commissioner: Malone — Date: 3/19/87
Agency: Revenue

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Distribution (by Agency preparing fiscal note):
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- Senate Secretary

Page ____ of ____

- ARCO Alaska, Inc.
Media Communications
Post Office Box 100360
Anchorage, Alaska 99510-0360

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for release IMMEDIATELY

For further information contact
Susan Andrews at (907) 265-6847

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 Wa[illegible]

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 Anchor ge 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 [illegible] Kuparuk field.

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

-more-

"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.

####

A-11-88
(rls 50)

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 future and it could be significant to the company."

Associated Press file photo

George M. Miller

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 b. West Sak.
2 b. ANWR

oilprof.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.

WALL STREET JOURNAL
April 30, 1987
Page 6

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.

WALL STREET JOURNAL
APRIL 24 1987 p.7

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 in millions	1987 per share	1986 in millions	1986 per share	% chg.
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[illegible] 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 increases.

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

But Lodwrick 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 $)

	STANDARD	ARCO	CONOCO	TOTAL
Alaska	$1,271.3	$ 79.3	n/a	$1,351.3
Alabama	5.4	0.6	-	6.0
Arizona	8.4	0.4-	-	8.8
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	2.8	15.4	0.1	18.3
Georgia	57.2	16.2	0.1	73.5
Hawaii	0.8	-	-	0.8
Idaho	79.4	0.3	5.0	84.7
Illinois	79.4	46.2	0.4	126.0
Indiana	1.8	45.1	1.0	47.9
Iowa	1.6	30.7	1.3	33.6
Kansas	9.0	75.2	-	84.2
Kentucky	2.4	9.4	0.5	12.3
Louisiana	115.0	23.7	0.9	147.6
Maine	5.6	0.2	0.1	5.9
Maryland	28.0	2.4	0.1	30.5
Massachusetts	15.1	35.2	0.2	50.5
Michigan	8.0	57.3	0.4	65.7
Minnesota	43.5	16.9	0.1	60.5
Mississippi	1.8	0.6	-	2.4
Missouri	23.0	30.0	0.1	53.1
Montana	2.4	0.6	-	3.0
Nebraska	68.9	1.0	-	69.9
Nevada	2.3	5.4	-	7.7
New Hampshire	0.2	0.1	-	0.3
New Jersey	9.5	32.6	-	42.1
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	1.8	2.5	-	4.3
Ohio	15.4	67.3	0.6	83.3
Oklahoma	246.7	192.6	3.5	442.8
Oregon	18.9	99.1	10.0	128.0
Pensylvania	25.2	150.0	0.3	175.5
Rhode Island	0.3	0.15	0.2	0.6
South Carolina	2.9	0.1	0.2	3.2
South Dakota	0.1	0.5	-	0.6
Tennessee	0.6	1.25	-	1.8
Texas	2,339.8	1,114.8	21.3	3,475.9
Utah	6.4	139.1	1.0	146.5
Vermont	1.0	0.3	-	1.3
Virginia	1.6	0.6	0.1	2.3
Washington	211.6	506.3	47.5	764.8
West Virginia	0.1	0.15	-	0.21
Wisconsin	8.9	173.6	0.5	183.0
Wyoming	12.5	1.5	-	14.0
TOTAL COSTS	$6,745.0	$3,669.6	124.1	$10,536.2

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.

ARCO : 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, 1983--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.

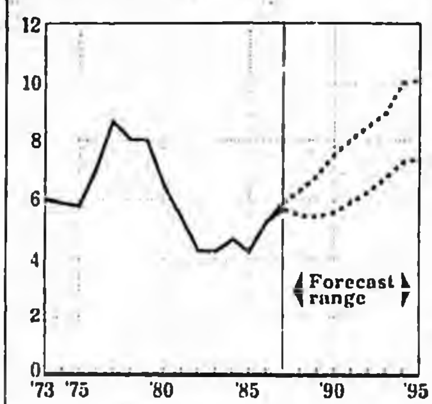
Currently stirring controversy is a proposal by Senate Finance Chairman Lloyd Bentsen (D., Texas). He recently got his committee to amend the pending trade bill to require the president to do whatever is necessary to keep oil imports from exceeding 50% of the U.S. supply, subject to congressional veto. 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, reluctantly 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.

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.

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 disruptions 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.

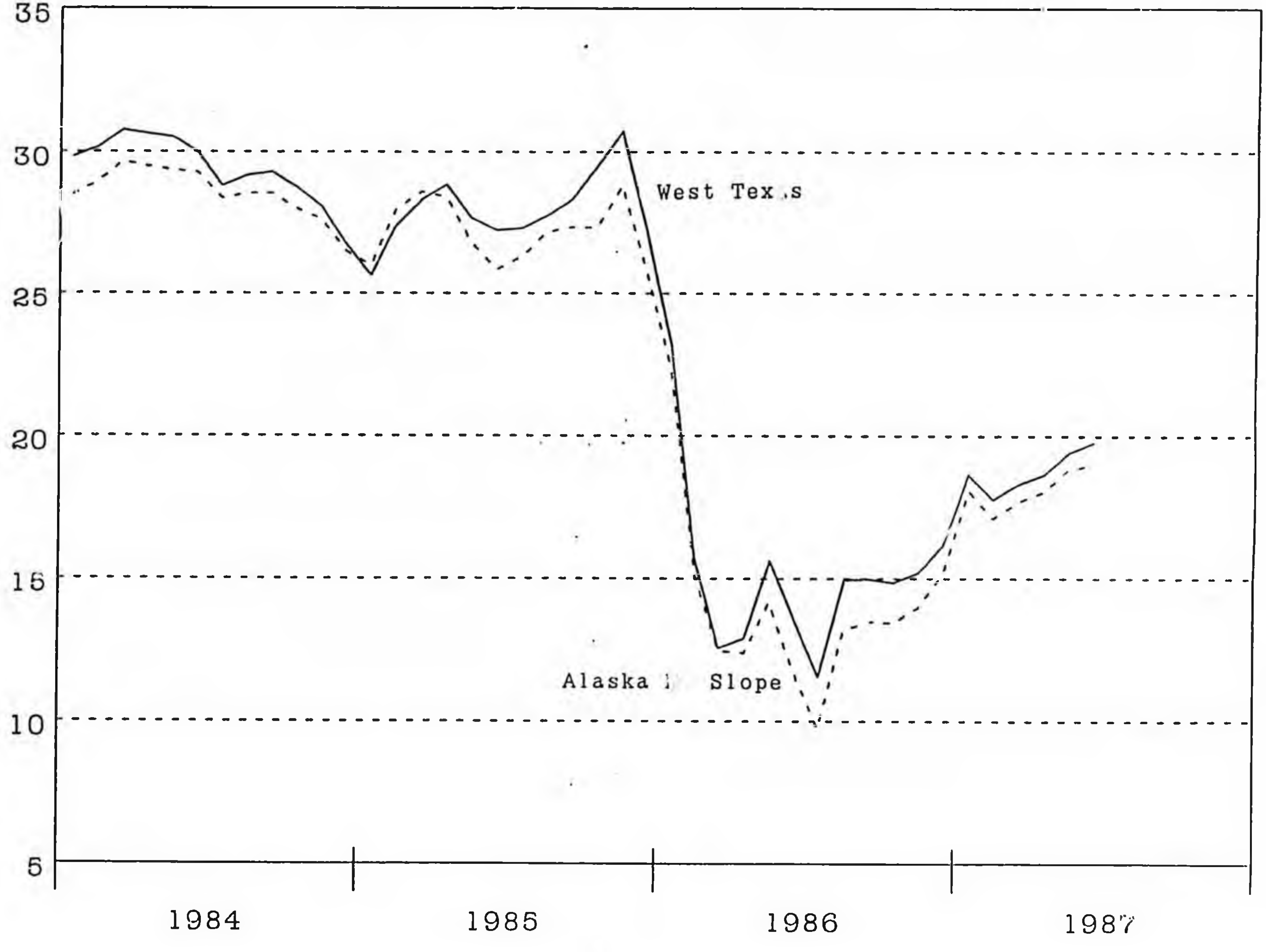
Harvard professor William Hogan argues that the benefits of a $10-a-barrel fee actually would exceed its costs. But the Energy Department doesn't buy Mr. Hogan's view. Neither does Robert Fri, president of Resources for the Future and a former head of the Energy Research and Development Administration, 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."

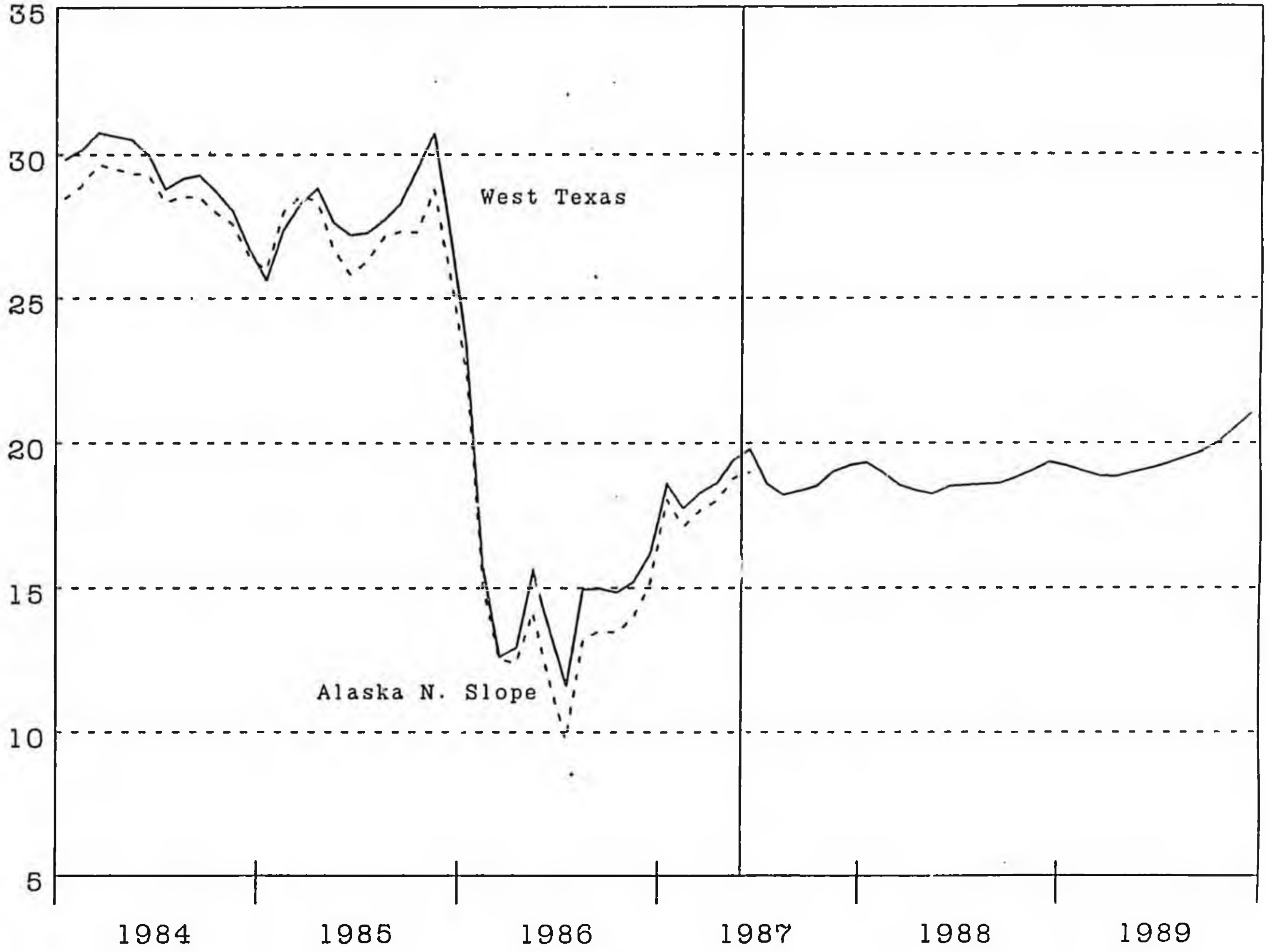
West Texas Intermediate Spot vs
Alaska N. Slope at the Gulf Coast
(Dollars per Barrel)



Oil Price Forecast Comparison
West Texas Intermediate Spot Market Price
(U.S. Dollars per Barrel)

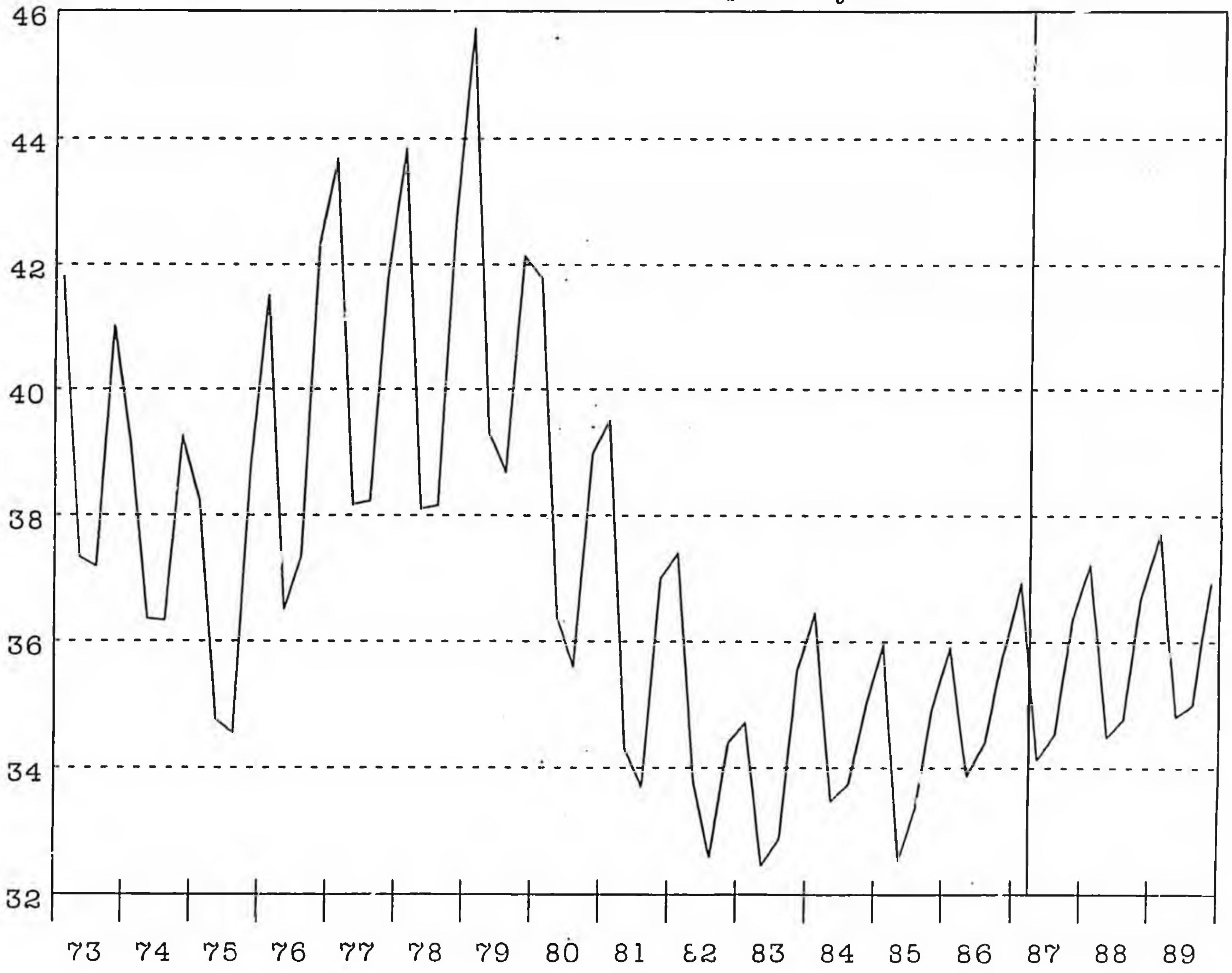
Forecast Prepared	Year 1986	1987	1988	1989
June 1, 1987	$15.12	$18.55	$18.73	$19.50
November 1, 1986	$15.15	$17.58	$18.46	$19.42
May 1, 1986	$16.20	$17.22	$18.24	$19.35

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

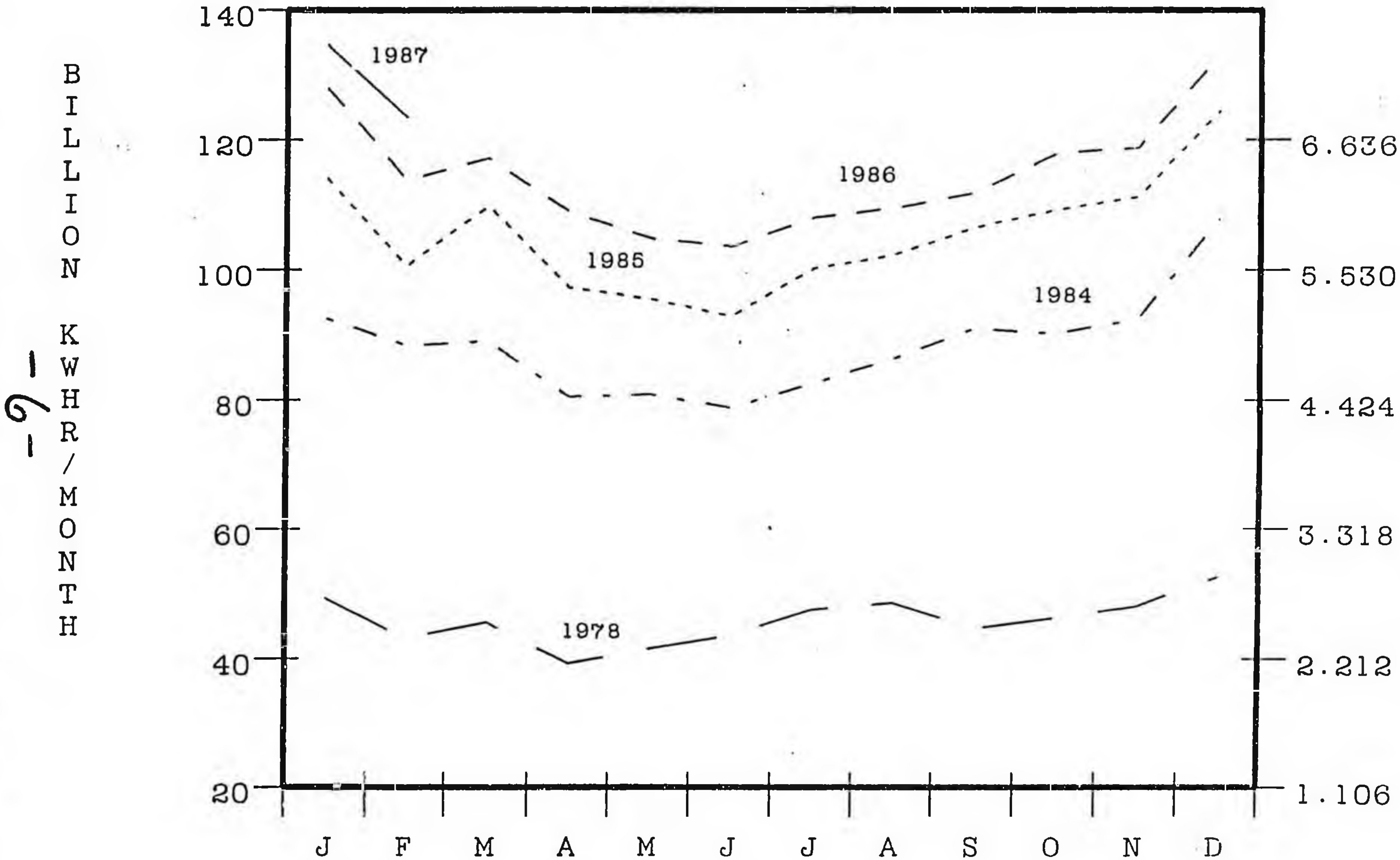


Seasonally Adjusted Oil Consumption
For the Major 7 Developed Countries
(Million Barrels per Day)

Developed Country Oil Consumption
(Million Barrels per Day)

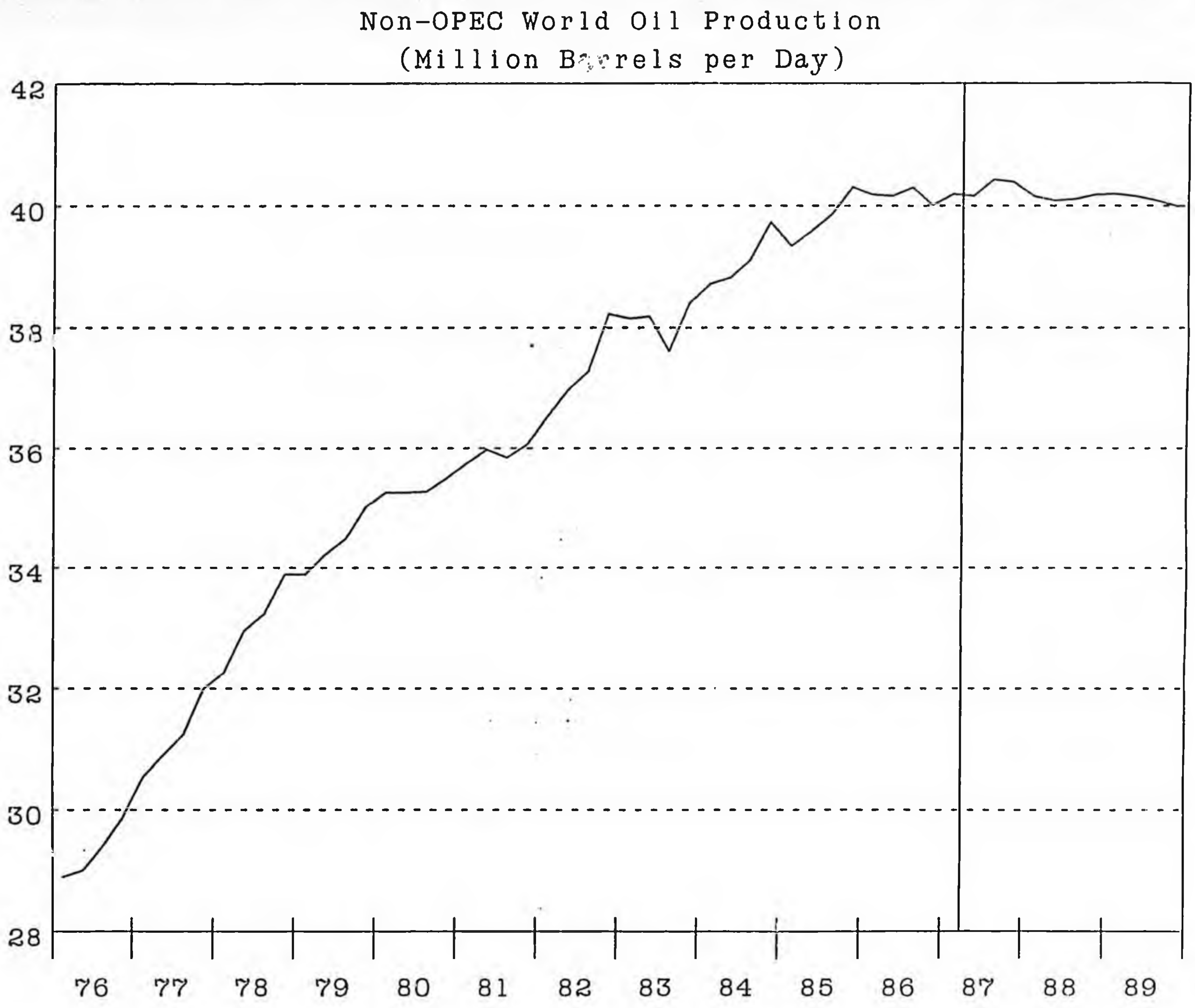


MONTHLY NUCLEAR ELECTRICITY GENERATION
NON-COM COUNTRIES



SRC: U.S. DOE MONTHLY ENERGY REVIEW

Developed Country Commercial Oil Inventories
(Million Barrels)



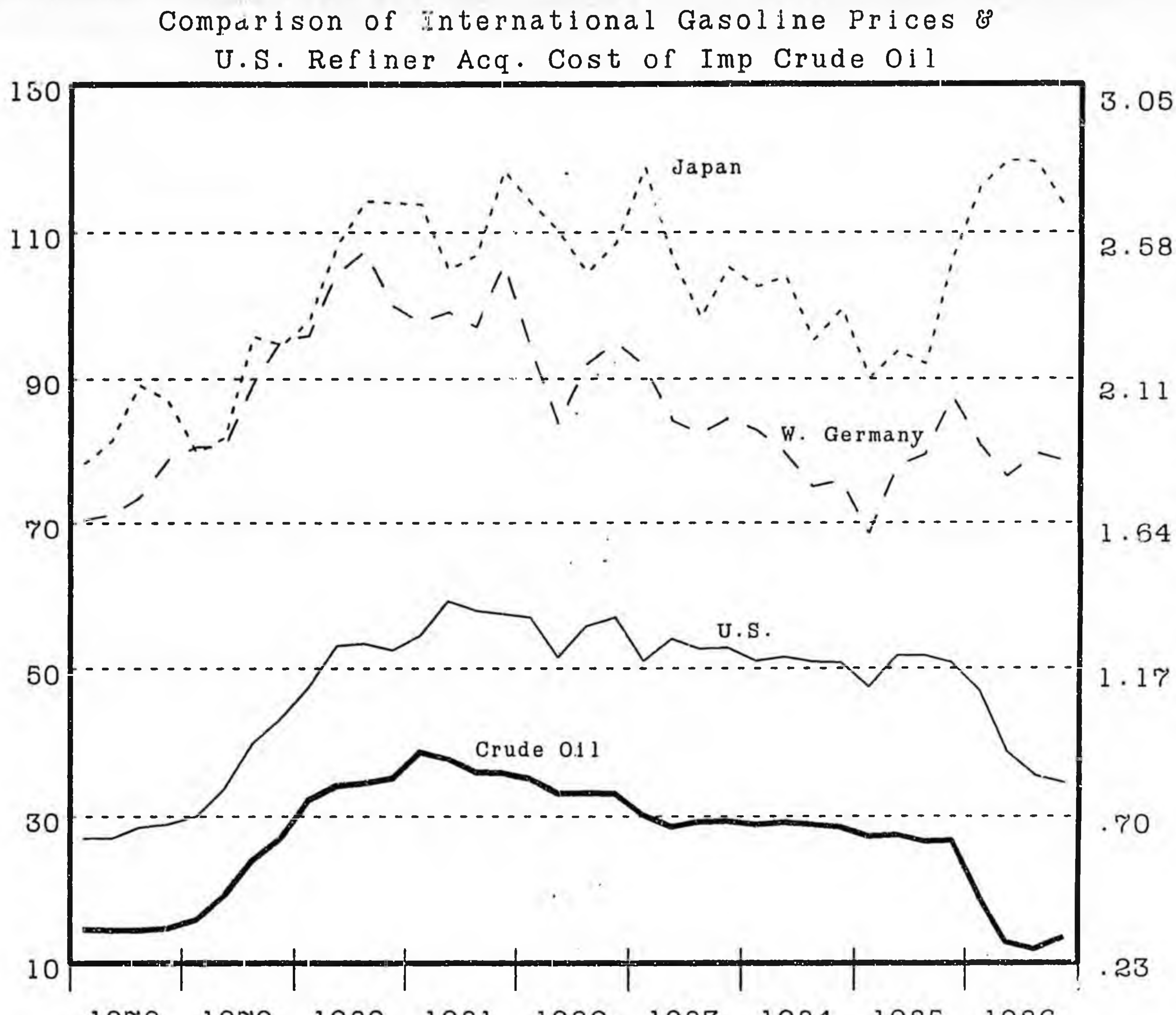
Non-OPEC World Oil Production
(Million Barrels per Day)
42
40
38
36
34
32
30
28
76
77
78
79
80
81
82
83
84
85
86
87
88
89

- 8 -

OPEC Crude Oil Production
(Million Barrels per Day)

OPEC Gross Revenue
(Million Dollars per Day)

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


Comparison of International Gasoline Prices &
U.S. Refiner Acq. Cost of Imp Crude Oil
Japan
W. Germany
U.S.
Crude Oil
130
110
90
70
50
30
10
3.05
2.58
2.11
1.64
1.17
.70
.23
1978
1979
1980
1981
1982
1983
1984
1985
1986

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

Co..pliments 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 ind 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 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 ofthe 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.

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

<u>A Model to Evaluate the Economics of Drilling Additional Wells</u>

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 thing 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

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

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 591 and Kuparuk 305 (adjusted for non-producing days).

x = 3 is determined such that

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

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.

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

This coefficient calibrates f(w) such that as w = T (i.e. the number of wells is doubled), a_B 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 inputed (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.)

Price	Additional Wells Prudhoe	Additional Wells Kuparuk
$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 PS1 price for Prudhoe Bay.

Table 2 compares the well count and production volume between optimized in-fill drilling programs at $15 and $20 at PS1 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 thing 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 PS1 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 PS1 Price

	No Optimization		Optimization (49 wells)		Increased	Increased
	Wells	Volume (mmbbl)	Wells	Volume (mmbbl)	Wells	Volume (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

	$15 (49 wells)		$20 (155 wells)		Increased	Increased
	Wells	Volume (mmbbl)	Wells	Volume (mmbbl)	Wells	Volume (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

	No Optimization		Optimization (33 wells)		Increased	Increased
	Wells	Volume (mmbbl)	Wells	Volume (mmbbl)	Wells	Volume (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

	$15 (33 wells) Wells	Volume (mmbbl)	$20 (103 wells) Wells	Volume (mmbbl)	Increased Wells	Increased Volume (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 percent

and subsequently the relative significance of Effect V is 81 perecent. This implies that 19 percent of the drilling at Prudhoe Bay would be accruable 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 PS1 price, are as follows.

	Additional Wells	
Price	Prudhoe	Kuparuk
$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

Roger Marks, State of Alaska, Dept. of Revenue
J. William Moore, State of Alaska, Dept. of Revenue

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 Sak, 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_oth 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_{tc} = transportation cost and quality differential to bring the Prudhoe Bay wellhead price back to the specific field's wellhead, dollars per barrel,
E'_{tc} = 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_{sIT} = state corporate income tax rate, percentage expressed as decimal, and
i_{fIT} = 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

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

where E_{tc} 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_{tc}. E'_{tc} 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

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

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

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

where

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

and

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

There is a floor of 300 B/D [48 m^3/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 [$5.03/m^3] (nominal) for the $i_{ST}[P-E_{tc}+(i_{RR}C_f)]$ 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

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

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

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

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

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

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

Schedule Inputs					Single Value Inputs	
t_o (year)*	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_{tc}	2.56
3	23.30	0	0	341	E'_{tc}	1.29
4	23.40	0	0	341	C_f	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_{fix}	0.1
8	23.80	19	45	0	C_{var}	0.9
9	23.90	19	45	0	ΔN_{pp}	26
10	24.00	19	45	0	E_{oF}	0.33
11	24.10	19	45	0	E_{ov}	0.67
12	24.20	19	45	0	E_{oEP}	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_{sIT}	0.014
16	24.60	7	28	0	i_{fIT}	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

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

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

$$I_{fT}=I_{NRf}-D_{df}.$$

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

$$E_{fIT}=i_{fIT}I_{fT}.$$

Discounted federal income tax is expressed by

$$E_{fITPV}=E_{fIT}[(F_D)_{n_o}].$$

TABLE 2—FIELD XXX ECONOMIC RENT

t (years)	p (dollars/bbl)	ΔN_p (10^6 bbl)	ΔN_{pPV} (10^6 bbl)	I_g ($1 million)	I_R ($1 million)	I_{RPV} ($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_{RT} ($1 million)	E_{RTPV} ($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	382	261	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	456	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	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	8	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	78	8	2	2	0	0	0	20	4	3	1	1
21	25.66	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	245	299	139	1,047	760	679	265	119	55	100

TABLE 2—FIELD XXX ECONOMIC RENT (continued)

I_{NR1} ($1 million)	D_{r1} ($1 million)	D_{d1} ($1 million)	I_{ST} ($1 million)	E_{ST} ($1 million)	E_{STPV} ($1 million)	I_{NR} ($1 million)	E_{WPT} ($ million)	E_{WPTPV} ($1 million)	C_{IOC} %	D_R ($1 million)	D_{dl} ($1 million)	I_{IT} ($1 million)	E_{RT} ($1 million)	E_{RTPV} ($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	69	37
323.6	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	36
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	585	199

	C_{ee}, dollars/bbl
C	8.07
E_o	2.81
E_{IC}	1.29
E_R	2.62
I_{ST}	1.47
E_{PT}	0.58
E_{ST}	0.12
E_{RT}	2.11
E_{WPT}	0.00
Total	19.07
P_{ee}	24.80
E_r	5.73
E_n, $1 million	539.53
I_{AB}, $1 million	34.00

TABLE 3—FIELD XXX LOW-PRICE VECTOR

t (years)	P (dollars/bbl)	ΔN_R (10^6 bbl)	ΔN_{RPV} (10^6 bbl)	I_g ($1 million)	i_R ($1 million)	i_{RPV} ($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_{RT} ($1 million)	E_{RTPV} ($1 million)	D_r ($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	6	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	26	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	6	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	26	10	0	0	45	18	6	3	9
13	18.99	14	5	266	28	10	16	6	0	0	37	14	6	2	7
14	19.17	11	4	211	22	7	12	4	0	0	33	11	5	2	5
15	19.36	9	3	174	18	6	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	65	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_{NRs} ($1 million)	D_{rs} ($1 million)	D_{cs} ($1 million)	I_{sT} ($1 million)	E_{sIT} ($1 million)	E_{sITPV} ($1 million)	I_{NW} ($1 million)	E_{WPT} ($1 million)	E_{WPTPV} ($1 million)	C_{IDC} %	D_R ($1 million)	D_d ($1 million)	I_{IT} ($1 million)	E_{IT} ($1 million)	E_{ITPV} ($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	15[illegible]2	58.8	1	0	213	0.00	0.00	0	92	146	67	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	136	46	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	46	17
143.9	96.2	96.2	47.7	1	0	143	0.00	0.00	0	0	38	105	36	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	6
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
46.8	37.1	37.1	9.4	0	0	46	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_{ea}, dollars/bbl
C	8.09
E_o	2.78
E_{rc}	1.29
E_R	1.83
I_{ST}	1.04
E_{RT}	0.55
E_{sIT}	0.05
E_{IT}	0.42
E_{WPT}	0.00
Total	16.05
P_{ea}	16.48
E_r	0.43
E_n, $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:

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

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

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

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

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

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

$$E_{fIT}=\Sigma E_{fITPV}/\Sigma\Delta N_{pPV}, \text{ and}$$

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

The total equivalent amortized per-barrel cost is expressed as

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

The value of C_{ea} 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

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

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

The equivalent amortized per-barrel economic rent is expressed by

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

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, $(P+P_p)\Delta N_p-[i_R+i_{ST}+E_o+E_{PT}+E_{sIT}+E_{fIT}+(\Delta N_pE'_{tc})]$, 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 spreadsheet 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 1 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, $0.34E_B$, 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/m^3]), 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/m^3] in 1987—and increase it by \$0.25/bbl [\$1.57/m^3] 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 (years)	P (dollars/bbl)	ΔN_p (10^6 bbl)	ΔN_{pPV} (10^6 bbl)	I_g ($1 million)	i_R ($1 million)	i_{RPV} ($1 million)	i_{ST} ($1 million)	i_{STPV} ($1 million)	C ($1 million)	C_{PV} ($1 million)	E_s ($1 million)	E_{sPV} ($1 million)	E_{RT} ($1 million)	E_{RTPV} ($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	456	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	56	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_{NRs} ($1 million)	D_{rs} ($1 million)	D_{cs} ($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_{rt} ($1 million)	D_{ct} ($1 million)	I_{rT} ($1 million)	E_{RT} ($1 million)	E_{RTPV} ($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	−6	0.00	0.00	108	92	198	−204	−69	−51
179.6	50.9	88.6	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	96.1	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	175.6	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
165.2	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	67	23	6
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	23.6	−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_{ae}, dollars/bbl
C	8.12
E_o	2.81
E_{rc}	1.29
E_R	2.62
i_{ST}	1.48
E_{pT}	0.60
E_{sT}	0.12
E_{rT}	2.09
E_{wPT}	0.00
Total	19.14
P_{ea}	24.81
E_r	5.67
E_{rt}, $1 million	541.72
I_{AB}, $1 million	34.00

TABLE 5—FIELD XXX OPTIMAL PRODUCTION

t (years)	P (dollars/bbl)	ΔN_p (10^6 bbl)	ΔN_{pPV} (10^6 bbl)	I_g ($1 million)	I_R ($1 million)	I_{RPV} ($1 million)	I_{ST} ($1 million)	I_{STPV} ($1 million)	C ($1 million)	C_{PV} ($1 million)	E_s ($1 million)	E_{sPV} ($1 million)	E_{PT} ($1 million)	E_{PTPV} ($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	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	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	16	8	3	7
14	24.66	13	5	333	36	12	22	8	0	0	39	13	8	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	25.66	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	26.59	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	752	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 = $\ln(q_p/\Delta N_{ply})/n_{sv}$,

ΔN_{ply} = 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_{ply} occurs, and

t' = 0 for peak year in sampled production volume vector or n_{sv} for the year ΔN_{ply} 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_{NRt} ($1 million)	D_{rs} ($1 million)	D_{as} ($1 million)	I_{sT} ($1 million)	E_{sIT} ($1 million)	E_{sITPV} ($1 million)	I_{NW} ($1 million)	E_{WPT} ($1 million)	E_{WPTPV} ($1 million)	C_{IDC} %	D_{rt} ($1 million)	D_{at} ($1 million)	I_{rT} ($1 million)	E_{RT} ($1 million)	E_{RTPV} ($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
179.5	47.0	84.3	95.2	1	1	178	0.00	0.00	134	138	310	−131	−45	−30
332.9	90.7	146.4	186.5	3	2	330	0.00	0.00	21	116	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	64	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	24.6	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	−2.8	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_{se}, dollars/bbl	
C	8.45
E_o	2.82
E_{tc}	1.29
E_R	2.62
I_{ST}	1.55
E_{PT}	0.81
E_{sIT}	0.12
E_{RT}	1.98
E_{WPT}	0.00
Total	19.45
P_{se}	24.83
E_r	5.38
E_{rt}, $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

$$I_{\text{mar}} = \sum_{n_o=\Delta N_{pif}}^{\Delta N_{pil}} \left(\{[(\Delta N_{pPV})_{n_c} - (\Delta N_{pPV})_{n_c-1}]_{n_o}\}\right.$$
$$\left.\times\{(P+P_p)+[(P+P_p)_d-(P+P_p)_{d-1}]_{n_o}\}\right),$$

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

$$C_{\text{mar}} = \{\Sigma i_{RPV} + \Sigma i_{STPV} + \Sigma C_{PV} + \Sigma E_{oPV} + \Sigma E_{PTPV}$$
$$+ \Sigma E_{sITPV} + \Sigma E_{WPTPV} + \Sigma E_{JITPV} + [(E'_{tc})_{n_c}$$
$$\times \Sigma\Delta N_{pPV}]\}_{n_c} - \{\Sigma i_{RPV} + \Sigma i_{STPV} + \Sigma C_{PV} + \Sigma E_{oPV}$$
$$+ \Sigma E_{PTPV} + \Sigma E_{sITPV} + \Sigma E_{WPTPV} + \Sigma E_{JITPV}$$
$$+ [(E'_{tc})_{n_c-1}\Sigma\Delta N_{pPV}]\}_{n_c-1}.$$

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 $X=1.5$, $Y=1.5$, $n_{INC}=1$, $F_{pul}=0.42$, and $s_i=\sqrt{\Delta N_{prv}}$. The incremental volume is 4 million bbl [636×10^3 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 [3.5×10^6 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 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_{ea} = equivalent amortized cost, dollars/bbl [dollars/m^3]
C_f = field cost, dollars/bbl [dollars/m^3]
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_{rf} = 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/m^3]
E_{rt} = 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_{tc} = transportation cost, dollars/bbl [dollars/m^3]
E'_{tc} = actual transportation cost, dollars/bbl [dollars/m^3]
E_{Ta} = tariff, dollars/bbl [dollars/m^3]
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, %
i = 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, 10^6 bbl [10^6 m^3]
N_{pl} = amount of production after asset comes on line, 10^6 bbl [10^6 m^3]
ΔN_p = volume, 10^6 bbl [10^6 m^3]
ΔN_{pif} = first year of incremental production
ΔN_{pil} = last year of incremental production
ΔN_{pINC} = incremental volume, 10^6 bbl [10^6 m^3]
ΔN_{ply} = volume in last sampled year greater than 1, 10^6 bbl [10^6 m^3]
ΔN_{pp} = peak production volume for base case, 10^6 bbl [10^6 m^3]
ΔN_{pP} = primary volume, 10^6 bbl [10^6 m^3]
ΔN_{pPV} = discounted volume, 10^6 bbl [10^6 m^3]
ΔN_{psv} = peak production volume for sampled vector, 10^6 bbl [10^6 m^3]
P = price, dollars/bbl [dollars/m^3]
P_{ea} = equivalent amortized price, dollars/bbl [dollars/m^3]
P_p = pipeline profit, dollars/bbl [dollars/m^3]
q_{EL} = production at the economic limit, bbl/well/D [m^3/well/d]
q_{ELB} = base for F_{EL} exponent
q_p = peak production volume for sampled vector, 10^6 bbl [10^6 m^3]
s_i = size of increment, 10^6 bbl [10^6 m^3]
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_{tc} and E'_{tc} 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.

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[1]Underdevelopment (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.

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[2]Many 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

[3]ARCO'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.

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[4] A draft of Marks' paper is found in Attachment B.

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

Attachment A

TECHNICAL NOTE
ON ARCO'S KUPARUK EXAMPLE

Tax Effects of Drilling an Additional Well Under Current Law

Mr. James Weeks, Kuparuk Unit Manger for ARCO, provided testimony to the House Finance Committee on March 27, 1987. Examples of severance tax effects (see 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 BOPY - 90,168,000 BOPY)*($9/barrel) =
(109,000 BOPY)*($9/barrel) = $981,000

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

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

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

	Change In Annual Gross Revenue	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* × *ELF*

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* × *ELF*

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

<u>A Model to Evaluate the Economics of Drilling Additional Wells</u>

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 thing 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 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_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 0.090, and P_B is 0.91394.

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

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

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

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

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.

$$c = \left(\frac{1}{e^{a_B - .002}} - \frac{1}{e^{a_B}} \right) \Big/ \ln\left(\frac{\left(w + T^{\frac{x-1}{x}}\right)^x}{T^{x-1}} \right)$$

This coefficient calibrates f(w) such that as w = T (i.e. the number of wells is doubled), a_B 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 inputed (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.)

Price	Additional Wells
$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

	No Optimization		Optimization (100 wells)		Increased	Increased
	Wells	Volume (mmbbl)	Wells	Volume (mmbbl)	Wells	Volume (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

	$20 (100 wells)		$25 (316 wells)		Increased	Increased
	Wells	Volume (mmbbl)	Wells	Volume (mmbbl)	Wells	Volume (mmbbl)
1988	541	561	541	561	0	0
1989	551	513	622	513	71	0
1990	560	469	700	470	140	1
1991	569	429	774	430	205	1
1992	544	392	740	393	196	1
1993	521	359	709	360	188	1
1994	499	328	678	330	179	2
1995	477	300	649	302	172	2
1996	457	275	621	276	164	1
1997	437	251	594	253	157	2
1998	418	230	569	231	151	1
1999	400	210	544	212	144	2
2000	383	192	521	194	138	2
2001	366	176	498	177	132	1
2002	351	161	477	162	126	1
2003	336	147	456	148	120	1
2004	321	134	437	136	116	2
2005	307	123	418	124	111	1
2006	294	112	400	114	106	2
2007	281	103	383	104	102	1
2008	269	94	366	95	97	1
Total		5223		5251		28
Economic Rent ($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," Ruedrick 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.

Standard adds drill rig to Prudhoe field

Anticipates another dozen before end of year

3VSA 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.

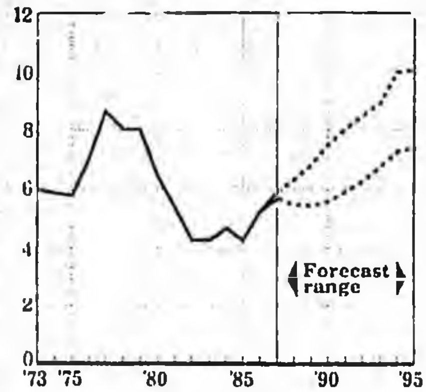
Currently stirring controversy is a proposal by Senate Finance Chairman Lloyd Bentsen (D., Texas). He recently got his committee to amend the pending trade bill to require the president to do whatever is necessary to keep oil imports from exceeding 50% of the U.S. supply, subject to congressional veto. 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, reluctantly 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.

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.

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 disruptions 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."

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 utilidor 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

Should Alaska change the ELF formula?

Yes

Guest Opinion

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 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 industry 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[illegible]table state—have not been [illegible]vincing.

I am [illegible]ngly 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

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 1985, 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. No other natural 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 businesses? 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 sensitive 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 ails 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.

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,

Ezra C Hunt for

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.

Nel

WALL STREET JOURNAL
APRIL 24 1987 p.7

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 In millions	1987 per share	1986 In millions	1986 per share	% chg.
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 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 increases.

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

But Lodwrick 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.

WALL STREET JOURNAL
April 30, 1987
Page 6

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.

eroding here, growing at Std + ARCO

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.

WALL STREET JOURNAL
April 30, 1987
Page 6

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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

SUBJECT: ANS/WTI Comparison
(Posted vs. Spot)

FROM: Bob Elliott BE
Research Analyst

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 to me
what does it mean?

02-001 A (Rev 10-84)

CHART 1

ANS: PRICE COMPARISON

(POSTED VS. MAY 87 SPOT)

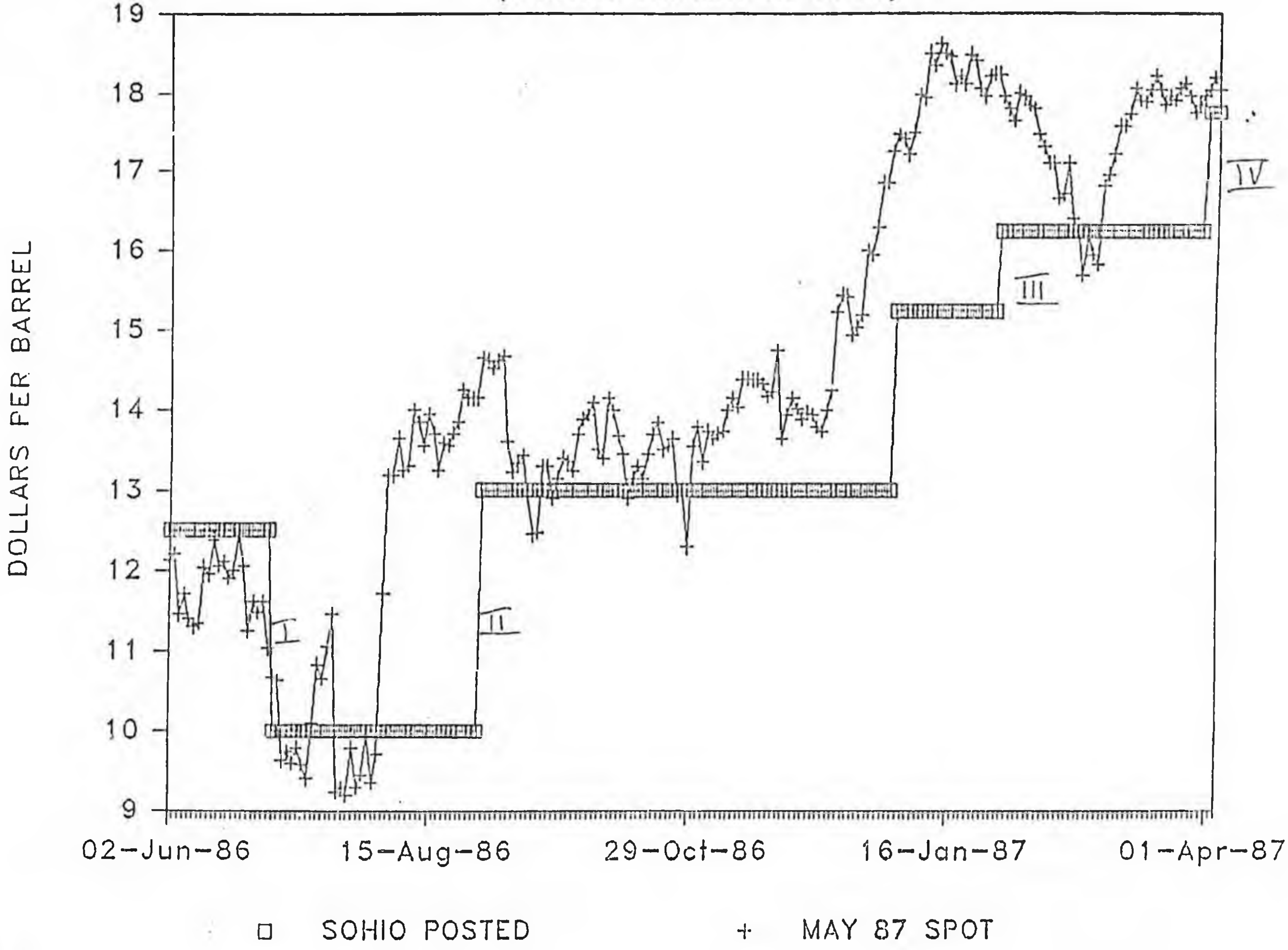


CHART 2

WTI: PRICE COMPARISON

(POSTED VS. MAY 87 SPOT)

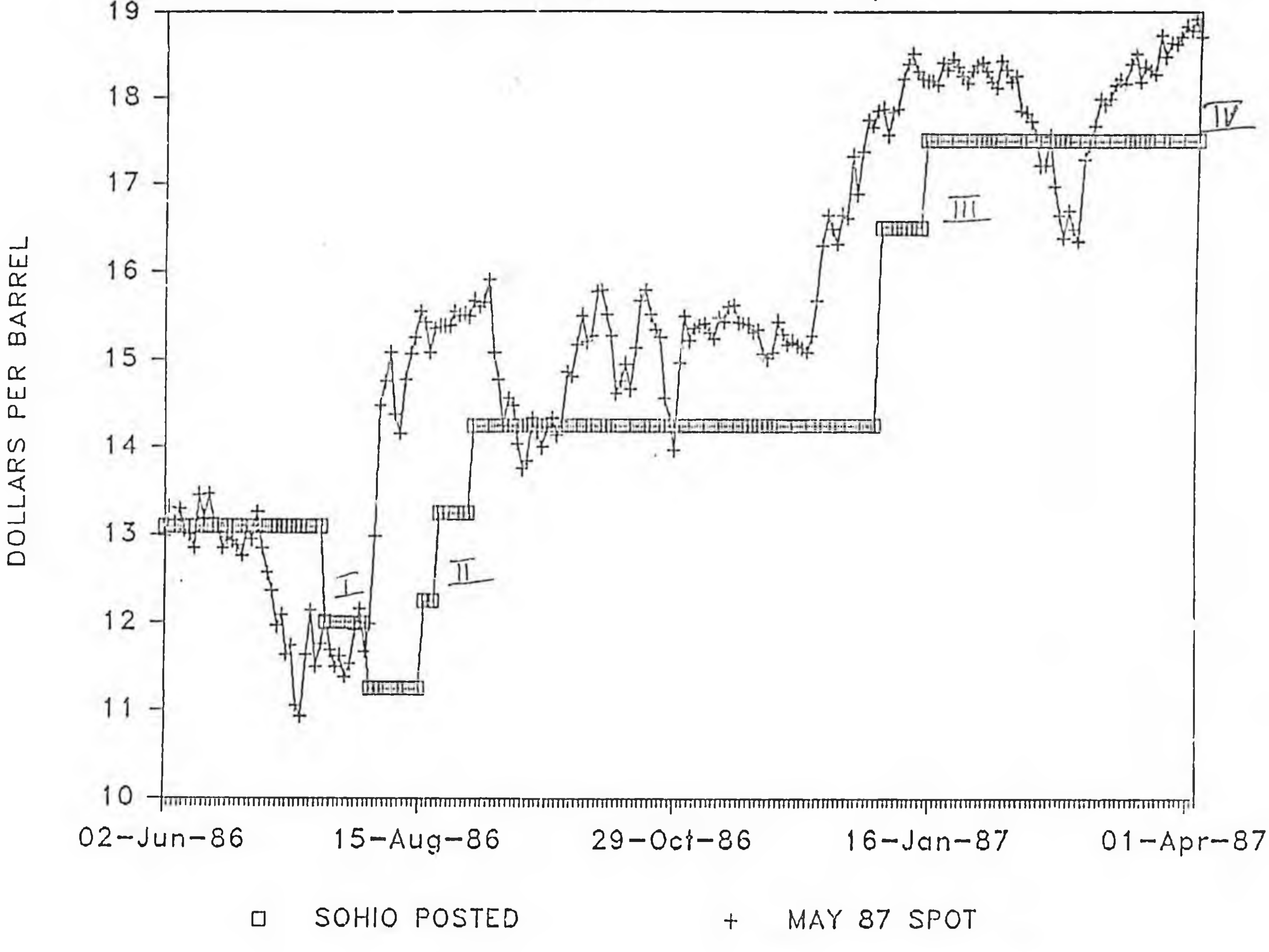
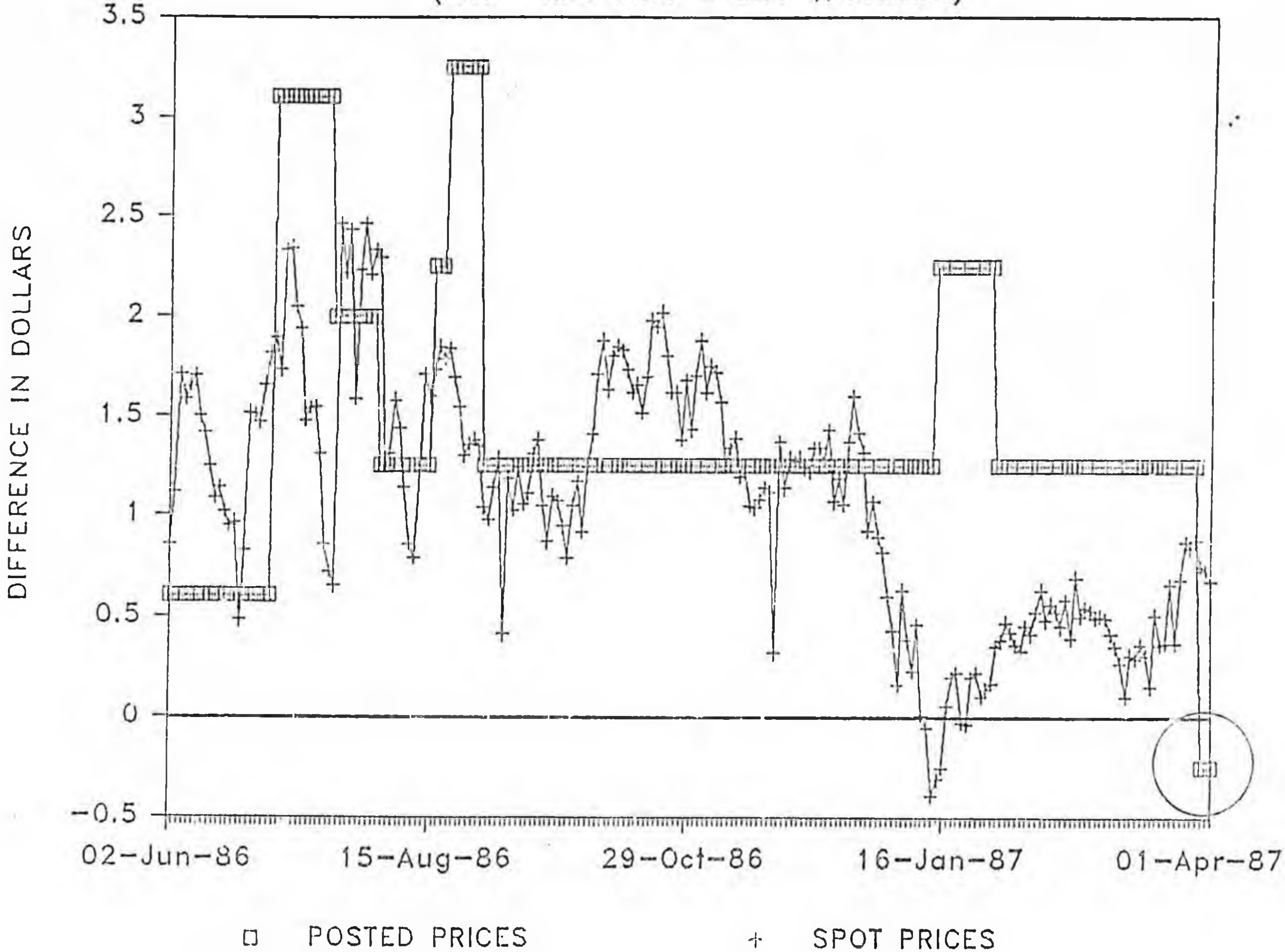


CHART 3

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 work-overs 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-

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. □