

HB

164

(FILE 3)

COMPUTING THE ALTERNATE ELF

The alternate Economic Limit Factor formula is:

$$\text{ELF} = (1 - \text{PEL}/\text{TP}) \text{EXP}[(55,000,000 * \text{WD}) / (\text{PEL} * \text{TP} / \text{Days})]$$

PEL (Production at the Economic Limit) =
 (300 barrels per day)*
 (average number of operating wells during the month)*
 (number of days of production for the month).

For example:

*300 barrels * 519 wells * 30 days = 4,671,000 barrels per month at the Economic Limit.*

TP (Total Production for the field) =
 (average number of operating wells during the month)*
 (number of days of production for the month)*
 (average daily production per well).

For example:

*519 wells * 30 days * 2750 barrels per well = 42,817,500 barrels of production per month.*

WD (Well Days) =
 (average number of operating wells during the month)*
 (number of days of production for the month).

For example:

*519 wells * 30 days = 15,570 well days.*

Days = the number of days in the month for which the tax is paid.
For example: In April, 30 days.

CALCULATION EXAMPLE

$$\text{Alternate ELF} = (1 - \text{PEL} / \text{TP}) \text{EXP}[(55,000,000 * \text{WD}) / (\text{PEL} * \text{TP} / \text{Days})]$$

$$(1 - 4,671,000/42,817,500) \text{EXP}[(55,000,000*15,570)/(4,671,000*42,817,500/30)]$$

$$= (1 - .1091) \text{EXP} (.1285)$$

$$= (.8909) \text{EXP} (.1285)$$

$$= .9856$$

FISCAL EFFECTS OF ELF ALTERNATIVES
 Additional Revenue (Millions) At the 30th percentile

	HB <u>164</u>	CSHB 154
1987	0.0	0.0
1988	76.7	88.7
1989	92.0	108.5
1990	98.5	117.6
1991	99.9	112.9
1992	105.6	117.8
1993	5.7	129.1
1994	3.9	110.4
1995	3.7	102.1
1996	4.5	97.7
1997	3.7	100.4
1998	2.0	88.2
1999	-0.2	90.9
2000	-0.1	69.0

Source: DOR fiscal notes, 3/2/87 and 3/19/87.

Prepared by CMB/Division of Policy, 3/20/85.

**STATE, FEDERAL AND INDUSTRY SHARES OF ALASKA OIL
RESOURCE INCOME: FISCAL 1982-1985**
(millions of dollars except as noted)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Fiscal year	Total Revenue	State Royalty	Sever. Conser. tax	Total Prop. tax	Total Oper. Costs	Total Deprec.	Total Acquis. Costs	Windfall Profits Tax
1982	\$16,456	\$1,553	\$1,581	\$276	\$940	\$602	\$1	\$2,018
1983	\$15,470	\$1,448	\$1,494	\$307	\$1,101	\$780	\$1	\$1,018
1984	\$14,955	\$1,409	\$1,393	\$358	\$1,259	\$998	\$1	\$412
1985	\$15,136	\$1,390	\$1,389	\$397	\$1,449	\$1,093	\$1	\$70

	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Fiscal Year	Uncap. Interest Expense	Explores. Costs	Admin. Costs	Other Deducs.	Total Deducs.	State Taxable Net Income	Corp. Petrol Income Tax	Federal Taxable Income
1982	\$721	\$191	\$236	\$149	\$8,268	\$8,188	\$669	\$7,519
1983	\$676	\$204	\$252	\$142	\$7,423	\$8,047	\$236	\$7,811
1984	\$614	\$219	\$265	\$136	\$7,064	\$7,891	\$265	\$7,626
1985	\$566	\$234	\$278	\$130	\$6,997	\$8,139	\$169	\$7,970

	[17]	[18]	[19]	[20]	[21] [22] [23]		
Fiscal Year	Federal Corp. Income Tax	Oil Industry Alaska Profits	Total Federal Tax	Total State Tax & Royalty	----Share of Oil Income----		
					State	Federal	Industry
1982	\$2,098	\$5,421	\$4,116	\$4,079	30%	30%	40%
1983	\$2,140	\$5,671	\$3,158	\$3,485	28%	26%	46%
1984	\$2,242	\$5,384	\$2,654	\$3,425	30%	23%	47%
1985	\$2,343	\$5,627	\$2,413	\$3,345	29%	21%	49%

SOURCES AND FORMULAS --

Column [1]: Vincent Wright, chief of research, to Mary Nordale, Commissioner of Revenue, Memorandum of October 31, 1985, Table 3.

Columns [2] & [3]: January 1986 DOR Revenue Sources, p. 39.

Columns [4] to [12]: Vincent Wright, loc. cit.

Column [13]: sum of columns [2] through [12]

Column [14]: column [1] - column [13]

Column [15]: Revenue Sources, p. 39.

Column [16]: column [14] - column [15].

Column [17]: column [16] * (production-weighted average tax rate -- 1982 = .279; 1983 = .274; 1984 = .294; 1985 = .294). Company effective rates for '82-84 from R. McIntire and R. Folen, "Corporate Income Taxes in the Reagan Years," Oct. 1984, pp. 32-36; '85 estimated by OMB.

Column [18]: column [16] - column [17].

Column [19]: column [8] + column [17].

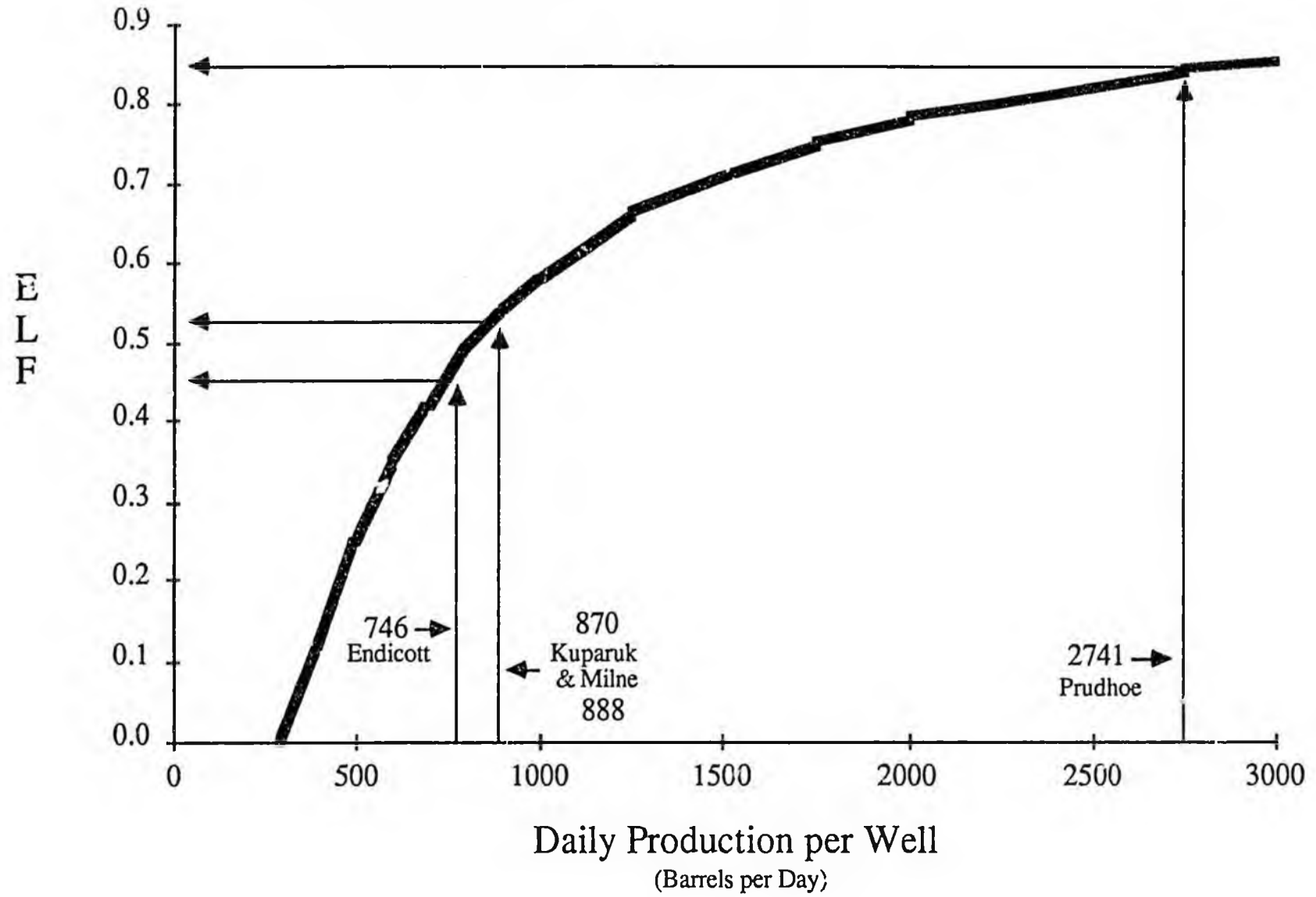
Column [20]: sum of columns [2], [3], [4], and [15].

Column [21]: (column [18])/(sum of columns [18], [19], and [20]).

Column [22]: (column [19])/(sum of columns [18], [19], and [20]).

Column [23]: (column [20])/(sum of columns [18], [19], and [20]).

Current Law



FISCAL EFFECTS OF ELF ALTERNATIVES
 Additional Revenue (Millions) At the 30th percentile

	<u>FY 87-88</u>	<u>FY 89</u>	<u>FY 90</u>	<u>FY 91</u>	<u>FY 92</u>
Option 1 (5 Yr. Delay)	75.0	91.4	97.7	95.7	101.5
Option 2 (Field ELF)	98.6	98.1	109.6	96.1	94.2
Option 3 (5 Yr. Delay, Shut "Trapdoor")	75.0*	91.7*	99.7*	97.7*	103.5*

SEE FISCAL NOTE

*Indicates OMB estimate pending DOR fiscal analysis due Thursday, 2/26.

ESTIMATED SEVERANCE TAX RATES*

	<u>Prudhoe Bay</u>	<u>Kuparuk River</u>	<u>Milne Point</u>	<u>Endicott</u>	<u>Lisburne</u>	<u>McArthur River</u>	<u>Granite Point</u>
Current Law	12.6%	7.8%	6.5%	5.6%	12.3%	1.1%	1.3%
Option 1 (5 Yr. Delay)	15.0%	7.8%	6.5%	5.6%	12.3%	1.1%	1.3%
Option 2 (Field ELF)	14.8%	10.7%	0.3%	0.3%	3.6%	0.0%	0.0%
Option 3 (5 Yr. Delay, Shut "Trapdoor")	15.0%	7.8%	6.5%	5.6%	12.3%	1.1%	1.3%

*North Slope values are forecast FY 88 averages; Cook Inlet values are estimated Dec 1986 rates.

OMB, Division of Policy, 2/26/87

Handwritten calculation:

$$\frac{15}{12.75} = 1.176 \approx 117.6\%$$

D R A F T

Under the authority of art. III, sec. 18, of the Alaska Constitution, I am transmitting a bill amending the formula for the oil and gas properties production tax economic limit factor (ELF) as it applies to oil. The bill will prevent a serious decline in production (severance) tax revenue anticipated in fiscal year 1988. In addition, it will reduce or eliminate entirely the severance tax on smaller fields, thereby providing added incentives for development of marginal North Slope fields and sustained production from Cook Inlet fields.

In 1981 the legislature passed an Act amending the corporate income tax and the severance tax. The Act substantially reduced the income taxes collected from Prudhoe Bay producers. Legislators were assured -- incorrectly, as it turned out -- that most of the reduction would be offset by two other provisions of the Act (ch. 116, SLA 1981), including a severance tax amendment that suspended the applicability of the economic limit factor (ELF) to Prudhoe Bay until 10 years after commercial production had begun. The 10th anniversary will come on June 20 of this year.

The fiscal note on the 1981 bill did not include projections beyond FY 1985, although an analysis by the Legislative

Finance Division did show that the ELF provision would cause state revenue to fall precipitiously in FY 1988. Governor Hammond noted this possibility, but expressed "full confidence in the ability of the legislature to deal at that time" with adverse revenue consequences, should they prove to be serious. [Statement of Governor Hammond on signing FCCSSB 524 (ch. 116, SLA 1981); see July 27, 1981 press release on oil and gas legislation, fourth page.]

It is now clear that the 1981 Act will have serious consequences for us in the coming fiscal year: state severance collections will be reduced by over 15 percent, and FY 88 revenue will fall by \$93,000,000 (already accounted for in the official "mean" forecast).

Delaying the applicability of the ELF to Prudhoe would avoid this loss, and would have the virtue of simplicity. Evidence presented to the legislature's Joint Special Committee on Tax Policy, however, suggests that delay would be undesirable on other grounds. It would not resolve the fiscal problem bequeathed us by the 1981 Act, only postpone it. Moreover, delaying the applicability of the ELF to Prudhoe would increase the uncertainty faced by Prudhoe owners regarding the future taxes, and would eventually create disincentives to further field development investments.

As conceived in 1977, the ELF was to be a "mechanism for scaling down the tax rate as the production declines toward the economic limit." [Alaska Dept. of Revenue, Alaska's Oil and Gas Structure: A Study With Recommendations for Improvement, 1977.] The attached bill returns to this concept and will once again apply the ELF equally to all fields, including Prudhoe Bay, as was the case before 1981.

The original ELF took account only of productivity per well. Since the Milne Point field opened in late 1985, evidence has accumulated that per-well productivity is by itself an inadequate measure of a field's relative ability to pay severance tax. The average well in the Milne field initially produced 950 barrels per day, giving it an ELF very nearly the same as the Kuparuk field, where the average well produced 1,000 barrels per day. Total production was 250,000 barrels per day in the Kuparuk field, while Milne Point produced less than a 10th of that amount.

Despite the smaller size, operators at Milne were still required to maintain a minimum complement of operating personnel, and pay the associated costs. These costs had to be divided, however, among far fewer total barrels. Although the two fields had almost identical per-well productivities, the smaller Milne Point field was clearly less profitable,

and the owners eventually elected to temporarily shut down production. This experience illustrated the deficiency of an ELF adjustment based solely on per-well productivity.

The attached bill will correct this perverse and unintended effect by adding total field productivity to the ELF calculation. Fields producing less than 119,500 barrels per day will have a lower ELF than under current law, while fields producing more than that amount will have a higher ELF. Prudhoe Bay will still receive a tax reduction when the ELF adjustment currently denied that field is returned, though the benefit will be smaller than would be the case under the "10th anniversary" provisions of the 1981 law taking effect in June. A somewhat higher ELF will apply to Kuparuk than is currently the case. Other known fields, including those contemplated but not yet in production, will benefit from lower ELFs and reduced taxes.

I wish that this legislation were not required. The period of low oil prices, however, has provided evidence that the ELF will need to provide a greater tax reduction for the smaller, more marginal fields if petroleum development in Alaska and the employment benefits of it, so badly needed in the current economic difficulties, are to be maximized. Unfortunately, in our current fiscal condition we simply

cannot afford to grant these needed reductions without offsetting increases in the state's two largest and most profitable fields. Neither can we afford to give Prudhoe Bay owners the tax reduction that will otherwise occur if the 1981 law is not changed. Indeed, should the legislature allow the programmed reduction to take effect, I will be compelled to seek reductions in appropriations beyond those already contemplated in the Administration budget.

I have restricted the changes to the minimum necessary to achieve the two purposes described above. In keeping with this principle, I have left for another time proposals that would change the so called "trap door" in the original 1977 severance tax. As they now stand, these particular provisions could allow producers to receive reductions in the "presumed production at the economic limit," which, in a period of very low oil prices, could open a "trap door" through which the taxpayer might entirely escape the severance tax.

This bill, along with forthcoming bills dealing with the individual income tax and disposition of permanent fund reserves, are cornerstone elements in the overall plan for long-term resolution of the state's current fiscal difficulties.

I urge your early consideration and passage of this bill.

Sincerely,

Steve Cowper
Governor

REQUEST _____

Bill Version: CSHB 164 (Fin)
Publish Date: HOUSE 3/30/87

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

Agency Affected: Revenue
BRU: Audit

Components: Oil & Gas

EXPENDITURES/REVENUES: (Millions of Dollars)

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

FUNDING: (Thousands of Dollars)

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

POSITIONS:

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

ANALYSIS: The above numbers represent the increase in general fund revenues if this bill becomes law. The key assumptions are introduction of a 55,000,000 scaling factor into the exponent of the current ELF formula and fixing the value of the Production at the Economic Limit (PEL) at 300 barrels per well per day. The production impact from FY88 through FY2005 represents a cumulative total loss of 20.7 million barrels.

Prepared By: Chuck Logsdon
Division: Office of the Commissioner

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

Approved by Commissioner: [Signature]
Agency: Revenue

Date: 3/19/87

- Distribution (by Agency preparing fiscal note)
- Legislative Finance
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- Office of Management and Budget
- Impacted Agency(ies)
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	Prodhee	Kuparuk	Milne	Endicott	Lisburne	Total
Arco	210.115258	4.917406	0	2.541607	2.116	219.585277
Exxon	113.107744	20.170151	0	.000757	4.170	137.279752
Mobil	113.107744	.1584	0	.170000	4.170	117.436144
Phillips	11.408124	.107075	0	0	0	11.515199
Chevron	4.354714	.047011	.255211	0	0	4.656936
Texaco	3.312036	0	0	0	0	3.312036
A. Hess	3.250702	0	0	0	0	3.250702
Shell	.050676	0	0	0	0	.050676
Marathon	.30667	0	0	0	0	.30667
BP	.061774	14.973304	0	0	0	15.035078
LL & E	.245336	0	0	0	0	.245336
Union	0	2.196992	0	.39795	0	2.594942
Conoco	0	0	.474789	0	0	.474789
CIRI	0	0	0	.024635	0	.024635
Total	519.99	42.91	.50	3.814635	10.58	576.864635

COMPANY FIELD EFFECT ADMIN. PROPOSAL

	Prodhee	Kuparuk	Milne	Endicott	Lisburne	Total	Delta Base
Schie	310.718044	4.07364	0	2.047936	2.182	320.72162	40.178232
Arco	133.585452	20.30596	0	.000932	4.364	158.756244	20.918580
Exxon	133.585452	.15624	0	.074432	4.364	138.999738	20.763146
Mobil	11.65346	.1519	0	0	0	11.80536	1.794555
Phillips	11.408124	.1085	0	0	0	11.516624	1.756321
Chevron	4.354714	.04774	.25396	0	0	4.656414	-.819243
Texaco	3.312036	0	0	0	0	3.312036	.509544
A. Hess	3.250702	0	0	0	0	3.250702	.500108
Shell	.050676	0	0	0	0	.050676	.132104
Marathon	.30667	0	0	0	0	.30667	.04710
BP	.061774	14.973304	0	0	0	15.035078	.178045
LL & E	.245336	0	0	0	0	.245336	.037744
Union	0	2.22208	0	.4360	0	2.65808	.063938
Conoco	0	0	1.14604	0	0	1.14604	.671252
CIRI	0	0	0	.02704	0	.02704	.002405
Total	613.34	43.4	1.4	4.18704	10.91	673.23704	96.372405

COMPANY FIELD EFFECT FIELD ELF

	Prodhee	Kuparuk	Milne	Endicott	Lisburne	Total	Delta Base
Schie	305.317018	8.250054	0	.700444	.744	315.167516	42.324126
Arco	131.074594	34.510006	0	.000220	1.500	167.574820	29.537172
Exxon	131.074594	.259164	0	.259620	1.500	133.361368	15.144408
Mobil	11.45187	.251465	0	0	0	11.703335	1.69303
Phillips	11.210778	.179975	0	0	0	11.390753	1.63045
Chevron	4.279303	.079189	.003628	0	0	4.3622	.525029
Texaco	3.254742	0	0	0	0	3.254742	.45225
A. Hess	3.194469	0	0	0	0	3.194469	.445875
Shell	.843822	0	0	0	0	.843822	.11725
Marathon	.301365	0	0	0	0	.301365	.041875
BP	.060273	24.771759	0	0	0	24.832032	10.014803
LL & E	.241092	0	0	0	0	.241092	.0335
Union	0	3.685008	0	.1197	0	3.804706	1.210646
Conoco	0	0	.016372	0	0	.016372	-.458416
CIRI	0	0	0	.00741	0	.00741	-.017225
Total	602.73	71.99	.02	1.14741	3.97	679.85741	102.992775

Questions and Answers On The ELF
with related
Briefing Materials

April 21, 1987

Office of the Governor

Office of Management and Budget Division of Policy

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Questions and Answers on the "ELF"

What does the ELF bill do?

A provision in current law will reduce Prudhoe Bay severance taxes on June 20, 1987. The ELF bill [CSHB-164 (fin) am] will prevent this reduction by substituting a new formula for computing the economic limit factor (ELF).

How did we get this provision in our law, and why does it take effect on June 20?

In 1981, the legislature amended the oil and gas corporate income tax and the severance tax. By changing from separate accounting to modified apportionment the act reduced income taxes for Prudhoe Bay producers. Legislators were assured -- incorrectly, as it turned out -- that most of this reduction would be offset by other provisions. These included a severance tax amendment which effectively suspended the applicability of the ELF to Prudhoe Bay "for the first ten years following the commencement of commercial production." The tenth anniversary will come on June 20 of this year. Since the ELF is a formula that reduces severance tax rates by variable amounts, depending on per-well production, suspending the ELF had the effect of increasing the tax.

How does the ELF formula work to reduce taxes?

The ELF is always a number between 1 and zero that gets multiplied times the nominal tax rate, producing the effective tax rate. Under current law the ELF is determined by the per-well productivity of the field. If productivity is high, the ELF is relatively close to 1 (.9 for example), and the field gets a small tax break. Fields with low per well productivity get a smaller ELF (.5 for example), and a larger tax break. Most fields in Cook Inlet are currently paying no severance tax because their low production per well gives them ELF's of zero. (Zero times the nominal tax rate of 12.25 percent gives an effective tax rate of 0.0 percent.).

When the ELF is calculated for Prudhoe it comes out to about .84, but (because of the 1981 amendments) during the first ten years of production the ELF doesn't apply to that field unless it is below .70, which is not expected to happen for some years.

Why didn't legislators realize in 1981 that this "ten year" business would cause us problems later?

Most legislators were probably unaware of the potential problem. The proposal was first unveiled to a free conference committee on June 22, and was adopted as the Free Conference Committee Substitute the next day. On June 24 it passed both houses and was on its way to the governor. Obviously there was little time to study the bill. The fiscal note included no projections beyond FY 1985.

Questions and Answers on the ELF

A post-session analysis by the Legislative Finance Division did show that the ELF provision would cause state revenue to fall sharply in FY 1988. Governor Hammond acknowledged this when he signed the bill, but expressed "full confidence in the ability of the legislature to deal at that time" with adverse revenue consequences, should they prove to be serious.

How much would Alaska lose from the cut in Prudhoe taxes?

The Department of Revenue estimates the fiscal year (FY) 1988 loss at \$93 million, or \$77 million under the more conservative "30 percent" forecast. The reduction is already accounted for in the official forecasts.

Will the loss be affected if oil prices go up or down?

Higher oil prices will result in increased severance tax revenue, and would mean bigger losses from allowing the ELF to apply at Prudhoe. Falling prices will reduce severance tax revenue, and will reduce the loss figure.

How would the ELF bill affect the expected revenue loss?

As originally introduced the bill would have prevented the ELF from applying to Prudhoe for an additional five years. The measure that emerged from the House took a more comprehensive approach: the ELF would be allowed to apply at Prudhoe, but the formula for calculating the ELF would be changed. Under the new formula (sometimes called the "alternate ELF"), severance tax revenue from Prudhoe would decline only slightly. Tax revenue from Kuparuk would increase, but all other producing fields would receive reductions.

The net effects of these increases and decreases produce \$88 million additional revenue in FY 1988, and \$108 million in FY 1989. By FY 2005 the gain will have diminished to \$29 million. The figures (see p. 15 for the complete long-run projections) are based on the state's deliberately conservative forecast of production and oil prices (the so called "30 percent" forecast).

How does the new ELF calculation in the bill differ from the ELF formula in present law?

The original ELF takes account only of productivity per well. Since the Milne Point field opened in late 1985, evidence has accumulated that per-well productivity is by itself an inadequate measure of a field's relative ability to pay severance tax. The average well in the Milne field initially produced 950 barrels per day, giving it an ELF very nearly the same as the Kuparuk field, where the average well produced 1,000 barrels per day. Total production was 250,000 barrels per day in the Kuparuk field, while Milne Point produced less than one-tenth of that amount.

Questions and Answers on the ELF

Despite the smaller size, operators at Milne were still required to maintain a minimum complement of operating personnel, and pay the associated costs. These costs had to be divided, however, among far fewer barrels. Although the two fields had almost identical per-well productivities, the smaller Milne field was clearly less profitable, and the owners eventually elected to temporarily shut down production. The experience illustrated the deficiency of an ELF adjustment based solely on per-well productivity.

The new ELF formula incorporated in the bill will correct this perverse and unintended effect by adding total field productivity to the ELF calculation. Fields producing less than 120,000 barrels per day will have a lower ELF (bigger tax break) than under current law, while fields producing more than that amount will have a higher ELF (smaller tax break).

Some industry sources say that Kuparuk is really a marginal field, and that it can't afford to pay the tax increase that would result from the new formula. How do you answer this?

Under the ELF bill the FY 88 effective tax rate in the Kuparuk River field will be 10.7 percent. This compares with 7.8 percent under the current law. The owners naturally don't like this increase. But the question is can they afford it? Kuparuk River is the biggest oil field in the nation, except for Prudhoe. Kuparuk produces 93 million barrels per year, compared with 60 million from the next biggest field, South Belridge in California. A big field like Kuparuk doesn't need the big tax break we are giving to the smaller fields.

Kuparuk produces \$664 million in annual gross revenue for its owners, after royalty is deducted. Under the bill the state will take \$71 million (mean forecast). This leaves \$593 million for the companies to cover their costs. Deducting field operating costs of \$1 per barrel leaves \$500 million net operating revenue per year. Based on ARCO's House Finance testimony on March 27, 1987, OMB estimates total field development investment at \$1.46 billion. Dividing investment by net operating revenue shows that *even at today's oil prices* the field would pay for itself in less than 3 years. Kuparuk has already been in production for over 5 years, at average prices much higher than today's prices. Kuparuk can afford to pay a 10.7 percent tax. Leaving Kuparuk at the current 7.8 percent rate would provide the owners with a major windfall.

But won't the new severance tax require the Kuparuk owners to pay a lot more than they would if the field were located in any other state?

The listing on the next page shows the tax per barrel that the Kuparuk owners would pay if the field were located in several of the larger oil producing states.

Questions and Answers on the ELF

<u>STATE</u>	<u>KUPARUK TAX PER BARREL</u>
Louisiana	\$1.75
New Mexico	\$1.13
Oklahoma	\$0.98
Wyoming	\$0.84
<i>Alaska (proposed)</i>	<i>\$0.76</i>
Texas	\$0.67
<i>Alaska (existing)</i>	<i>\$0.62</i>

Here is the same ranking on a percentage of value basis.

<u>STATE</u>	<u>KUPARUK TAX AS A PERCENT OF VALUE</u>
Louisiana	12.5 %
<i>Alaska (proposed)</i>	<i>10.7 %</i>
New Mexico	8.1 %
<i>Alaska (existing)</i>	<i>7.6 %</i>
Oklahoma	7.0 %
Wyoming	6.0 %
Texas	4.9 %

Each state designs its severance tax structure for the conditions in that particular state. In none of the other states is there an oil field even close to the size of Kuparuk, yet because the other states are much nearer to oil markets, the selling price of a barrel is much higher than in Alaska. Differences like these make it difficult to draw precise comparisons. The average oil well in Texas produces 145 barrels per day. A well producing at that rate in Alaska would pay no severance tax whatever. With respect to Kuparuk Alaska's severance tax with the new ELF will fall well within the range of severance taxes in other states.

A major oil company and an Anchorage banker say the state is already getting 96 percent of all oil and gas profit. Is this true?

No. The conclusion, which is said to come from a Department of Revenue study, is false. The state study projected future oil revenue under a variety of assumptions, and did not reach that conclusion. The Department has described the assertion that it did as "misleading."

The actual profits earned by the oil industry from production and transportation activity in Alaska during FY 1982-85 are shown on the attached sheets, along with the share that went to the state through royalties and taxes. Also shown are the state's estimates of the share of those profits removed from Alaska. Figures for 1986 and 87 are being compiled, and will be released soon.

Questions and Answers on the ELF

Some oil companies say the new ELF will have a bad effect on future development. Will the bill impact future production?

Yes, but the impact won't be large. A Department of Revenue analysis shows that the new ELF would increase North Slope output by 280,000 barrels during FY 1988 -- equal to 4 hours of flow through the TAPS pipeline. Effects taper off in later years and in 1993 become negative. The cumulative impact through FY 2005 is pegged at a negative 21 million barrels, equal to 5 days TAPS output at current rates. After 2005, however, much of this loss would be recouped, since the new ELF would increase incentives for production in the later stages of a field's life, when the incentive is really needed.

An oil company used an example to show that under the new formula the drilling of an additional well in an existing field will result in a higher tax on that field. They say that creates a disincentive to further drilling.

We have seen those calculations. Using figures typical for a field like Kuparuk, the example shows that drilling one additional well in the field will produce an additional \$981,000 in annual gross revenue. The objection seems to be that under the proposed severance tax a part of this gain would have to be paid to the state -- \$58,611 to be exact.

The example offered by the Kuparuk operators illustrates a loophole in the current ELF: under the circumstances described in the example, not only will the owners pay no tax on the incremental production from an additional well, owners will actually receive a *tax rebate* of \$37,846 annually. 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.

Under the proposed law producers who increase output through additional drilling will still be rewarded with a lower *average* tax rate, but the reduction will not completely eliminate the tax on the incremental revenue, nor will it provide them with the windfall of a tax rebate. If the new law is adopted it will close this loophole. (For more detail, see the technical note on p. 12.)

You said that the ELF bill had passed the House. What happens next?

The bill was sent to the Senate on April 3. Senate President Jan Faiks referred the measure to five different committees. No hearings have been scheduled.

OMB/Division of Policy
4/21/87

ELF DEJA VU

Some oil companies argue the existing ELF should not be changed. Ten years ago oil companies were also talking about the ELF, which was then being considered by the legislature. Here is a sample of what was being said then.

The ELF is "too complex, unrealistic, and fails to allow reasonable operating costs."

Larry Vavra, spokesman for Union Oil Co.

Fairbanks News-Miner, April 22, 1977

If it adopts the ELF, "Alaska will ... tip the scales against future development."

Monte Taylor, Exxon, USA

Anchorage Times, March 19, 1977

The proposed ELF legislation "would wipe out any remaining incentives for future development in Alaska."

Richard Donaldson, Standard Oil Co. of Ohio

Fairbanks News-Miner, March 25, 1977

The severance tax bill [with the ELF] will "result in significant losses in state income and fewer jobs...."

Monte Taylor, Exxon USA

Fairbanks News-Miner, March 26, 1977

"The [ELF] bill would increase state oil and gas severance tax revenues from the North Slope by \$7.2 billion over the 20 year life of the field...[T]he magnitude of the increase will cause a congressional backlash"

Ken Showalter, Standard Oil Co. of Ohio

Anchorage Times, April 22, 1977

The tax bills could make "subsidiary fields at Prudhoe Bay impossible to produce."

Richard Donaldson, Standard Oil Co. of Ohio

Alaska Advocate, April 21, 1977

"The only bitterness of the hearings came during an effort by Union Oil Co. spokesman Larry Wilson to read a lengthy and complex analysis of Alaska's tax structure. After about 40 minutes on the stand [House finance chairman Steve] Cowper cut him off with the observation that his testimony was going on too long.

"'You said your testimony was going to take 30 minutes,' Cowper said. 'Its been 40 minutes and now you say it will take another hour.'"

"'There are a couple of sides to this question you know,' Wilson shot back. 'We've got a lot of money at stake.'"

Anchorage Daily News, April 22, 1977

WERE DID THE OIL REVENUE GO?
(\$ Billions)

Oil Companies' Gross Revenues In Alaska, FY 1982-85	\$62.0
<i>Less:</i> Operating, Administrative, & Misc. Costs.	\$7.2
<i>Less:</i> Interest, Depreciation, & Other Capital Charges	\$6.1
<i>Less:</i> Federal Taxes	\$12.3
<i>Less:</i> State Taxes & Royalty	\$14.3
Oil Companies' Profits In Alaska, 1982-85	\$22.1
<i>Less:</i> New Investment In Alaska*	\$6.0
Profits Removed From Alaska, FY 1982-85	\$16.1

*Testimony of Harold Heinze, ARCO, to House Finance 4/12/85, Transcript, p. 130;
other sources shown on the following page.

OMB/Division of Policy, 4/8/87.

STATE, FEDERAL AND INDUSTRY SHARES OF ALASKA OIL
RESOURCE INCOME: FISCAL 1982-1985
(millions of dollars except as noted)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
	Total	State	Sever.	Total	Total	Total	Total	Windfall
Fiscal	Revenue	Royalty	Conser.	Prop.	Oper.	Total	Acquis.	Profits
year			tax	tax	Costs	Deprec.	Costs	Tax
1982	\$16,456	\$1,553	\$1,581	\$276	\$940	\$602	\$1	\$2,018
1983	\$15,470	\$1,448	\$1,494	\$307	\$1,101	\$780	\$1	\$1,018
1984	\$14,955	\$1,409	\$1,393	\$358	\$1,259	\$998	\$1	\$412
1985	\$15,136	\$1,390	\$1,389	\$397	\$1,449	\$1,093	\$1	\$70

	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
	Uncap.	Explore.	Admin.	Other	Total	State	Corp.	Federal
Fiscal	Interest	Costs	Costs	Deducs.	Deducs.	Net	Income	Taxable
Year	Expense					Income	Tax	Income
1982	\$721	\$191	\$236	\$149	\$8,268	\$8,188	\$669	\$7,519
1983	\$676	\$204	\$252	\$142	\$7,423	\$8,047	\$236	\$7,811
1984	\$614	\$219	\$265	\$136	\$7,064	\$7,891	\$265	\$7,626
1985	\$566	\$234	\$278	\$130	\$6,997	\$8,139	\$169	\$7,970

	[17]	[18]	[19]	[20]	[21]	[22]	[23]
	Federal	Oil	Total	Total	----Share of Oil Income---		
Fiscal	Corp.	Industry	Federal	State	State	Federal	Industry
Year	Income	Profits	Tax	Tax & Royalty			
1982	\$2,098	\$5,421	\$4,116	\$4,079	30%	30%	40%
1983	\$2,140	\$5,671	\$3,158	\$3,485	28%	26%	46%
1984	\$2,242	\$5,384	\$2,654	\$3,425	30%	23%	47%
1985	\$2,343	\$5,627	\$2,413	\$3,345	29%	21%	49%

SOURCES AND FORMULAS -

Column [1]: Vincent Wright, chief of research, to Mary Nordale, Commissioner of Revenue, Memorandum of October 31, 1985, Table 3.

Columns [2] & [3]: January 1986 DOR Revenue Sources, p. 39.

Columns [4] to [12]: Vincent Wright, loc. cit.

Column [13]: sum of columns [2] through [12]

Column [14]: column [1] - column [13]

Column [15]: Revenue Sources, p. 39.

Column [16]: column [14] - column [15].

Column [17]: column [16] * (production-weighted average tax rate - 1982 = .279; 1983 = .274; 1984 = .294; 1985 = .294). Company effective

rates for '82-84 from R. McIntire and R. Folen, "Corporate Income Taxes in the Reagan Years," Oct. 1984, pp. 32-36; '85 estimated by OMB.

Column [18]: column [16] - column [17].

Column [19]: column [8] + column [17].

Column [20]: sum of columns [2], [3], [4], and [15].

Column [21]: (column [18])/(sum of columns [18], [19], and [20]).

Column [22]: (column [19])/(sum of columns [18], [19], and [20]).

Column [23]: (column [20])/(sum of columns [18], [19], and [20]).

Office of Management and Budget
Division of Strategic Planning
revised April 11, 1986

ESTIMATED SEVERANCE TAX RATES*

	Prudhoe Bay	Kuparuk River	Milne Point	Endicott	Lisburne	McArthur River	Granite Point
Existing Law	12.6%	7.8%	6.5%	5.6%	12.25%	1.1%	1.3%
CSHB-164 (Fin.)	14.8%	10.7%	0.3%	0.3%	3.6%	0.0%	0.0%
Percent Change in Tax Rate	17.5%†	37.2%	-95.4%	-94.6%	-70.6%	-100.0%	-100.0%

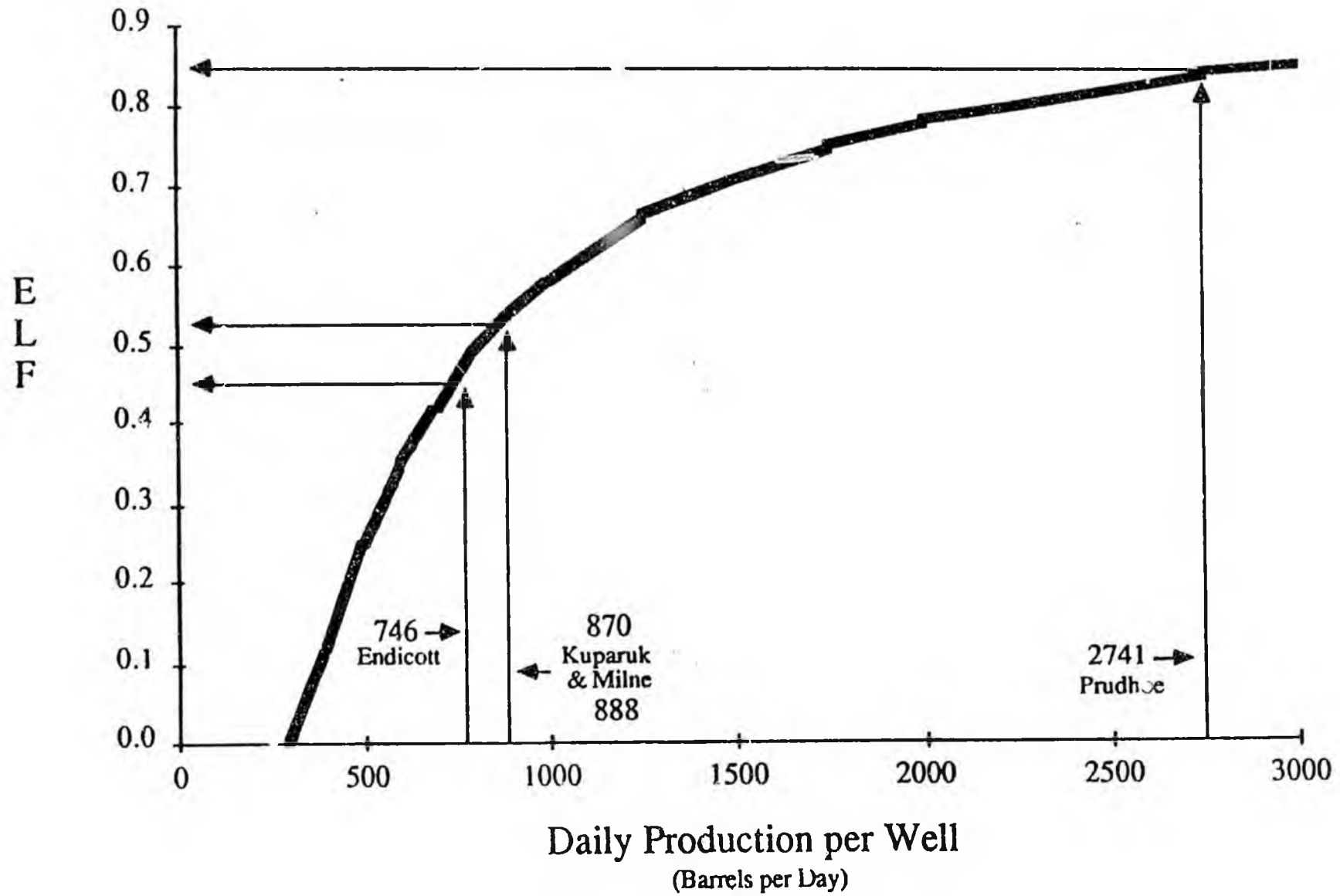
*North Slope values are forecast FY 88 averages; Cook Inlet values are estimated Dec 1986 rates;

Cook Inlet fields not listed have zero effective rates under all alternatives.

†CS reduces Prudhoe taxes by 1.4% compared with current (April 1987) rates.

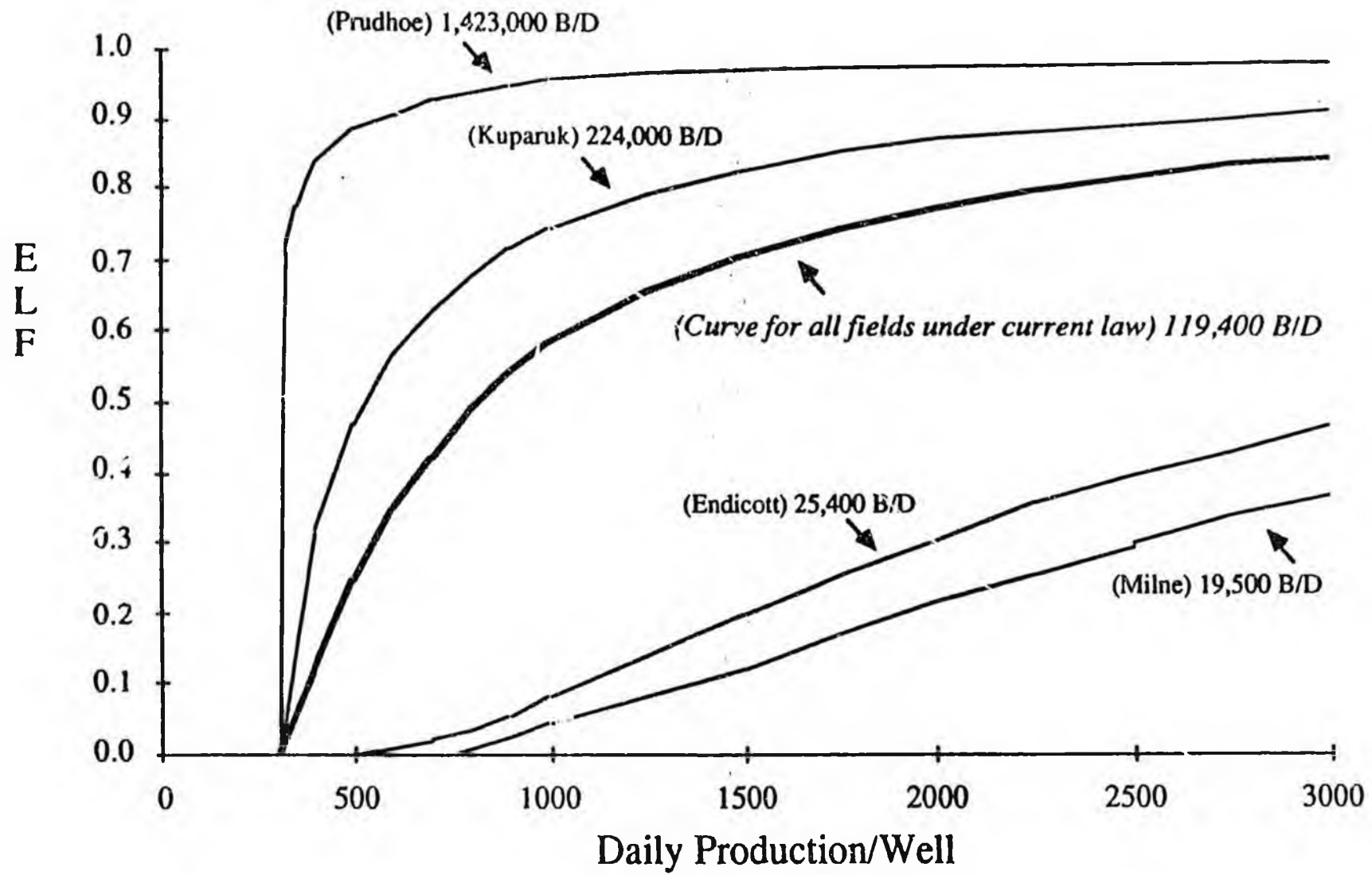
OMB, Division of Policy, 3/30/87

Current Law



Alternate ELF

Constant At 55,000,000



TECHNICAL NOTE

CN ARCO'S KUPARUK EXAMPLE

Tax Effects of Drilling an Additional Well Under Current Law

Mr. James Weeks, Kuparuk Unit Manger for ARCO, provided testimony to the House Finance Committee on March 27, 1987. Examples of severance tax effects (see following page) accompanied his testimony. The examples compare the severance tax effects of adding one additional well in the Kuparuk field under the current ELF and under the proposed ELF (CSHB 154 fin.). The examples show that the addition of one well producing just under 300 barrels per day would increase output from 90,168,000 barrels of oil per year (BOPY) to 90,277,000 BOPY. At the \$9.00 per barrel price assumed in ARCO's example, annual gross revenue to the owners increases by \$981,000.

$$(90,277,000 \text{ BOPY} - 90,168,000 \text{ BOPY}) * (\$9/\text{barrel}) =$$

$$(109,000 \text{ BOPY}) * (\$9/\text{barrel}) = \$981,000$$

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

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

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

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

**DRILLING/WORKOVER DISINCENTIVE
COMMITTEE SUBSTITUTE HB 164**

SEVERANCE TAX CALCULATION

CURRENT LAW

Field Rate × Wellhead Price × Severance Tax × 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 × 0.6204

= \$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]

COMPUTING THE ALTERNATE ELF

The alternate Economic Limit Factor formula is:

$$ELF = (1 - PEL/TP) \text{EXP}[(55,000,000 * WD) / (PEL * TP / \text{Days})]$$

PEL (Production at the Economic Limit) =
 (300 barrels per day)*
 (average number of operating wells during the month)*
 (number of days of production for the month).

For example:
 300 barrels * 519 wells * 30 days = 4,671,000 barrels per month at the Economic Limit.

TP (Total Production for the field) =
 (average number of operating wells during the month)*
 (number of days of production for the month)*
 (average daily production per well).

For example:
 519 wells * 30 days * 2750 barrels per well = 42,817,500 barrels of production per month.

WD (Well Days) =
 (average number of operating wells during the month)*
 (number of days of production for the month).

For example:
 519 wells * 30 days = 15,570 well days.

Days = the number of days in the month for which the tax is paid.
For example: In April, 30 days.

CALCULATION EXAMPLE

$$\begin{aligned} &\text{Alternate ELF} \\ &(1 - \text{PEL} / \text{TP}) \text{EXP}[(55,000,000 * \text{WD}) / (\text{PEL} * \text{TP} / \text{Days})] \\ &(1 - 4,671,000 / 42,817,500) \text{EXP}[(55,000,000 * 15,570) / (4,671,000 * 42,817,500 / 30)] \\ &= (1 - .1091) \text{EXP}(.1285) \\ &= (.8909) \text{EXP}(.1285) \\ &= .9856 \end{aligned}$$

Comparison of the March 1987 DOR Petroleum Production
Revenue Forecast and CSHB164
(Million \$)

Fiscal Year	March Official 30%	CSHB164 30%	March Official Mean	CSHB164 Mean	Delta 30%	Delta Mean
1987	1108.87	1114.39	1162.46	1168.36	5.52	5.9
1988	1189.59	1277.73	1437.59	1545.8	88.14	108.21
1989	1319.14	1427.18	1630.92	1759.88	108.04	128.96
1990	1441.42	1559.42	1753.22	1895.31	118	142.09
1991	1330.42	1446.18	1656.81	1800.41	115.76	143.6
1992	1431.66	1554.83	1808.98	1953.48	123.17	144.5
1993	1503.92	1638.57	1937.47	2084.7	134.65	147.23
1994	1550.06	1668.68	2289.29	2429.46	118.62	140.17
1995	1512.66	1625.97	2368.06	2504.08	113.31	136.02
1996	1470.59	1580.59	2329.13	2463.01	110	133.88
1997	1455.73	1568.57	2695.79	2832.53	112.84	136.74
1998	1424.09	1526.25	2658.19	2795.12	102.16	136.93
1999	1366.82	1471.58	2594.32	2728.56	104.76	134.24
2000	1312.73	1395.79	2541.24	2681.29	83.06	140.05
2001	1269.4	1345.11	2489.63	2630.86	75.71	141.23
2002	1223.23	1291.24	2454.13	2593.14	68.01	139.01
2003	1198.75	1258.23	2537.33	2674.64	59.48	137.31
2004	1174.99	1216.68	2516.98	2646.47	41.69	129.49
2005	1161.32	1190.35	2486.44	2588.74	29.03	102.3

NOTE: The column headed "Delta 30 %" shows the the revenue increase expected from the ELF bill sent to the Senate, as figured using the state's conservative "30th percentile forecast." The column headed "Delta Mean" shows the revenue increase expected if the state's more optimistic "mean forecast" is used.

Original sponsor: Rules/Governor

1 IN THE HOUSE BY THE FINANCE COMMITTEE

2 CS FOR HOUSE BILL NO. 164 (Finance) am
3 IN THE LEGISLATURE OF THE STATE OF ALASKA
4 FIFTEENTH LEGISLATURE - FIRST SESSION

5 A BILL

6 For an Act entitled: "An Act relating to the oil and gas properties pro-
7 duction tax; and providing for an effective date."

8 BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

9 * Section 1. AS 43.55.013(b) is repealed and reenacted to read:

10 (b) The economic limit factor for oil production of a lease or
11 property shall be computed according to the following formula:

12 $(1 - \{PEL/TP\}) \exp ([55,000,000 \times WD] / [PEL \times TP / \text{Days}])$

13 where: PEL = the monthly production rate at the economic limit;

14 TP = the total production during the month for which the tax
15 is to be paid;

16 WD = the total number of well days in the month for which
17 the tax is to be paid;

18 Days = the number of days in the month for which the tax is to
19 be paid; and

20 where "exp" indicates that the expression following it is an exponent.

21 * Sec. 2. AS 43.55.013(d) is amended to read:

22 (d) The monthly production rate at the economic limit for a
23 lease or property is presumed to be 300 barrels times the number of
24 well days for the lease or property during the month for which the tax
25 is to be paid. The taxpayer or the department may rebut this pre-
26 sumption at a formal hearing under AS 43.05 240 by providing clear and
27 convincing evidence of a different monthly production rate at the
28 economic limit for the lease or property. The hearing shall be held
29 before February 15 of the year or within six months after commencement

1 of oil production for a lease or property. The monthly production
2 rate at the economic limit for the lease or property based upon the
3 clear and convincing evidence of the taxpayer or the department shall
4 be calculated by dividing the value determined under (f) of this
5 section into the average monthly direct operating cost determined
6 under (e) of this section and shall be used for purposes of this
7 section for all oil production during that calendar year from the
8 lease or property.

9 * Sec. 3. This Act applies to oil produced after May 31, 1987.

10 * Sec. 4. This Act takes effect immediately under AS 01.10.070(c).

TABLE 1

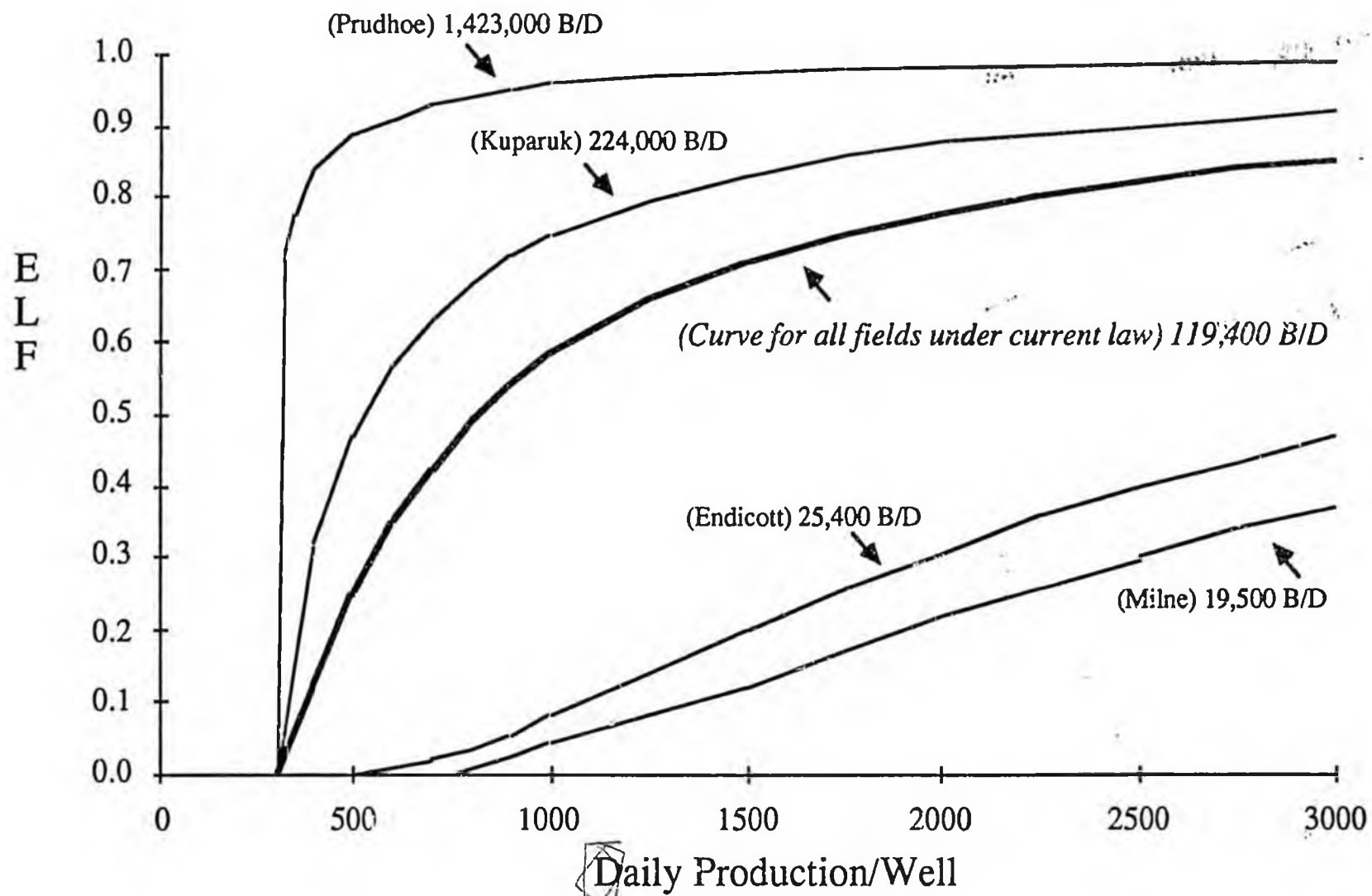
GIANT OIL FIELDS OF THE U.S. BY TOTAL RECOVERY
(Source: Oil & Gas Journal, Feb. 24, 1986)

<u>Field Name</u>	<u>Total Recovery Billion Barrels</u>	<u>Percent Recovery</u>	<u>Oil In Place Billion Barrels</u>
Prudhoe Bay, AK	9,365	39.3	23,800
East Texas, TX	5,529	79.0	7,000
Willington, CA	2,504	25.8	9,693
Midway-Sunset, CA	2,091	33.8	6,190
Yates, TX	2,000	50.0	4,000
Kern River, CA	1,947	47.9	4,062
Wasson, TX	1,803	38.0	4,748
Slaughter/Levelland, TX	1,522	53.9	2,822
Elk Hills, CA	1,473	53.0	2,780
Panhandle, TX	1,403	23.2	6,060
Sho-Vel-Tum, OK	1,373	44.3	3,100
Kuperuk River, AK	1,300	40.6	3,200
Kelly/Snyder/Diamond, TX	1,252	57.9	2,161
Ventura/Rincon, CA	1,119	18.7	6,000
Greta/Tom, TX	930	68.0	1,376
Long Beach, CA	930	28.0	3,317
Goldsmith-Andeotor, TX	921	43.4	2,124
Eunice Area, NM	900	45.0	2,000
Hawkins, TX	837	61.7	1,356
Coalinga, CS	784	17.4	4,505
Conroe, TX	759	62.9	1,207
Belridge, S, CA	755	53.9	1,400
Oklahoma City, OK ¹⁾	749	29.7	2,520
Rangely, CO	716	42.6	1,682
Hasting, TX	699	37.6	1,860
Cowden Complex, TX	658	54.4	1,209
McElroy-Dune, TX	658	25.9	2,544
Buena Vista, CA	657	25.0	2,630
S. Timbalier, LA	656	38.0	1,726
Bradford, PA	653	17.8	3,500
Santa Fe Springs, CA	622	28.3	2,200
Salt Creek, WY	616	40.6	1,518
Caillon Island, LA	612	54.0	1,133
May Marchand, L.	603	38.4	1,571
Sprayberry, TX	584	6.6	8,088
Greater Seminol, TX	583	50.8	1,148
Webster, TX	567	76.5	741
Wichita Co., TX	556	27.8	2,000
Smackover, AR	553	36.6	1,512
Pt. Argeuello, CA	547	18.2	3,000
Burbank, OK	531	24.6	2,160
McArthur River, AK ²⁾	531	39.7	1,336
San Ardo, CA	530	36.6	1,450
Van, TX	517	57.9	893
Lima-Indiana, IL	514	49.9	1,030
Elk Basin, WY	500	35.0	1,430
Golden Trend, OK	500	30.0	1,650
Kettleman, CA	500	25.0	2,000
Old Illinois, IL	500	35.0	1,430
West Sak, AK	-0-	0.0	25,000
Total U.S. 52 Fields	59,174	31.49*	187,861
Total Alaskan 4 Fields	11,196	20.99*	53,336

* Average

Alternate ELF

Constant At 55,000,000



203

FISCAL NOTE

Bill Version: CSHB 164(Res)
 Publish Date: HOUSE 3/20/87

REQUEST

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

Agency Affected: Revenue
 BRU: Audit

Components: Oil & Gas

EXPENDITURES/REVENUES: (Millions of Dollars)

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

FUNDING: (Thousands of Dollars)

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

POSITIONS:

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

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

Prepared By: Chuck Logsdon
 Division: Office of the Commissioner

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

Approved by Commissioner: [Signature]
 Agency: Revenue

Date: 3/19/87

Distribution (by Agency preparing fiscal note):

- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

3/19 Tom Williams CIRI

hard times

> 1/2 PB oil has bn recov'd

tax increase will chill new dev't

Sund: p 22 of Tax Ct -

Key: price of oil the most imp't consid'n Wms: several assumptions

> imp't than the tax - dec'n to drill add'l dev't wells are >
dep't on tax'n (a factor) - price is more important - (Gila, west end)

Sund: ELF is a method of reducing taxes - stability in state revenues - Wms: June 20 triggering can be viewed as a risk, but need stability, PB dec'n to be subj. to ELF -

Navarre: ~~what~~ dev't dec'n at PB aff'd by serv' tax? Wms: indy has prob'ly recovered its costs, not marginal problem now but poss'ly after June 20 it would be - CIRI interest in ~~the~~ Embert - small matters will hv an effect

Kentville: separate acct'g part of the problem

Mark Hazlewood ARCD

CS is substantially more overvalued

taxes are inc'ly imp't in fight cred'ns for oil dev't

Wyo/La hv rec'ly reduced state taxes - Kansas, OK, MT are prop'ly tax rdn's; Hermiton tax rdn prop'ls -

matrice fields, onter-field dev't

15% serv' wd reduce infield dev't by up to 30%, shorten problem by 3 years -

State Chambers sez > 60% of state's economy is related to oil most impact wd be on new dev't, dec'n whether or not to drill, infield dev't -

What problem impact? →

HB 164 #3 3/19 Cont.

Sund: does past profit affect dec's now? Haylewood: hist serv tax rate is in Atk - Sund: how much prod'n wd be lost? Haylewood: PB only, HB 164, even w/ slightly h'g prices, cd leave ~ 100MM bbls in the ground - Key: - origin to maximize prod'n under statutes/leases/unit agmts - Haylewood: don't blv the lease req's prod'n of uneconic barrels - have to date att'd to accel. Kupank problem - new tax policy wd be a factor that might reduce pace of dev't -

Navarre: need to know rev. impact to state if the 100 MM bbls fig. is accurate

Sun: TAPS tariff

Kerrula - royalty better in other states?

Tom Painter - CONOCO - this leg'n can positively infl'c dev't of ngl fields - not speaking on beh. of Milne Unit - mutual benefit for state + ind'y - need tax + other econ'c inc's -

substantial imm. inc' for fields \approx 120k bbl/day

Conoco supp's r rex passage of HB 164

might econ'c of ngl fields, foresight for use dev't

future dev't dec's wd be much affected by state gov't's abilities to deal w/ econ'c probs - all US producers are marginal -

Sund: Milne prod'n dec'n - Tom price, then margins

Pouchot: ~~TAPS~~ Milne pipeline tariff - Tom: \$1.91/bbl, owned by wkg interest owners (among state prod'rs)

Zawacki - % of Conoco prod'n Tom: not producing now

CSHB 164 #3 3/19 cont

Don Cornett? / Erkon - 48% rdex in down. cap. spending -

AK places a very hi burden on ind'y -

state share of wellhead value up to 73% -

prop'd CS - assumes large fields can assume h'ir costs -
inaccurate -

"covenant" in 1978

Navarre/Sund

Bob Van Hook Standard + Jim Palmer

last year's testimony

3 maj. projs 86-87 - Lisburne / Endicott / Ctl gas facly at

PB - 1.4 B bbls

HB 164 - reflects a theory that ELF shld apply everywhere but

frudite - AK has hi st serv' taxes - \$460-610m

tech'l progress - DOR doesn't account for these - major projs

cd be foregone - can't accurately predict foregone proden -

CSHB - > exp'v to enlarge a field -

Davis/Pancho

exploration is geared tow disc'y of large prod'v fields -

Sund

PB is going to be a very diff't field in the future -

K - econ'x of west end dev't - Van Hook - PB proden tax

treatment - will be treated diff'ly than Lisburne - K the

CS wd create inc'v for dev't of stand-alone Lisburne-type

dev't - Van Hook - CS might enhance Lisburne, but avail

funds for dev't are most imp't - econ'x of alt'v inv'ts..

Sam: PEL h'g/rebuttal, 300 bbl wh'y OK, see any need to use?

Van Hook - very imp't IF prices are very low - also when

major fields are in decline Sam: poss "double-whammy"

CSHB 164 #3 3/19 cont

Jay Shelby - Strategy - RDC / Common Sense -

Chick Becker ASIA

4-6 yr. transition in spending is needed

Geo Krusz - State Chamber

Lo Ann / John H / Ned

field approach -

1) should we repeal the 10-year provision?

Kuparuk should have an ELF -

→ what would be the diff'c betw. today's ELF, the 1.0 ELF, and .75 if the 10-year provision is repealed?

strategy: include + discuss vs discuss + amend?

Gregg/Chuck →
impk on Lisburne

2) which exponent to use?

SS -

Chuck
get the other charts done

3) do include the PEL big Δ -

4) title?

5) orgz the big Web. -

Sund-deser CS? or Sam -

Gregg/Chuck -

6) Tom Wm's paper -

7) royalty comparison - Frank -

→
impax of ELF on royty and corp inc. tax -

do we lose income in other areas?

Chuck Logsdon

field approach -

run various experiments -

37/48/55/70

tables, charts -

parameters - oil prices/field size -

→ Vince has copies of all of it -

→ main diff' is that the forecast basis is different -
will essentially need the March assumptions - will take
a week or so -

→ forecasting is on the field ~~of~~ basis

→ hv run Tom Warr's analysis -
indicates effect on inc. to drill wells
b/c it's incomplete - simplified, too specific
there are imp't econ. issues - other costs than
tax effects.

→ repealing 10-year wd be redundant - only Lisburne +
Purdue hv > .7 ECF; c'd get to a point where a
small, prod'n field wd fall under it -

~~the law currently states ECF~~ 1) law currently states ECF
for Purdue 4.80 floor is not a floor - to address service

2) P&L doesn't help on floor or P'serv tax revenue
tends to minimize the trap door problem -

→ need a trap door provision - the ^{Admin} attempt to set the



PEL is a halfhearted attempt to close trap-door -
[it has low prices, cost to produce, + has a low ECF
that reduces its flow

Gregg

- repeal PCC by
Lisburne
Kopank

- fn's - field + well

- exponents? - the range - 55, 48, 37 - most \$ -
charts comparing.

- Tom Williams' paper - criticisms of field approach

- repealing 16 year?



Official Business

Alaska State Legislature

House

P.O. BOX V
State Capitol
Juneau, Alaska 99811

TO: Rep. Sam Cotten, Co-Chair
Rep. Adelheid Herrmann, Co-Chair
Resources Committee members

FROM: Ned Farquhar, staff *Ned Farquhar*

SUBJECT: Proposed CSHB 164 (Res)

DATE: March 18, 1987

Attached is a proposed committee substitute for HB 164 which will be presented at today's joint Resources-Finance hearing by Rep. Sund. Administration representatives will be present to explain the import of the changes described below.

Section 1 of the bill repeals the existing ELF formula and the ten-year moratorium provision for certain fields, and reinstates a new ELF formula based on the production of fields rather than wells.

Section 2 eliminates the opportunity for a producer to attempt to rebut the presumption that the PEL (production at the economic limit) is 300 bpd.

Section 3 repeals existing law that relates to the PEL rebuttal and hearing provision, eliminated in Section 2.

Section 4 makes the bill retroactive. There is some question as to the constitutionality of this section because tax payments have already been made, on a monthly basis, under existing law.

Section 5 establishes an immediate effective date for the bill.

cc: Finance Committee members and staff

w01257hcB
Bannister
3/17/87

Original sponsor: Rules/Governor

1 IN THE HOUSE

BY THE RESOURCES COMMITTEE

2 CS FOR HOUSE BILL NO. 164 (Resources)

3 IN THE LEGISLATURE OF THE STATE OF ALASKA

4 FIFTEENTH LEGISLATURE - FIRST SESSION

5 A BILL

6 For an Act entitled: "An Act relating to the oil and gas properties pro-
7 duction tax; and providing for an effective date."

8 BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

9 * Section 1. AS 43.55.013(b) is repealed and reenacted to read:

10 (b) The economic limit factor for oil production of a lease or
11 property shall be computed according to the following formula:

12
$$(1 - [PEL/TP]) \exp ([55,000,000 \times WD] / [PEL \times TP/Days])$$

13 where: PEL = the monthly production rate at the economic limit;

14 TP = the total production during the month for which the tax
15 is to be paid;

16 WD = the total number of well days in the month for which
17 the tax is to be paid;

18 Days = the number of days in the month for which the tax is to
19 be paid; and

20 where "exp" indicates that the expression following it is an exponent.

21 * Sec. 2. AS 43.55.013(d) is amended to read:

22 (d) The monthly production rate at the economic limit for a
23 lease or property is [PRESUMED TO BE] 300 barrels times the number of
24 well days for the lease or property during the month for which the tax
25 is to be paid. [THE TAXPAYER MAY REBUT THIS PRESUMPTION AT A FORMAL
26 HEARING UNDER AS 43.05.240 BY PROVIDING CLEAR AND CONVINCING EVIDENCE
27 OF A DIFFERENT MONTHLY PRODUCTION RATE AT THE ECONOMIC LIMIT FOR THE
28 LEASE OR PROPERTY. THE HEARING SHALL BE HELD BEFORE FEBRUARY 15 OF
29 THE YEAR OR WITHIN SIX MONTHS AFTER COMMENCEMENT OF OIL PRODUCTION FOR

1 A LEASE OR PROPERTY. THE MONTHLY PRODUCTION RATE AT THE ECONOMIC
 2 LIMIT FOR THE LEASE OR PROPERTY BASED UPON THE CLEAR AND CONVINCING
 3 EVIDENCE OF THE TAXPAYER SHALL BE CALCULATED BY DIVIDING THE VALUE
 4 DETERMINED UNDER (f) OF THIS SECTION INTO THE AVERAGE MONTHLY DIRECT
 5 OPERATING COST DETERMINED UNDER (e) OF THIS SECTION AND SHALL BE USED
 6 FOR PURPOSES OF THIS SECTION FOR ALL OIL PRODUCTION DURING THAT CALEN-
 7 DAR YEAR FROM THE LEASE OR PROPERTY.]

8 * Sec. 3. AS 43.55.013(e) and (f) are repealed.

9 * Sec. 4. Sections 1 - 3 of this Act are retroactive to January 1,
 10 1987.

11 * Sec. 5. This Act takes effect immediately under AS 01.10.070(c).
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047417

Current Law (MM PD)

	Prudhoe	Kuparuk	Milne	Endicott	Lisburne	Total
Sohio	262.915268	4.917486	0	2.594631	2.116	272.543389
Arco	113.933044	20.571351	0	.980758	4.252	139.476805
Exxon	113.933044	.154476	0	.796638	1.252	116.117299
Mobil	9.85082	.150105	0	0	0	10.000925
Phillips	9.85082	.107075	0	0	0	9.957895
Chevron	3.604758	.047201	.195212	0	0	3.847171
Texaco	2.802492	0	0	0	0	2.802492
A. Hess	2.750594	0	0	0	0	2.750594
Shell	.72572	0	0	0	0	.72572
Marathon	.25949	0	0	0	0	.25949
BP	.051098	14.765531	0	0	0	14.816629
LL & E	.207592	0	0	0	0	.207592
Union	0	2.196992	0	.39795	0	2.594942
Conoco	0	0	.474788	0	0	.474788
CIRI	0	0	0	.024635	0	.024635
Total	518.98	42.91	.58	3.814635	10.58	576.864635

COMPANY FIELD EFFECT ADMIN. PROPOSAL

	Prudhoe	Kuparuk	Milne	Endicott	Lisburne	Total	Delta Base
Sohio	310.718044	4.97364	0	2.847936	2.182	320.72162	48.178232
Arco	133.585452	20.80596	0	.000332	4.364	158.756244	20.918588
Exxon	133.585452	.15624	0	.874432	4.364	138.980124	20.763146
Mobil	11.65346	.1519	0	0	0	11.80536	1.794555
Phillips	11.403124	.1085	0	0	0	11.511624	1.756321
Chevron	4.354714	.04774	.25396	0	0	4.656414	-.819243
Texaco	3.312036	0	0	0	0	3.312036	.509544
A. Hess	3.250702	0	0	0	0	3.250702	.500108
Shell	.858676	0	0	0	0	.858676	.132104
Marathon	.30667	0	0	0	0	.30667	.04718
BP	.061334	14.93394	0	0	0	14.995274	.178845
LL & E	.245336	0	0	0	0	.245336	.037744
Union	0	2.22208	0	.4368	0	2.65888	.063938
Conoco	0	0	1.14604	0	0	1.14604	.671252
CIRI	0	0	0	.02704	0	.02704	.002405
Total	613.34	43.4	1.4	4.18704	10.91	673.23704	96.372405

COMPANY FIELD EFFECT FIELD ELF

	Prudhoe	Kuparuk	Milne	Endicott	Lisburne	Total	Delta Base
Sohio	305.345918	8.250054	0	.780444	.794	315.167516	12.324128
Arco	131.274594	34.512006	0	.000268	1.588	167.374828	29.537172
Exxon	131.274594	.259164	0	.259628	1.588	133.561386	15.144408
Mobil	11.45187	.251965	0	0	0	11.703835	1.69303
Phillips	11.210778	.179975	0	0	0	11.390753	1.65045
Chevron	4.279383	.079189	.003628	0	0	4.3622	.525029
Texaco	3.254742	0	0	0	0	3.254742	.45225
A. Hess	3.194469	0	0	0	0	3.194469	.443875
Shell	.843822	0	0	0	0	.843822	.11725
Marathon	.301365	0	0	0	0	.301365	.041875
BP	.060273	24.771759	0	0	0	24.832032	10.014803
LL & E	.241092	0	0	0	0	.241092	.0335
Union	0	3.685388	0	.1197	0	3.805588	1.210646
Conoco	0	0	.016372	0	0	.016372	-.458416
CIRI	0	0	0	.00741	0	.00741	.017225
Total	602.73	71.99	.02	1.14741	3.97	679.85741	102.992775

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

Bill Version: H.B. 164
Publish Date: _____

REQUEST _____

Revision Date: March 16, 1987
Title: Extending imposition of economic
limit factor-oil and gas production tax.
Sponsor: Governor
Requestor: Rules

Agency Affected: Revenue
SRU: audit
Components: _____

EXPENDITURES/REVENUES: (Thousands of Dollars)

	FY 87	F. 88	FY 89	FY 90	FY 91	FY 92
OPERATING						
PERSONAL SERVICES	-	-	-	-	-	-
TRAVEL	-	-	-	-	-	-
CONTRACTUAL	-	-	-	-	-	-
SUPPLIES	-	-	-	-	-	-
EQUIPMENT	-	-	-	-	-	-
LANDS & STRUCTURES	-	-	-	-	-	-
GRANTS, CLAIMS	-	-	-	-	-	-
MISCELLANEOUS	-	-	-	-	-	-
TOTAL OPERATING	-	-	-	-	-	-
CAPITAL	-	-	-	-	-	-
REVENUE	-	-	-	-	-	-

FUNDING: (Thousands of Dollars)

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

POSITIONS:

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

ANALYSIS: Attach a separate page if necessary

Prepared By: Steven E. Kettei
Division: Audit

Phone: 465-2320

Date: March 16, 1987

Approved by Commissioner: _____
Agency: _____

Date: 3/16/87

Distribution (by Agency preparing fiscal note):

- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

COMPUTING THE ALTERNATE ELF

The alternate Economic Limit Factor formula is:

$$\text{ELF} = (1 - \text{PEL}/\text{TP}) \text{EXP}[(55,000,000 * \text{WD}) / (\text{PEL} * \text{TP} / \text{Days})]$$

PEL (Production at the Economic Limit) =
 (300 barrels per day)*
 (average number of operating wells during the month)*
 (number of days of production for the month).

For example:

*300 barrels * 519 wells * 30 days = 4,571,000 barrels per month at the Economic Limit.*

TP (Total Production for the field) =
 (average number of operating wells during the month)*
 (number of days of production for the month)*
 (average daily production per well).

For example:

*519 wells * 30 days * 2750 barrels per well = 42,817,500 barrels of production per month.*

WD (Well Days) =
 (average number of operating wells during the month)*
 (number of days of production for the month).

For example:

*519 wells * 30 days = 15,570 well days.*

Days = the number of days in the month for which the tax is paid.

For example: In April, 30 days.

CALCULATION EXAMPLE

$$\text{Alternate ELF} = (1 - \text{PEL} / \text{TP}) \text{EXP}[(55,000,000 * \text{WD}) / (\text{PEL} * \text{TP} / \text{Days})]$$

$$(1 - 4,671,000/42,817,500) \text{EXP}[(55,000,000*15,570)/(4,671,000*42,817,500/30)]$$

$$= (1 - .1091) \text{EXP} (.1285)$$

$$= (.8909) \text{EXP} (.1285)$$

$$= .9856$$

FISCAL EFFECTS OF ELF ALTERNATIVES
Additional Revenue (Millions) At the 30th percentile

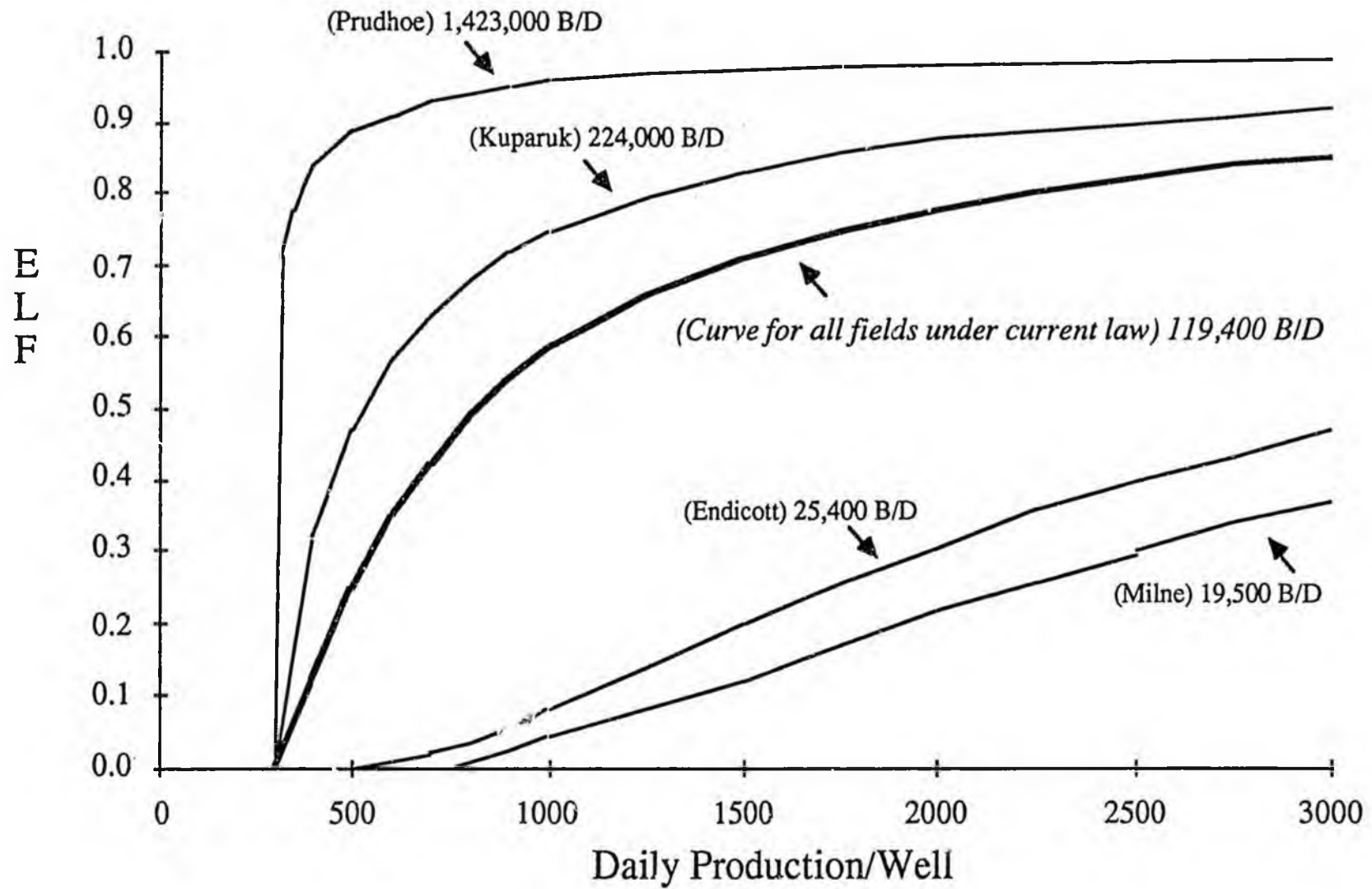
	HB	CSHB
	<u>164</u>	<u>154</u>
1987	0.0	0.0
1988	76.7	88.7
1989	92.0	108.5
1990	98.5	117.6
1991	99.9	112.9
1992	105.6	117.8
1993	5.7	129.1
1994	3.9	110.4
1995	3.7	102.1
1996	4.5	97.7
1997	3.7	100.4
1998	2.0	88.2
1999	-0.2	90.9
2000	-0.1	69.0

Source: DOR fiscal notes, 3/2/87 and 3/19/87.

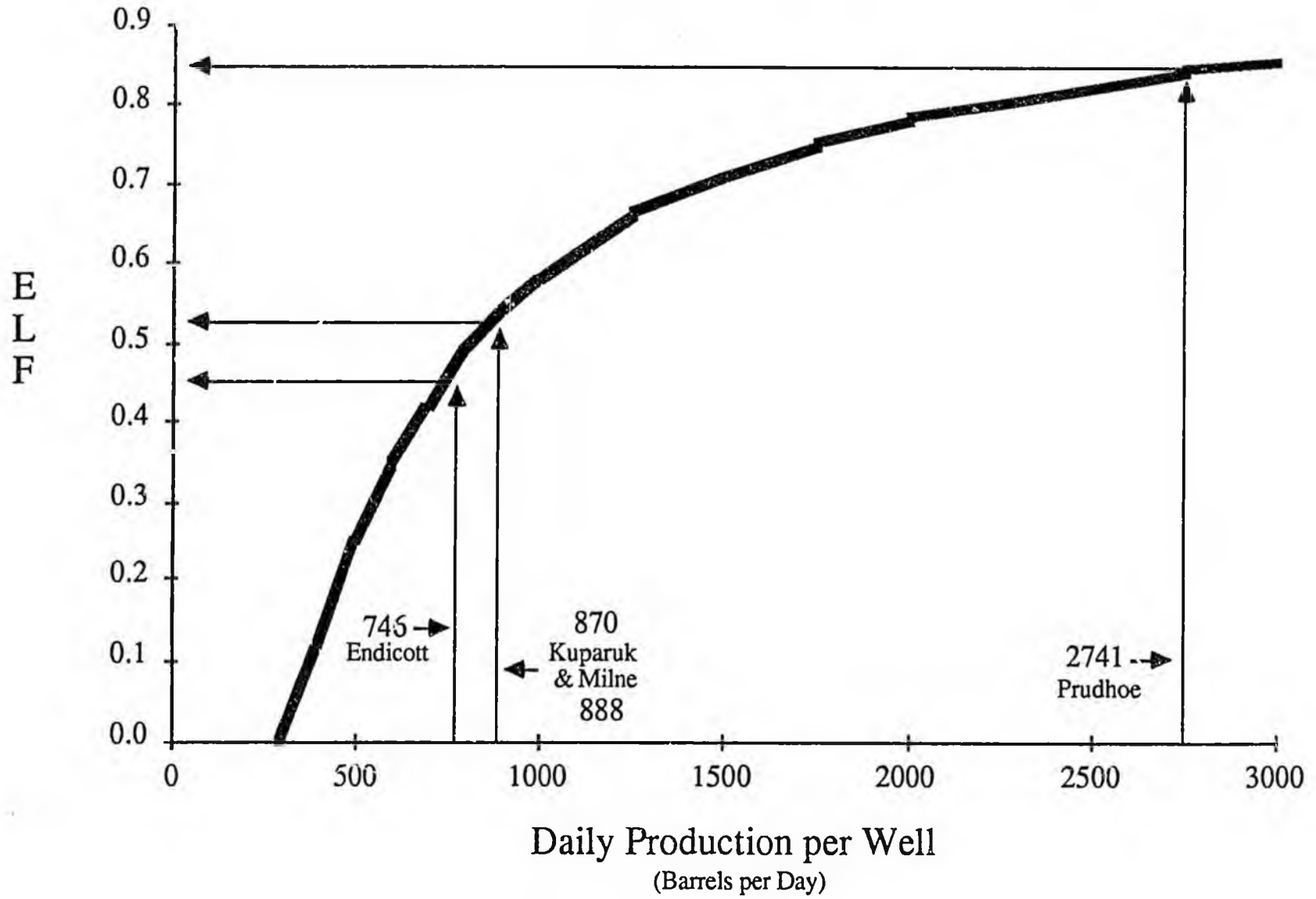
Prepared by OMB/Division of Policy, 3/20/85.

Alternate ELF

Constant At 55,000,000



Current Law



**STATE, FEDERAL AND INDUSTRY SHARES OF ALASKA OIL
RESOURCE INCOME: FISCAL 1982-1985**
(millions of dollars except as noted)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Fiscal year	Total Revenue	State Royalty	Sever. Conser. tax	Total Prop. tax	Total Oper. Costs	Total Deprec.	Total Acquis. Costs	Windfall Profits Tax
1982	\$16,456	\$1,553	\$1,581	\$276	\$940	\$602	\$1	\$2,018
1983	\$15,470	\$1,448	\$1,494	\$307	\$1,101	\$780	\$1	\$1,018
1984	\$14,955	\$1,409	\$1,393	\$358	\$1,259	\$998	\$1	\$412
1985	\$15,136	\$1,390	\$1,389	\$397	\$1,449	\$1,093	\$1	\$70

	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Fiscal Year	Uncap. Interest Expense	Explore. Costs	Admin. Costs	Other Deducs.	Total Deducs.	State Taxable Net Income	Corp. Petrol Income Tax	Federal Taxable Income
1982	\$721	\$191	\$236	\$149	\$8,268	\$8,188	\$669	\$7,519
1983	\$676	\$204	\$252	\$142	\$7,423	\$8,047	\$236	\$7,811
1984	\$614	\$219	\$265	\$136	\$7,064	\$7,891	\$265	\$7,626
1985	\$566	\$234	\$278	\$130	\$6,997	\$8,139	\$169	\$7,970

	[17]	[18]	[19]	[20]	[21]	[22]	[23]
Fiscal Year	Federal Corp. Income Tax	Oil Industry Alaska Profits	Total Federal Tax	Total State Tax & Royalty	----Share of Oil Income----		
					State	Federal	Industry
1982	\$2,098	\$5,421	\$4,116	\$4,079	30%	30%	40%
1983	\$2,140	\$5,671	\$3,158	\$3,485	28%	26%	46%
1984	\$2,242	\$5,384	\$2,654	\$3,425	30%	23%	47%
1985	\$2,343	\$5,627	\$2,413	\$3,345	29%	21%	49%

SOURCES AND FORMULAS --

Column [1]: Vincent Wright, chief of research, to Mary Nordale, Commissioner of Revenue, Memorandum of October 31, 1985, Table 3.

Columns [2] & [3]: January 1986 DOR Revenue Sources, p. 39.

Columns [4] to [12]: Vincent Wright, loc. cit.

Column [13]: sum of columns [2] through [12]

Column [14]: column [1] - column [13]

Column [15]: Revenue Sources, p. 39.

Column [16]: column [14] - column [15].

Column [17]: column [16] * (production-weighted average tax rate -- 1982 = .279; 1983 = .274; 1984 = .294; 1985 = .294). Company effective rates for '82-84 from R. McIntire and R. Folen, "Corporate Income Taxes in the Reagan Years," Oct. 1984, pp. 32-36; '85 estimated by OMB.

Column [18]: column [16] - column [17].

Column [19]: column [8] + column [17].

Column [20]: sum of columns [2], [3], [4], and [15].

Column [21]: (column [18])/(sum of columns [18], [19], and [20]).

Column [22]: (column [19])/(sum of columns [18], [19], and [20]).

Column [23]: (column [20])/(sum of columns [18], [19], and [20]).

Office of Management and Budget
Division of Strategic Planning
revised April 11, 1986

Production Impact of Expo55 (Million bbls/yr)

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore	Total
1987	0	0	.05	0	-.03	0	0	0	.02
1988	-1.97	-.32	.23	.65	-.05	0	0	0	-1.46
1989	-1.77	-.33	.37	2.16	-.06	0	0	0	.37
1990	-1.59	-.33	.39	2.13	-.07	0	0	0	.53
1991	-1.46	-.29	.39	2.1	-.1	0	0	0	.64
1992	-1.41	-.26	.36	2.01	-.1	0	.28	0	.88
1993	-1.25	-.23	.38	1.94	-.12	0	.51	0	1.23
1994	-2.59	-.38	.32	1.41	-.47	0	.53	0	-1.18
1995	-2.24	-.37	.29	1.69	-.41	-.63	.56	0	-1.11
1996	-2.16	-.3	.18	1.22	-.37	-.77	.48	0	-1.72
1997	-3.12	-.27	.19	.77	-.31	-1.13	.41	0	-3.46
1998	-2.57	-.16	.18	.41	-.28	-1.13	.38	.13	-3.04
1999	-2.18	-.1	.16	.06	-.21	-1.23	.58	.17	-2.75
2000	-1.93	-.07	.03	-.18	-.17	-1.23	.51	.18	-2.86
2001	-1.77	-.02	-.03	-.3	-.11	-1.26	.43	.21	-2.85
2002	-1.46	-.01	-.09	-.36	-.07	-1.32	.34	.23	-2.74
2003	-1.31	0	-.06	-.33	-.02	-1.12	.24	.23	-2.37
2004	-1.27	-.01	.01	-.34	-.02	-1.11	.22	.23	-2.29
2005	-1.13	-.04	-.03	-.26	-.04	-1.08	.18	.28	-2.12
Total	-33.18	-3.49	3.32	14.78	-3.01	-12.01	5.65	1.66	-26.28

THE EFFECT OF THE FIELD SIZE ELF ON THE PRODUCE BAY SEVERANCE TAX RATE

	Producing Wells	Production (Bbl/day)	Current ELF	New ELF Field Size Factor = 55000000	Current Effective tax Rate FY 1989	New Effective tax Rate FY 1989	Increased Effective tax Rate FY 1988
December DOR 1988 Mean	520	1510000	.0460	.9833	.1269	.1475	.0206

Sensitivity Table

500	1450000	.0458	.9863	.1269	.1479	.0211
	1500000	.0500	.9872	.1276	.1481	.0205
	1525000	.0532	.9876	.1280	.1481	.0202
	1550000	.0555	.9880	.1283	.1482	.0199
	1575000	.0577	.9884	.1287	.1483	.0196
520	1450000	.0399	.9857	.1260	.1479	.0219
	1500000	.0450	.9867	.1263	.1480	.0212
	1525000	.0475	.9871	.1271	.1481	.0209
	1550000	.0499	.9875	.1275	.1481	.0206
	1575000	.0522	.9879	.1278	.1482	.0204
540	1450000	.0539	.9851	.1251	.1478	.0227
	1500000	.0393	.9861	.1259	.1479	.0220
	1525000	.0418	.9866	.1263	.1480	.0217
	1550000	.0443	.9870	.1266	.1481	.0214
	1575000	.0467	.9874	.1270	.1481	.0211
550	200000	.0691	.2024	.0104	.0304	.0200
	225000	.1318	.3406	.0198	.0511	.0313
	250000	.1913	.4533	.0287	.0680	.0393
	275000	.2454	.5429	.0368	.0814	.0446
	300000	.2939	.6139	.0441	.0921	.0480

III. EFFECT OF THE FIELD SIZE ELI ON THE KUPARUK SEVERANCE TAX RATE

Producing Wells	Production (Bbl/day)	Current Elf	New ELF Field Size Factor = 55000000	Current Effective Tax Rate FY 1980	New Effective Tax Rate FY 1988	Increased Effective Tax Rate FY 1988
December 1980 Mean	260	.5299	.6569	.0795	.0985	.0191

Sensilivity table

250	200000	.4064	.6500	.0730	.0975	.0245
	225000	.5370	.7187	.0806	.1078	.0272
	250000	.5787	.7638	.0868	.1155	.0287
	275000	.6137	.8087	.0921	.1213	.0293
	300000	.6433	.8388	.0965	.1258	.0293
260	200000	.4686	.6357	.0703	.0953	.0251
	225000	.5206	.7069	.0781	.1060	.0279
	250000	.5636	.7601	.0845	.1140	.0295
	275000	.5996	.8006	.0899	.1201	.0301
	300000	.6302	.8319	.0945	.1248	.0303
270	200000	.4511	.6213	.0677	.0932	.0255
	225000	.5044	.6951	.0757	.1043	.0286
	250000	.5486	.7504	.0823	.1126	.0303
	275000	.5857	.7925	.0879	.1189	.0310
	300000	.6172	.8250	.0926	.1238	.0312
280	200000	.4350	.6069	.0651	.0910	.0260
	225000	.4884	.6833	.0733	.1025	.0292
	250000	.5337	.7406	.0801	.1111	.0310
	275000	.5718	.7843	.0858	.1176	.0319
	300000	.6043	.8181	.0906	.1227	.0321

THE EFFECT OF THE FIELD SIZE LIF ON THE MINE SEVERANCE TAX RATE

	Producing Wells	Production (Mb1/day)	Current LIF	New LIF Field Size Factor = 55000000	Current Effective Tax Rate FY 1988	New Effective Tax Rate FY 1988	Decreased Effective Tax Rate FY 1988
December DOR 1988 Mean	22	20000	.5411	.0074	.0663	.0011	-.0651

Sensitivity table

15	10000	.3928	0	.0490	0	-.0490
	15000	.5787	.0128	.0709	.0016	-.0693
	20000	.6765	.0267	.0829	.0118	-.0710
	25000	.7376	.2333	.0904	.0286	-.0618
	30000	.7724	.3704	.0955	.0454	-.0501
20	10000	.2454	0	.0301	0	-.0301
	15000	.4569	.0019	.0560	.0002	-.0557
	20000	.5787	.0380	.0709	.0047	-.0662
	25000	.6565	.1336	.0804	.0164	-.0641
	30000	.7102	.2557	.0870	.0313	-.0557
40	10000	0	0	0	0	0
	15000	.0040	0	.0104	0	-.0104
	20000	.2454	.0002	.0301	0	-.0300
	25000	.3669	.0083	.0449	.0010	-.0439
	30000	.4569	.0441	.0560	.0054	-.0506
60	10000	0	0	0	0	0
	15000	0	0	0	0	0
	20000	.0223	0	.0036	0	-.0036
	25000	.1420	.0001	.0174	0	-.0174
	30000	.2454	.0037	.0301	.0005	-.0296

THE EFFECT OF THE FIELD SIZE ELF ON THE ENDICOTT SEVERANCE TAX RATE

	Producing Wells	Production (Bbl/day)	Current LII	New ELF Field Size Factor = 55000000	Current Effective Tax Rate FY 1988	New Effective Tax Rate FY 1988	Decreased Effective Tax Rate FY 1988
December 1988 Mean	69	62500	.5397	.2227	.0661	.0275	-.0386

Sensitivity Table

50	40000	.4864	.1160	.0596	.0142	-.0454
	60000	.6433	.152	.0780	.0509	-.0279
	80000	.7275	.6214	.0891	.0761	-.0130
	100000	.7794	.7423	.0955	.0909	-.0045
	120000	.8149	.8155	.0978	.0999	.0001
75	40000	.2815	.0226	.0345	.0028	-.0317
	60000	.4864	.2378	.0596	.0291	-.0305
	80000	.6027	.4692	.0758	.0575	-.0164
	100000	.6765	.6267	.0829	.0768	-.0061
	120000	.7273	.7202	.0891	.0832	.0001
90	40000	.1785	.0058	.0219	.0007	-.0212
	60000	.3998	.1609	.0490	.0127	-.0293
	80000	.5319	.3892	.0652	.0477	-.0175
	100000	.6172	.5616	.0756	.0688	-.0068
	120000	.6765	.6775	.0829	.0830	.0001
110	40000	.0691	.0003	.0095	0	-.0094
	60000	.2937	.0072	.0360	.0107	-.0253
	80000	.4424	.2956	.0542	.0362	-.0180
	100000	.5411	.4799	.0663	.0588	-.0075
	120000	.6107	.6118	.0748	.0749	.0001

THE EFFECT OF THE FIELD SIZE ELF ON THE LISBURN SEVERANCE TAX RATE

	Producing Wells	Production (Bbl/day)	Current ELF	New ELF Field Size Factor = 5500000	Current Effective tax Rate FY 1988	New Effective tax Rate FY 1988	Decreased Effective tax Rate FY 1988
December 1988 Mean	20	35000	.7495	.2055	.1124	.0420	-.0694

Sensitivity table

20	25000	.6565	.1336	.0905	.0200	-.0704
	35000	.7495	.3734	.1124	.0560	-.0564
	50000	.8220	.6258	.1233	.0939	-.0294
	75000	.8800	.8156	.1320	.1223	-.0097
	100000	.9095	.8920	.1364	.1339	-.0025
35	25000	.4338	.0184	.0651	.0028	-.0623
	35000	.5787	.1544	.0868	.0232	-.0637
	50000	.6767	.4213	.1045	.0632	-.0413
	75000	.7735	.6916	.1190	.1037	-.0153
	100000	.8456	.8160	.1265	.1224	-.0041
50	25000	.2454	.0012	.0368	.0002	-.0366
	35000	.4240	.0533	.0636	.0080	-.0556
	50000	.5787	.2704	.0868	.0406	-.0462
	75000	.7102	.5796	.1065	.0869	-.0196
	100000	.7794	.7423	.1169	.1114	-.0056
100	25000	.0072	0	.0011	0	-.0011
	35000	.1695	.0023	.0254	.0003	-.0251
	50000	.3669	.0789	.0550	.0136	-.0414
	75000	.5536	.3896	.0830	.0584	-.0246
	100000	.6565	.6046	.0905	.0907	-.0070

PRESTON, THORGRIMSON, ELLIS & HOLMAN

420 L STREET - SUITE 404

ANCHORAGE ALASKA 99501

1907 276-1969

RECEIVED
Department of Law

MAY - 1 1986

AM PM
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MEMORANDUM

TO: Deborah Vogt

FROM: Joseph K. Donohue

DATE: April 28, 1986

RE: **Retroactive Amendments to ELF Factor**

You have requested an opinion concerning the constitutionality of enacting a bill which would retroactively either repeal, or amend the methodology for calculating, the economic limit factor under AS 43.55.013. Specifically, you have asked whether a bill enacted in February 1987 and made retroactive to January 1, 1987 would present any due process problem under the Fifth Amendment to the United States Constitution or under Article I, Section 7 of the Alaska Constitution.

The gross production tax on oil or gas is payable monthly. The tax is due on the 20th day of each month for oil or gas production which occurred during the preceding month. The tax is delinquent if not paid before the end of the month following the month of production. AS 43.55.020(a). Thus, the tax on January production is due on February 20 and is delinquent if not paid on or before February 28.

The economic limit factor is defined in AS 43.55.013 and the Department of Revenue has promulgated a number of regulations which interpret and implement of the provision. See 15 AAC 55.010-.040 and .090. The economic limit factor (ELF) is a concept which is designed to reduce the effective rate of taxation on a producing field as production from that field becomes increasingly marginal. The ELF is multiplied by the percentage-of-value amount set forth in AS 43.55.011(b) or the cents-per-barrel amount calculated under (c) to determine the tax due. AS 43.55.013(b) (2) and (3) provide that during the first 10 years of commercial production from a lease or property, an economic limit factor which is greater than .7 is deemed to be one for purposes of the calculation of tax liability. For example, for the period since 1981 when the .7 threshold was enacted as part of Ch. 116 SLA 1981, the ELF at Prudhoe Bay has been greater than .7 and, therefore, one. This, in turn, means that the ELF does not have any operative effect unless it is found to be less than .7 during the initial 10-year period. For Prudhoe Bay, the 10-year period expires in June 1987.

Page 2.
Deborah Vogt
April 28, 1986

The ELF is derived by the use of a rather complicated mathematical formula which in turn is based on certain simplifying assumptions. For oil, the monthly production rate at the economic limit is presumed to be 300 barrels times the number of well days for the lease or property during the month for which the tax is to be paid. AS 43.55.013(d).

The taxpayer may rebut this presumption at a formal hearing by providing clear and convincing evidence of a different monthly production rate. The determination of the monthly production rate at the economic limit is made by dividing the value at the point of production under AS 43.55.013(f) into the average monthly direct operating costs calculated under subsection (e). The hearing must be held before February 15 of a year or within 6 months after commencement of oil production from a lease or property. The results of the hearing "shall be used for all oil production during that calendar year from the lease or property." AS 43.55.013(d). Therefore, the statute expressly calls for an annual determination with some retroactive effect on the monthly tax period preceding the hearing on the appropriate monthly production rate. This procedural approach makes administrative sense since it is more efficient to have this potentially difficult issue decided on an annual basis rather than on a monthly basis.

Perhaps the leading case on the question of whether a tax statute can apply retroactively to previous tax periods is Welch v. Henry, 305 U.S. 134 (1938). There, the United States Supreme Court upheld a corporate income tax amendment enacted by Wisconsin in March 1935 which was applicable to receipt of corporate dividends in 1933. The court held that, except for a narrow category of gift taxation cases, the legislature had broad authority to adjust or amend tax liability retrospectively.

The exception to this rule mentioned by the court pertained primarily to instances where voluntary irrevocable actions of taxpayers (e.g., making a bequest) were impacted by the retroactive imposition of a tax. The Supreme Court stated that the critical part of the constitutional test was whether "the nature or amount of the tax could not reasonably have been anticipated by the taxpayer at the time of the particular voluntary act which the statute later made the taxable event." 305 U.S. at 147. The cases cited by the court, e.g. Nichols v. Coollidge, 274 U.S. 531 (1927), and Untermeyer v. Anderson, 276 U.S. 440 (1928), were instances where the donor might well not have acted as he did had he anticipated the tax. The court said that the facts of each case and the nature of the tax would have to be examined to determine if retroactivity gives rise to such harsh and oppressive results that it offends the Constitution. The court stated "there are other forms of taxation whose retroactive imposition cannot be said to be similarly offensive, because their incidence

is not on the voluntary act of the taxpayer." 305 U.S. at 147. The court specifically listed property taxes, income taxes and benefit assessments. 305 U.S. at 147-148. The Supreme Court also noted that it was historically the practice of Congress and the Wisconsin Legislature to enact revenue or tax legislation in a given year and to give it effect to the entire calendar year.

The United States Supreme Court more recently upheld the retroactive increase in the minimum tax on preferences in United States v. Darusmont, 449 U.S. 292 (1981). There, an amendment to the Internal Revenue Code enacted in October 1976 was applied to the entire 1976 tax year. In addition to relying on Welch v. Henry, *supra*, the Supreme Court cited its earlier decision in Cooper v. United States, 280 U.S. 409, 411 (1930), which upheld the taxation of gains from "prior but recent transactions." The Supreme Court also relied on the analysis of Judge Learned Hand in Cohan v. Commissioners, 39 F.2d 540, 545 (2d Cir. 1930). Judge Hand, in resolving a similar issue involving retroactivity of a tax, held that nobody had a vested right in the rate of taxation. In responding to the question of whether the tax law change was foreseeable, Judge Hand stated that once a system of taxation is already in place, a taxpayer "must be prepared for such possibilities" 39 F.2d at 545.

Other decisions which uphold tax law changes with arguably retroactive impacts in the face of due process challenges include Buttke v. Commissioner, 625 F.2d 262 (8th Cir. 1980) (involving the same minimum tax amendments subsequently upheld by the U.S. Supreme Court in United States v. Darusmont, *supra*) and Neild v. District of Columbia, 110 F.2d 146, 153 (D.C. Cir. 1940) (involving the constitutionality of the application of a new gross receipts tax measured by the prior year's receipts).

Sometimes retroactive tax laws are challenged under state constitutional provisions barring retrospective laws per se or interference with vested rights. The analytical approach taken by the courts is substantially similar. Under the first line of cases, tax bills which are applied to the entire calendar year in which they are enacted are generally found not to be retrospective in operation. See, e.g., Martin v. Board of Assessment Appeals, 707 P.2d 348 (Colo. 1985). In the Martin case, a law changing the factors to be considered in appraising condominiums which took effect in May 1982 and which was used to assess property values as of January 1, 1982 was upheld. The court held that to find an unconstitutional retrospective effect required a showing of an impairment of a vested right. The court concluded:

Page 4.
Deborah Vogt
April 28, 1986

... [P]roperty owners have no vested right to have their taxable property assessed by particular methods employed in prior years. ... Since the statute only alters the factors which may be considered in determining actual value, it does not impair the taxpayers' vested rights, and therefore is not unconstitutionally retrospective in its operation. 707 P.2d at 352.

A "vested rights" challenge in the context of a severance tax increase led to an identical conclusion. In Belco Petroleum v. State Board of Equalization, 587 P.2d 204 (Wyo. 1978), a 1975 amendment to the state severance tax increased the amount of tax due for the previous year. Under the Wyoming severance tax, a taxpayer paid his 1974 tax in July 1975 computed on the value of gross production for previous year. In upholding the application of the 1975 increase to the July assessment, the court ruled that such an increase was not retrospective but merely called for a tax measured by or computed on the basis of antecedent facts or transactions. The court also found that there was no vested right in a specific tax rate.

On the basis of the foregoing state and federal cases, one can conclude that there is no vested right in a particular tax rate or in a particular method of determining a tax liability. The U.S. Supreme Court cases focus on whether the transaction was taxable during the period of retroactive coverage and whether said period is reasonable, whether the transactions were "prior but recent" in time with respect to the tax law change, whether the change was reasonably foreseeable and whether or not the taxpayer might have voluntarily acted as he did had he but known of the change.

The question before us involves the proposed repeal or modification of the ELF factor in February 1987, effective January 1, 1987. The retroactive period is at most two months. It would adjust a factor which is determined on an annualized calendar basis under present law. The affected taxpayers are those whose decision to invest and produce oil or gas has already been made and whose production is already subject to taxation. In the State of Alaska, amendments to the oil and gas production tax must certainly be viewed as foreseeable. In fact, the Legislature has discussed and debated changes to the ELF factor during the 1986 legislative session. Under these circumstances, I conclude that neither state nor federal due process limitations would be abrogated by the repeal or amendment of the ELF factor under consideration here. Furthermore, under the analyses set forth in Martin and Belco Petroleum above, a change in the tax rate or ELF methodology prior to February 20, 1987 might not even be viewed as having "retrospective" operation.

147.JKD:ls

STATE OF ALASKA
THE LEGISLATURE

POUCH Y STATE CAPITOL
JUNEAU, ALASKA 99801
307 465 3900

LEGISLATIVE AFFAIRS AGENCY

MEMORANDUM

March 17, 1987

SUBJECT: Retroactivity of proposed committee substitute
(CSHB 164(Resources))

TO: Representative Sam Cotten
Chair, House Resources Committee

FROM: Theresa L. Bannister *TB*
Legislative Counsel

This memo accompanies the committee substitute that you have requested for HB 164, a bill relating to the oil and gas properties production tax. That bill includes a provision that would make the bill retroactive to January 1, 1987.

Please be aware that the retroactivity provision may violate federal and state constitutional provisions against enacting ex post facto laws (art. I, sec. 15 of the Constitution of the State of Alaska; art. I, sec. 9, cl. 3 of the U.S. Constitution). In this instance, the tax is incurred and remitted on a monthly schedule. AS 43.55.020. Therefore, the taxpayers under the chapter will have already paid or become obligated to pay an amount certain for the months of January, 1987, through the month before the month of enactment.

You may wish to make the bill retroactive to the beginning of the month in which the bill takes effect. That would not create retroactivity problems since the tax liability would not have become due yet.

If I may be of further assistance, please advise.

TLB:mkr
m10/011

Enclosure

HB 23

Recommending do pass (3): Boucher (Chairman), Hudson, Ulmer
No recommendation (2): Pettyjohn, Collins

A zero fiscal note with analysis was published March 4, 1987.

HB 23 was referred to the Labor & Commerce Committee.

INTRODUCTION OF CITATIONS

The following citation was received:

Honoring Fielson Ravens Boys Basketball Team,
Class AAA State Basketball Champions
by Representative Miller and Senator Coghill

The citation was referred to the Rules Committee for placement on the calendar.

INTRODUCTION, FIRST READING AND REFERENCE
OF HOUSE RESOLUTIONS

HCR 14

HOUSE CONCURRENT RESOLUTION NO. 14 by Taylor:

Relating to training of police officers.

was read the first time and referred to the State Affairs and Finance Committees.

INTRODUCTION, FIRST READING AND REFERENCE
OF HOUSE BILLS

HB 160

HOUSE BILL NO. 160 by Boucher and Davison, entitled:

"An Act establishing the Commission on the Future of the Permanent Fund; providing for public testimony on the use that should be made of the income and principal of the permanent fund; and providing for an effective date."

was read the first time and referred to the State Affairs, Judiciary and Finance Committees.

HB 161

HOUSE BILL NO. 161 by Taylor, Phillips and Zawacki, entitled:

"An Act authorizing an advisory vote on the permanent fund dividend program and on imposition of an income tax on individuals."

was read the first time and referred to the State Affairs, Judiciary and Finance Committees.

HB 162

HOUSE BILL NO. 162 by Ulmer, Hudson, Taylor and Pearce, entitled:

"An Act relating to work in underground mines and workings."

was read the first time and referred to the Labor & Commerce and Judiciary Committees.

HB 163

HOUSE BILL NO. 163 by Goll, entitled:

"An Act relating to advisory elections on certain annexation proposals."

was read the first time and referred to the Community & Regional Affairs and Finance Committees.

HB 164

HOUSE BILL NO. 164 by the Rules Committee by request of the Governor, entitled:

"An Act relating to the oil and gas properties production tax; and providing for an effective date."

was read the first time and referred to the Resources and Finance Committees.

A fiscal note was published March 4, 1987.

The Governor's transmittal letter, dated March 3, 1987, appears below:

"Dear Representative Gruasendorf:

Under the authority of art. III, sec. 18, of the Alaska Constitution, I am transmitting a bill relating to the oil and

HB 164

gas properties production tax. The primary effect of the bill is to postpone the application of the "true" economic limit factor (ELF) to the Prudhoe Bay field. The bill also amends the economic limit factor provisions applying to all oil fields so that the ELF is not sensitive to changes in the value of oil.

Existing AS 43.55.011(a) provides that an oil producer must calculate its production (severance) tax by multiplying the nominal rate calculated under AS 43.55.011(b) and (c) by the economic limit factor determined under AS 43.55.011. The ELF is a formula that has the effect of reducing the severance tax rate. In 1981, the legislature made several changes in oil and gas taxes: the income tax was changed to substitute modified apportionment for separate accounting; the nominal rate of the severance tax was increased for some fields; and the application of the ELF to a lease or property with an ELF of more than .7 was suspended until after that lease or property had been in commercial production for 10 years. Ch. 116, SLA 1981. Suspension of application of the ELF was accomplished by providing that, if the ELF was more than .7, then the ELF was considered to be "one." AS 43.55.013(b)(3). Thus, when multiplying the severance tax rate by the ELF, the full amount of the tax is the product.

Only the Prudhoe Bay and Lisburne fields currently have an ELF greater than .7. The Lisburne ELF is expected to fall below .7 after fiscal year 1988, but the Prudhoe Bay ELF is expected to remain about .7 for a number of years. Prudhoe Bay will have been in production for 10 years in June, 1987; thus, absent an amendment to AS 43.55.013(b)(3), the "true" ELF, as calculated under AS 43.55.013(b)(1), will begin to apply to that field at that time.

The fiscal note on the 1981 legislation did not include projections beyond FY 1985, but an analysis by the Legislative Finance Division showed that application of the "true" ELF provision would cause state revenue to fall precipitously in FY 1988. Governor Hammond noted this possibility, but expressed "full confidence in the ability of the legislature to deal at that time" with adverse revenue consequences, should they prove to be serious. Statement of Governor Hammond on signing FCCSSB 524 (ch. 116, SLA 1981); see July 27, 1981 press release on oil and gas legislation, fourth page.

Application of the "true" ELF to Prudhoe Bay would result in serious consequences for the state in the coming fiscal year: state severance collections would be reduced by over 15 percent, and FY 1988 revenue would fall by \$93,000,000 (already accounted for in the official "mean" forecast). Section 1 of the attached bill would prevent this precipitous decline in revenue by amending AS 43.55.013(b)(3) to delay the applicability of the true ELF to Prudhoe Bay for an additional five years. Section 1 of the bill also makes a conforming amendment to AS 43.55.013(b)(2) and (4). So

HB 164

long as the "true" ELF does not apply, the severance tax rate will be the full 15 percent of value, or \$.80 a barrel, whichever is greater, subject to the adjustment in AS 43.55.012.

The bill also changes the ELF provisions for all oil fields to remove the sensitivity of the ELF to price fluctuations. An element of the ELF calculation is the "PEL," or "production at the economic limit." The PEL represents the number of barrels a producer must produce in order to recover the costs of production. Currently, the PEL is presumed to be 300 barrels per well per day, but the taxpayer may rebut this presumption at a hearing before the Department of Revenue. At the hearing, the PEL could be calculated by dividing the cost of production into the value of the oil. AS 43.55.013(d). If the price of oil drops, the producer may be able to prove an entitlement to a PEL in excess of 300 barrels; if so, the ELF for that producer will go down. Thus, if prices fall drastically, the state loses severance tax revenue not only because the severance tax is applied against a lower value of oil, but also because the severance tax rate itself goes down as the result of a PEL hearing. Earlier in 1986, because of low prices, we were faced with the possibility that the state might suffer from this double reduction in severance tax revenue.

Section 2 of the attached bill deals with that problem by repealing the portion of existing law that provides for a hearing to change the PEL. The PEL is then simply set at 300 barrels per day. As a result, the ELF will be sensitive to changes in the amount of production, but will no longer be sensitive to fluctuations in price or the costs of production. Section 3 of the bill repeals two subsections in AS 43.55.013 dealing with the two elements of the hearing: costs and values. These changes do not apply to the production of gas.

I urge your early consideration and passage of this bill.

Sincerely,

/s/

Steve Cowper
Governor"

HB 165

HOUSE BILL NO. 165 by the Rules Committee by request of the Governor, entitled:

"An Act amending an appropriation to the Alaska Power Authority for the Bradley Lake Hydroelectric Project; and providing for an effective date."

was read the first time and referred to the Resources and Finance Committees.

**STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE**

REQUEST: _____

Bill Version : _____

Publish Date : _____

Revision Date: _____

Title: An Act Relating to the Oil and Gas Properties Production Tax

Agency Affected : Revenue

BRU: _____

Sponsor: Rules/Governor

Requestor: Rules

Components : _____

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING						
CAPITAL						
REVENUE		76,730.0	91,950.0	98,480.0	99,850.0	105,610.0

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 ANALYSIS

Vincent Wright

Prepared by : Chuck Logsdon
Division : Revenue/Research

Phone : 276-5364
Date : March 2, 1987

Approved by Commissioner : Hugh Malone
Agency : Department of Revenue

Date : 3/2/87

Distribution (by preparer) :

- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

MEMORANDUM

STATE OF ALASKA

Department of Revenue

Petroleum Research Section

February 27, 1987

To: Vincent D. Wright, Chief of Research

From: Charles Logsdon, Petroleum Economist

Chop

Subject: More ELF

Per your request, I have examined the revenue and production impact of extending the 10 year period during which the ELF is subject to the .7 or greater test to 15 years and fixing the value of the Production at the Economic Limit (PEL) at 300 barrels per well per day. Prudhoe Bay and Lisburne are the fields currently producing with a calculated ELF greater than .7 and thus would be directly impacted by this change in the State severance tax law. On average, the calculated ELF for Prudhoe is not expected to fall below 0.7 over the next 5 years. We expect the Lisburne ELF to fall below 0.7 in FY 1989 and subsequent years.

By setting the PEL at 300, the ELF no longer would be sensitive to the price of oil or the cost of producing oil and would be totally dependent on per barrel productivity for a producing lease or property. Over the next 5 years as Prudhoe Bay production begins to decline the only reason for an ELF less than 0.7 would be if a significantly greater than expected number of additional wells were drilled. For example we currently expect Prudhoe to produce on average, 0.984 million barrels per day in 1992 from 465 wells providing an ELF of .7911. If this same amount of oil were produced from 705 wells, the ELF would be equal to .6906.

The following tables illustrate the revenue impact and production impact of extending the ELF time line to 15 years and fixing the value of PEL at 300. These results are generated by the DOR revenue simulation model using the December 1986 input assumptions. The most significant result other than the revenues generated is that there is almost no average expected effect on North Slope production.

Revenue Impact of Extend5 (Million \$)

Fiscal Year	Delta 30%	Delta Mean
1987	0	0
1988	76.73	96.26
1989	91.95	118.06
1990	98.48	128.33
1991	99.85	132.92
1992	105.61	139.09
1993	5.73	7.3
1994	3.9	7.64
1995	3.66	6.56
1996	4.55	5.28
1997	3.67	5.55
1998	2.01	3.91
1999	2.53	2.62
2000	-.16	2.08
2001	-.1	2.79
2002	-.82	2.68
2003	-.73	2.28
2004	.53	2.1
2005	.49	1.87

Production Impact of Extend5 (Million bbls/yr)

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore	Total
1987	0	0	0	0	-.01	0	0	0	-.01
1988	-.77	-.12	-.04	-.02	-.02	0	0	0	-.97
1989	-.69	-.12	-.07	-.04	-.03	0	0	0	-.95
1990	-.6	-.12	-.11	0	-.03	0	0	0	-.86
1991	-.57	-.11	-.15	-.03	-.05	0	0	0	-.91
1992	-.52	-.1	-.15	-.06	-.05	0	0	0	-.88
1993	-.49	-.09	-.14	-.06	-.06	0	0	0	-.84
1994	-.44	-.11	-.14	-.04	-.07	0	0	0	-.8
1995	-.39	-.07	-.09	-.05	-.05	0	0	0	-.65
1996	-.35	-.06	-.12	-.05	-.05	0	0	0	-.63
1997	-.32	-.08	.01	-.04	-.06	0	0	0	-.49
1998	-.43	-.05	.03	-.03	-.09	0	0	0	-.57
1999	-.25	-.04	.02	-.01	-.02	0	-.02	0	-.32
2000	-.22	-.03	-.02	-.01	-.03	0	-.02	0	-.33
2001	-.2	-.03	.02	0	-.02	0	-.02	0	-.25
2002	-.18	-.02	.01	0	-.02	0	-.02	0	-.23
2003	-.16	-.01	-.01	0	-.01	0	-.01	0	-.2
2004	-.19	0	.04	0	-.01	0	-.01	0	-.17
2005	-.13	.01	.04	0	0	0	-.01	0	-.09
									0
									0
Total	-6.9	-1.15	-.87	-.44	-.68	0	-.11	0	-10.15



Official Business

Alaska State Legislature

House

P.O. BOX V
State Capitol
Juneau, Alaska 99811

TO: Rep. Sam Cotten, Co-Chair
Rep. Adelheid Herrmann, Co-Chair
Resources Committee members.
FROM: Ned Farquhar, staff *Ned Farquhar*
SUBJECT: Proposed CSHB 164 (Res)
DATE: March 18, 1987

Attached is a proposed committee substitute for HB 164 which will be presented at today's joint Resources-Finance hearing by Rep. Sund. Administration representatives will be present to explain the import of the changes described below.

Section 1 of the bill repeals the existing ELF formula and the ten-year moratorium provision for certain fields, and reinstates a new ELF formula based on the production of fields rather than wells.

Section 2 eliminates the opportunity for a producer to attempt to rebut the presumption that the PEL (production at the economic limit) is 300 bpd.

Section 3 repeals existing law that relates to the PEL rebuttal and hearing provision, eliminated in Section 2.

Section 4 makes the bill retroactive. There is some question as to the constitutionality of this section because tax payments have already been made, on a monthly basis, under existing law.

Section 5 establishes an immediate effective date for the bill.

cc: Finance Committee members and staff

w01257hcB
Bannister
3/17/87

Original sponsor: Rules/Governor

1 IN THE HOUSE

BY THE RESOURCES COMMITTEE

2 CS FOR HOUSE BILL NO. 164 (Resources)

3 IN THE LEGISLATURE OF THE STATE OF ALASKA

4 FIFTEENTH LEGISLATURE - FIRST SESSION

5 A BILL

6 For an Act entitled: "An Act relating to the oil and gas properties pro-
7 duction tax; and providing for an effective date."

8 BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

9 * Section 1. AS 43.55.013(b) is repealed and reenacted to read:

10 (b) The economic limit factor for oil production of a lease or
11 property shall be computed according to the following formula:

12
$$(1 - \{PEL/TP\}) \exp \{([55,000,000 \times WD] / [PEL \times TP / \text{Days}])\}$$

13 where: PEL = the monthly production rate at the economic limit;

14 TP = the total production during the month for which the tax
15 is to be paid;

16 WD = the total number of well days in the month for which
17 the tax is to be paid;

18 Days = the number of days in the month for which the tax is to
19 be paid; and

20 wher

21 * r

1 A LEASE OR PROPERTY. THE MONTHLY PRODUCTION RATE AT THE ECONOMIC
2 LIMIT FOR THE LEASE OR PROPERTY BASED UPON THE CLEAR AND CONVINCING
3 EVIDENCE OF THE TAXPAYER SHALL BE CALCULATED BY DIVIDING THE VALUE
4 DETERMINED UNDER (f) OF THIS SECTION INTO THE AVERAGE MONTHLY DIRECT
5 OPERATING COST DETERMINED UNDER (e) OF THIS SECTION AND SHALL BE USED
6 FOR PURPOSES OF THIS SECTION FOR ALL OIL PRODUCTION DURING THAT CALEN-
7 DAR YEAR FROM THE LEASE OR PROPERTY.]

8 * Sec. 3. AS 43.55.013(e) and (f) are repealed.

9 * Sec. 4. Sections 1 - 3 of this Act are retroactive to January 1,
10 1987.

11 * Sec. 5. This Act takes effect immediately under AS 01.10.070(c).
12
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23

1 IN THE HOUSE

BY THE RULES COMMITTEE BY
REQUEST OF THE GOVERNOR

2 HOUSE BILL NO.

3 IN THE LEGISLATURE OF THE STATE OF ALASKA

4 FIFTEENTH LEGISLATURE - FIRST SESSION

5 A BILL

6 For an Act entitled: "An Act relating to the oil and gas properties pro-
7 duction tax; and providing for an effective date."

8 BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

9 * Section 1. AS 43.55.013(b)(1) is repealed and reenacted to read:

10 (b)(1) The economic limit factor for oil production of a lease
11 or property shall be computed according to the following formula:

$$(1 - [PEL/TP]) \exp ([55,000,000 \times WD] / [PEL \times TP / \text{Days}])$$

12 where: PEL = the monthly production rate at the economic limit;

13 TP = the total production during the month for which the tax
14 is to be paid;

15 WD = the total number of well days in the month for which the
16 tax is to be paid;

17 Days = the number of days in the month for which the tax is to
18 be paid; and
19

20 Where "exp" indicates that the expression following it is an exponent.

21 * Sec. 2. Section 1 of this Act is retroactive to January 1, 1987.

22 * Sec. 3. This Act takes effect immediately under AS 01.10.070(c).

23 1) also add see 2 from HB 167
24 2) need to repeal the existing ten-year
25 petroleum in LRF (1982-83).
26
27 IV well A-AT
28
29

FISCAL EFFECTS OF ELF ALTERNATIVES
 Additional Revenue (Millions) At the 30th percentile

	<u>FY 87-88</u>	<u>FY 89</u>	<u>FY 90</u>	<u>FY 91</u>	<u>FY 92</u>
HB-164	76.7	92.0	98.5	99.9	105.6
Proposed CSHB-164 (Res.)*	98.6	98.1	109.6	96.1	94.2

*Indicates provisional OMB estimate pending DOR fiscal analysis due next week.

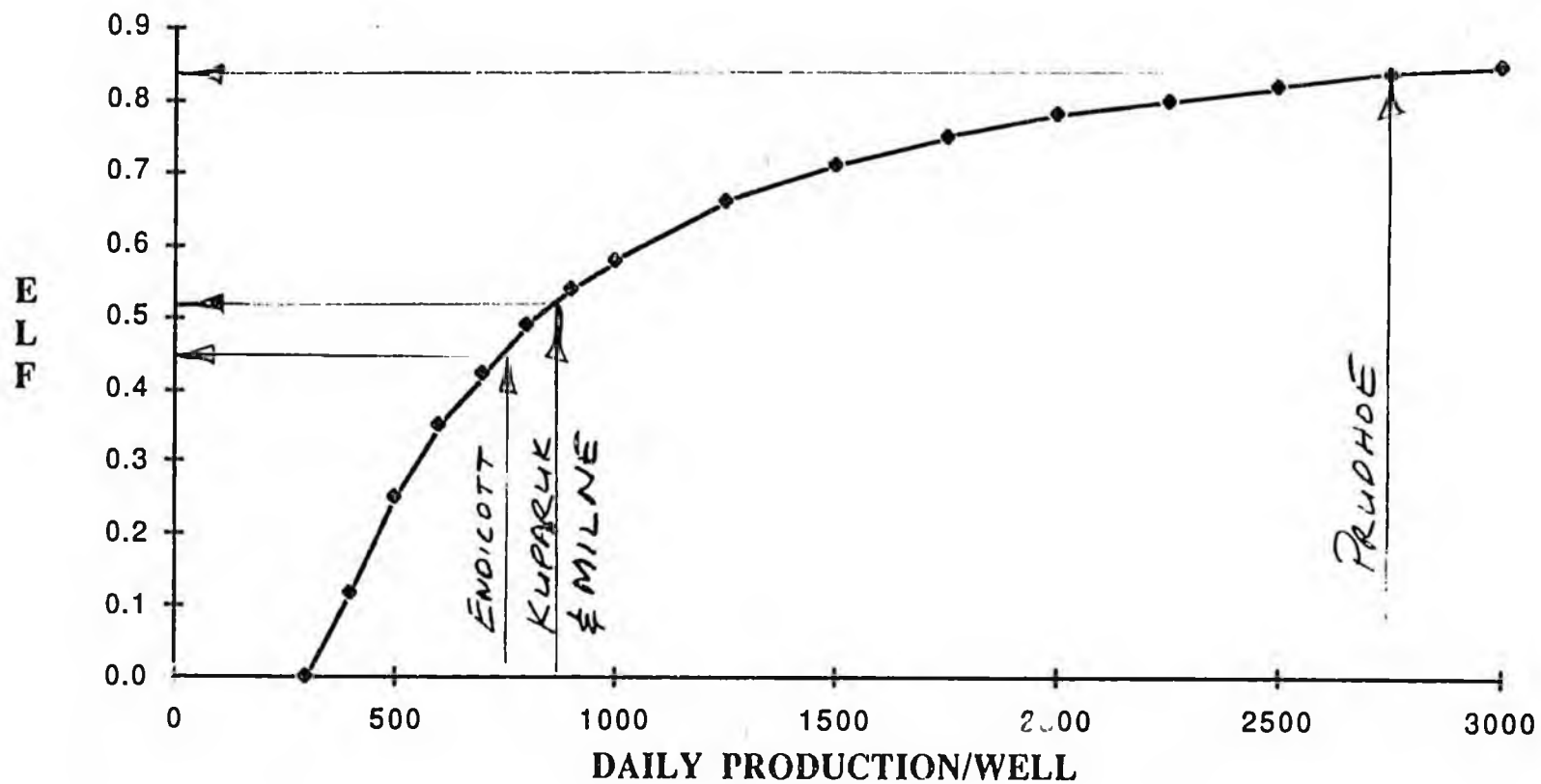
ESTIMATED SEVERANCE TAX RATES*

	<u>Prudhoe Bay</u>	<u>Kuparuk River</u>	<u>Milne Point</u>	<u>Endicott</u>	<u>Lisburne</u>	<u>McArthur River</u>	<u>Granite Point</u>
Current Law	12.6%	7.8%	6.5%	5.6%	12.3%	1.1%	1.3%
HB-164	15.0%	7.8%	6.5%	5.6%	12.3%	1.1%	1.3%
Proposed CSHB-164 (Res.)	14.8%	10.7%	0.3%	0.3%	3.6%	0.0%	0.0%

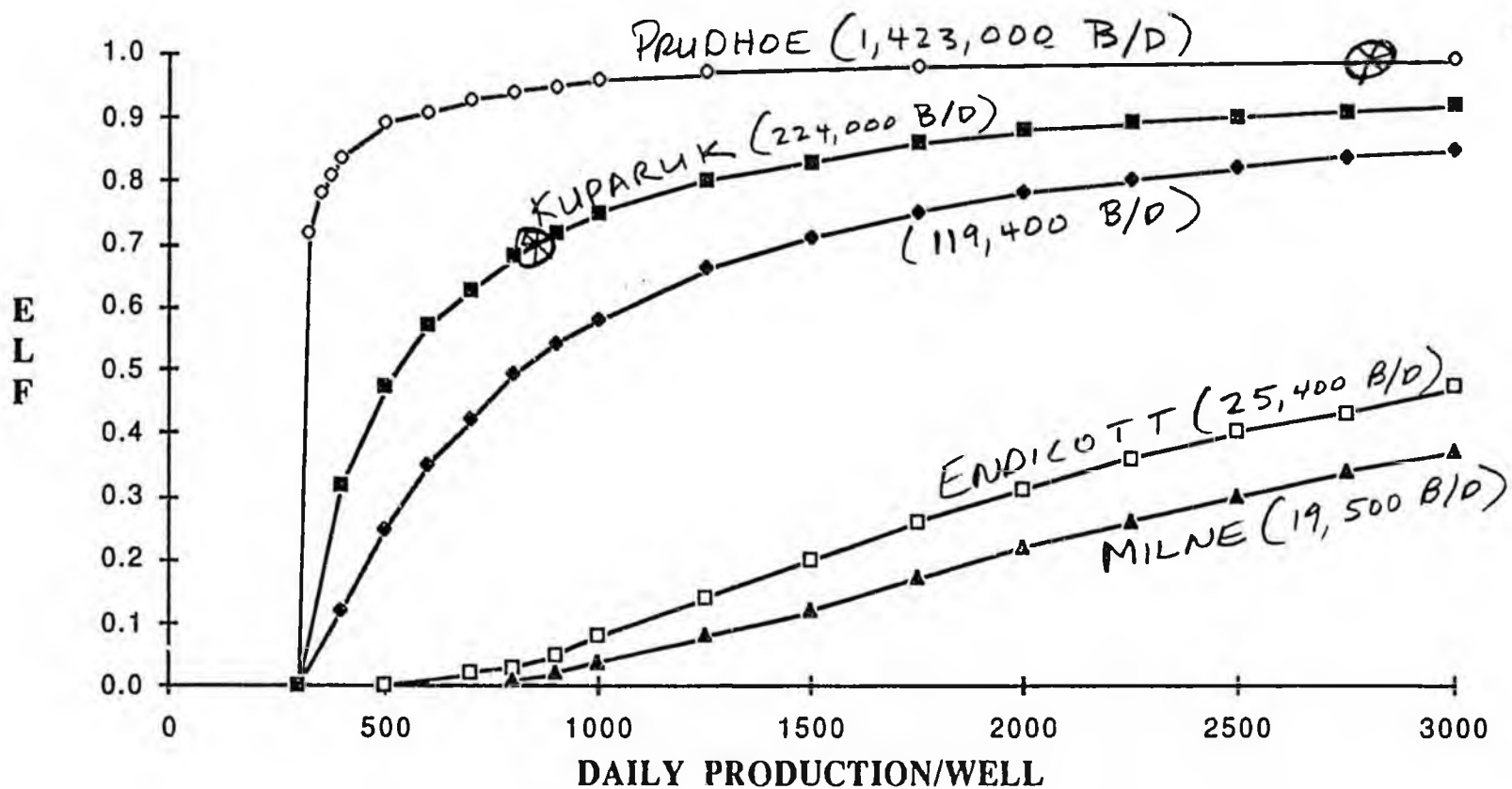
*North Slope values are forecast FY 88 averages; Cook Inlet values are estimated Dec 1986 rates;
 Cook Inlet fields not listed have zero effective rates under all alternatives.

OMB, Division of Policy, 3/18/87

CURRENT LAW



ALTERNATE ELF



DEPARTMENT OF
REVENUE

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ALASKA TAX VALUE
"ATV"

PETROLEUM TAX PRICING
INFORMATION EXCHANGE

STATE OF ALASKA
UNITED KINGDOM
NORWAY

MAY 17-20, 1988

April 8, 1988

Meetings in Europe
Oil Tax Reference Price System

Legislative Itinerary

Saturday, May 14, 1988

12:25 p.m. Depart Anchorage British Airways

Sunday, May 15, 1988

6:05 a.m. Arrive London
(Rest and Recuperation from Jet Lag)

Monday, May 16

Unscheduled

Tuesday, May 17

9:00 a.m. Ms. Margaret Hill, Ms. M.E. Williams
Inland Revenue
Oil Taxation Office
Melbourne House
Aldwych
London, WC2B 4LL

7:00 p.m. Dinner, guests of British Petroleum

Wednesday, May 18

9:00 a.m. Meeting with officers, British Petroleum
Britannica House

lunch Glavaal + P. Jensen
2:00 p.m. Depart London British Airways
4:55 p.m. Arrive Oslo

Thursday, May 19

9:00 a.m. Mr. Kjell Eikland
Oil and Gas Group
Norsk Hydro
N-1321 Stabekk
Oslo, Norway

Friday, May 20

9:00 a.m. Mr. Odd Sverre Haraldsen
Director
Energy Policy Department
Royal Ministry of Petroleum and Energy
Tollbugaten 31
Oslo, Norway

→ 3 Ploccasgate
Oslo 1, Norway

Saturday, May 21

8:15 a.m.
9:25 a.m.
12:15 p.m.
12:10 p.m.

Depart Oslo
Arrive London
Depart London
Arrive Anchorage

British Airways

TABLE OF CONTENTS

INTRODUCTION

MEMO TO UNITED KINGDOM AND NORWAY
INCLUDING PROPOSED AGENDA

MEMO FROM UNITED KINGDOM REGARDING
THE PETROLEUM REVENUE TAX:
VALUATION AND PRICING
INCLUDING THE FINANCE ACT OF 1987

INTERNAL MEMOS REGARDING
OIL TAX POLICY IN
UNITED KINGDOM AND NORWAY

PETROLEUM RENT COLLECTION
AROUND THE WORLD (excerpts)
by Alexander Kemp

AS 43.55
15 AAC 55

INTRODUCTION

In November 1987 within the Oil and Gas Audit Division the "ATV" was conceptualized. ATV is the acronym for the Alaska Tax Value or Alaska's idea of a tax reference price. Alaska is not unlike the United Kingdom or Norway or any of the petroleum producing countries in that it attaches a value to its crude oil for purposes of royalty and taxes. The OPEC nations set the value of OPEC oil at a "posted price." This price may or may not be indicative of actual market prices, and many times is not.

Alaska, however, has historically affixed its royalty, income and production taxes on the value or receipts for its crude oil in the market place. Controversy over the administration of Alaska's statutes and contracts centers around the components of value with protracted litigation between the State of Alaska and oil producers becoming all too often the outcome of disputed values.

The ATV promises to avert protracted litigation and concurrently establish a value for royalty and tax purposes that will withstand scrutiny while promulgating certainty and equitable administration. To this end, policy makers within the Department of Revenue polled other oil producing nations to gain insight into their valuation processes. As questions were posed, it became evident that two countries, the United Kingdom and Norway, approach the establishment of value of their crude oil in two very different and functional manners; the United Kingdom establishes for PRT (petroleum revenue tax) purposes a weighted average of arm's length sales in an applicable market whereas Norway appears to establish by committee a "norm" price.

To this end, contacts were made with government officials in both the United Kingdom and Norway with the intent of establishing a dialogue regarding oil production pricing. This dialogue begins May 17-20, 1988 in face to face meetings to gain insight into the methodologies utilized by both countries in approaching the valuation process.

ALASKA TAX VALUE

OBJECTIVES

1. Accelerate the Audit Program
2. Provide Current Tax Value
3. Reduce Taxpayer Conflict
4. Obtain Current Market Data for Forecasting
5. Reduce Cost of Tax Administration

ALASKA TAX VALUE

CONCEPTS

1. Market price is established by using volume weighted average of all arms length transactions during the tax period.
2. Market price is established for two markets:
 - (a) West Coast
 - (b) Gulf and East Coast
3. A single market price is established for each market for all taxpayers.
4. Prevailing value is the net back value at point of production.
5. An average marine transportation cost is established for each market from each shipping point.

ALASKA TAX VALUE

ACTION PLAN

1. Develop proposed regulations under AS 43.55.
2. Distribute regulations to producers for comment.
3. Develop proposed statute changes under AS 43.55.
4. Distribute statute changes to producers for comment.
5. Develop a plan for informing the public of changes.

April 19, 1988

Background

Petroleum revenues accounted for \$1.5 billion to the State of Alaska in 1987, 79 percent of total State revenues. These took the form of severance taxes, royalties, corporate income taxes, property taxes, bonuses, rents, and intergovernmental receipts. Of these, 80 percent were derived from either severance taxes or royalties.

Nearly all revenues accrue from the North Slope. Alaska North Slope crude oil (ANS) is produced and transported thousands of miles by pipeline and tanker to oil markets on the West, Gulf of Mexico, and East coasts of the United States, before a deemed or actual sale occurs. There is no single market area into which the oil is shipped and there is no representative market or fixed price. The markets are separate and function independently of each other. Further, the oil that arrives at these markets is either sold to third parties, exchanged with other companies for oil to be delivered elsewhere, or processed at the producers own refineries. Tax administration in such an environment has been difficult.

As a solution to this dilemma, we have developed the concept of the Alaska Tax Value (ATV), which is similar to the "market price" or "norm price" employed in your jurisdiction. Thus, we felt it would be fruitful to discuss the nuances of implementation with you.

The following is a brief description of our existing statutes, an outline of our proposed Alaska Tax Value, and a suggested meeting agenda.

Alaska Production Tax Statute

Generally, the Alaska production tax for oil is 12.25 percent of the gross value at the point of production produced prior to June 30, 1981, and 15 percent of the gross value at the point of production after June 30, 1981. This tax is reported to the Department of Revenue on monthly returns. The gross value at the point of production is the value of the oil at the point it is metered or measured in a condition of pipeline quality on the premises from which it is removed. In the case of Alaska North Slope (ANS), all this is at Pump Station One of the Trans-Alaska Pipeline System. Because there is so little oil sold at that point, a "netback" computation is used for determining value. This involves establishing a sales price at the point of delivery and deducting the actual cost of transportation through the Trans-Alaska Pipeline and marine transportation to the point of delivery. In general, prevailing value is used in lieu of sales price if the sales price is substantially lower than the prevailing value.

Over the years, several different methodologies were used to compute prevailing value. Because there was no established market or spot price for ANS in the earlier years, the Department used a market basket of three foreign crudes delivered to the same market as a production value. In later years, as the market developed, actual sales contracts of ANS were used to establish prevailing value.

As a result of using these methods for computing prevailing value, there is a large backlog of cases waiting for litigation. The oil companies are disputing every step in the process of setting the sales prices, arriving at netback costs, computing the prevailing value, and the Department's right to establish the methodologies. Similar problems exist for the establishment of marine transportation costs. These issues affect royalty collections as well. It has taken several years for the Department to accumulate sufficient knowledge and information about the companies and the markets to establish consistent and fair policies concerning the administration of the law. We believe there is a better way for administration of the tax law that would reduce the conflict between the producing companies and the State of Alaska.

Alaska Tax Value Determination

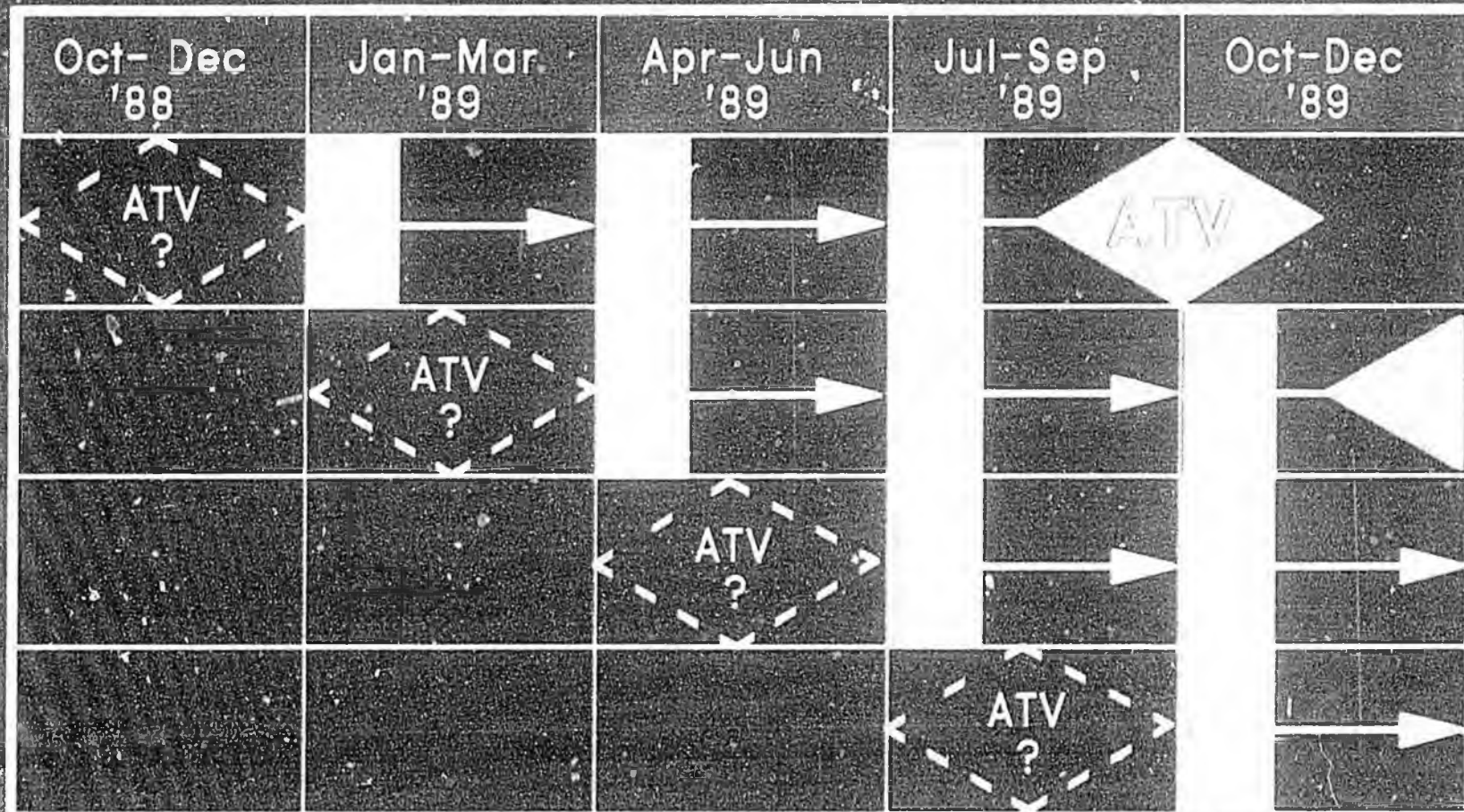
We believe a tax value can be established by a volume weighted average of all arms-length contracts for disposal of ANS. We also believe there is a reasonable method for establishing an average cost of marine transportation to be applied to the sales price.

The following is a description of the procedures we anticipate using to establish a retroactive value for Alaskan crude oil on a quarterly basis:

- 1) Immediately following the end of each calendar quarter, we would visit each producing company and obtain documents and data concerning all transactions conducted the past quarter. We would also obtain current data on marine transportation.
- 2) We would value all arms-length transactions:
 - a) Sales - full cash consideration
 - b) Exchanges - spot price for oil received plus or minus differentials.
- 3) On our return to the producers the following two quarters, we would pick up additional information relating to deliveries such as loadings and unloadings, amendments to contracts, escalations or de-escalations on price, and any other pertinent information.
- 4) At the end of three calendar quarters, we would arrive at the Alaska Tax Value for three months production and announce it to the producers.
- 5) In addition, we would compute the value for royalty oil based on the lease contract and issue it to the producers as well.

ATV Determination Process

Alaska Tax Value



Unknown ATV



Field visit



Announce ATV

Proposed Meeting Agenda

1. What prompted the adoption of your approach for valuing oil?
2. Is the approach used for all tax (and royalty) purposes, or just some?
3. To what production does this norm price or "market value" apply?

- a. all volumes of all crude streams
- b. non-arms-length transactions only
- c. LPGs, condensate, gas, etc.
- d. other subgroups of production

to do others exist in other jurisdictions? what are they?

4. Is the tax reference price calculated on a

- a. company by company basis?
- b. field by field basis?
- c. global (i.e. national) basis?
- d. other?

} participant

5. The reference point for tax value is:

- a. wellhead
- b. field gathering point/processing plant
- UK* -c. point of loading or export
- d. other

6. Is the tax reference price calculated by the taxing authority or by an independent committee/panel? What are the advantages of each approach?

7. Sources of information used in calculating norm price or "market value":

- a. arms-length contracts
- b. published spot prices
- c. netback values
- d. data from other (e.g. local) government bodies

8. If netback values are used, what are the sources of information for transportation cost?

9. If one crude oil value is used as a reference point for valuing other crudes, what method do you use to determine the appropriate differential?

10. How are tax reference prices determined in markets where there are no arms-length sales for the subject crude, or few or no arms-length sales at all?

arms length

11. If actual contracts are used in calculating a tax reference price, should certain contracts be rejected if their terms appear atypical or extreme or otherwise suspicious? Who determines this?

12. Again, if actual contracts are used in calculating a tax reference price, how do you adjust for:

- a. exchanges of crude or products?
- b. differences in credit terms?
- c. differences in flexibility of lifting times?
- d. other, less quantifiable forms of compensation?

13. If actual contracts are used, what level of cooperation (i.e. in making contracts available) do you receive from taxpayers?

14. To what extent are taxpayers encouraged to bring forward (on their own initiative) other information which could be helpful in determining the norm price or "market value"? Do they take advantage of this opportunity?

15. Period covered by a single norm price or "market value":

- a. arguments for monthly tax reference price
- b. arguments for quarterly tax reference price
- c. arguments for some other period

16. Lag between end of period and announcement of tax reference price

- a. how long?
- b. what factors dictate length of lag?
- c. are there ways this might be shortened?
- d. do taxpayers tend to prefer shorter period?

17. Are individual taxpayers allowed to plead for an exception from the tax reference price? Within what time period following announcement? What evidence could be used to justify an exception? What is the appeal procedure? How many appeals have been made, and with what outcomes?

18. Have taxpayers ever reacted to a tax reference price by reducing production or liftings, or by threatening to do so (e.g. when they consider the tax reference price to be unrealistically high)?

19. Do taxpayers ever complain of problems using tax credits in other (e.g. their domicile) jurisdictions because the host country tax is based on a reference price rather than on some other standard? How have such problems (if any) been resolved?

20. What did the oil industry think of your approach when it was first adopted? How do they regard it now?

21. Do independent analysts think your system is accurate?
22. What types of expertise are required to gather the necessary data and to calculate the tax reference price? How do you find or train individuals for these jobs?
23. If Alaska were planning to introduce a tax reference price, do you suggest that taxpayers be invited to contribute comments and ideas to the design of the system? At what stage and in what format?
24. Have you learned, through your experience, of any particular computer hardware or software which could be particularly helpful in assembling data for calculating a tax reference price? Do taxpayers and/or your auditors in the field record value information in a computer format? If so, please describe it for us...
25. Which of your laws and regulations, or their equivalents, should we read prior to our meetings?

This copy for C. LEGSDON



Inland Revenue
Oil Taxation Office

R M Elliss
Controller

Melbourne House
Aldwych
London WC2B 4LL

Telephone 01-438

7719

Mr John C Gault
13 Chemin Alois-Pictet
1234 Vessy
SWITZERLAND

Your reference

My reference

Date

24 September 1987

Dear Mr Gault

Thank you for your letter of 2 September.

Valuations of oil for transactions not at arm's length (defined in paragraph 1 of Schedule 3 Oil Taxation Act 1975 - copy enclosed) were, for periods up to and including 31.12.86, made by reference to paragraphs 2 and 3 of Schedule 3 Oil Taxation Act of which a photocopy is enclosed.

For later periods the way in which market valuations are made has been altered and I enclose a copy of the Press Release of 18 November 1986 and the relevant legislation (Section 62 and Schedule 11 Finance Act 1987).

Yours sincerely

M Williams

MRS M E WILLIAMS

Encs



INLAND REVENUE

Press Release

INLAND REVENUE PRESS OFFICE, SOMERSET HOUSE, STRAND, LONDON WC2R 1LB
PHONE: 01-438 6692 OR 6706

[0x]

18 November 1986

PETROLEUM REVENUE TAX: VALUATION AND PRICING

It was announced in the House of Commons today that the Government would be bringing forward in the 1987 Finance Bill legislation to amend the rules governing the valuation and pricing of oil for Petroleum Revenue Tax (PRT) purposes to take account of current market practices. The amendments to the valuation rule will make clear how monthly valuations are to be determined. A related revision to the pricing rule will apply to the computation of PRT liabilities in respect of certain arm's length sales of Brent Blend crude oil. Representations are invited on the detail of the changes.

In reply to a Parliamentary question, the Financial Secretary to the Treasury, the Right Honourable Norman Lamont MP, today gave the following Written Answer :

The Government recognises that the operation of the current law on PRT valuation is uncertain in the sort of oil market we have today; and that this uncertainty creates problems for the industry. Accordingly, we propose to bring forward legislation in the next Finance Bill to put the valuation of oil for PRT purposes on a more certain and appropriate basis. At the same time we intend to introduce a related measure to determine what will be the basis of PRT liabilities in the case of oil sold at arm's length on the Brent market, where the number of deals done can result in the same cargo of oil being sold many times over. Such a measure is necessary if PRT revenue in these circumstances is not to be eroded. We propose to consult with the industry on the detail of these proposed changes, further details of which are set out in a Press Notice which the Inland Revenue is issuing today. The new legislation will apply from 1 January 1987.

DETAILS OF THE PROPOSED CHANGES

Valuation

1. When oil or gas is disposed of other than by way of a sale at arm's length - for instance, where it is transferred from a producing company to a refining affiliate within the same group - PRT is charged on the "market value" of that oil or gas. "Market value" is determined in accordance with the valuation rules in schedule 3 to the Oil Taxation Act 1975. But those rules were drawn up by reference to the market for North Sea oil as it was in the 1970s, and in some respects

fail to reflect the sort of market conditions which prevail today. Their operation in the context of today's market is thus open to uncertainty. The Government therefore proposes to amend the valuation rules to put them on a more certain basis, and to bring them more clearly into line with the operation of the oil market.

2. Under the proposed amendments to the rules, oil disposed of other than in a sale at arm's length, or appropriated to refining by the producer, will continue to be valued on a monthly basis. As at present, the market value will be determined as the price the oil would have fetched if it had been sold at arm's length under certain specified conditions (governing such matters as place of delivery, credit terms etc). But the Government proposes that the legislation should then go on to make clear that the monthly "market value" will be calculated by reference to an evidential base consisting primarily of prices obtained in arm's length sales of oil of the same kind made by participators and their associates. In the event that there are insufficient sales of a particular crude, account will also be taken of prices obtained in sales of other oil, adjusted as appropriate.

3. The Government further proposes that the legislation should itself specify the time-frame of deals to be taken into account in determining the monthly "market value". It recognises that this is an area where market practice is always liable to change, so what is indicative of monthly market values in today's market conditions may not necessarily remain so for the future. To guard against the new rule itself becoming out of line with future market practice, it proposes that the time-frame of the deals to be taken into account in the determination of monthly market values should be capable of being changed by Order. In the sort of market conditions which prevail today, the Government considers it would be right to take account of all contracts for delivery in the valuation month which have been made in the period starting on the first day of the month preceding delivery and ending on the middle day of the month of delivery. Market value would then be determined each month as an average of prices in deals within the evidential base outlined in this and the preceding paragraph.

Pricing

4. The basic rule in the existing PRT legislation is that where a company has sold the oil it has produced at arm's length, the price achieved in that sale is automatically accepted as the amount on which the company's PRT liability in respect of that oil should be based. This rule works satisfactorily where, for example, a company enters into a single contract covering the sale of a particular quantity of oil, and the producer in due course delivers the oil to the purchaser under the terms of that contract. It is not intended to disturb the operation of the existing legislation in circumstances like these.

Multiple sales on the Brent market

5. But the link between the oil produced, the contract of sale, and eventual delivery is less clear-cut in the sort of forward market which has developed recently in Brent Blend crude oil. A company producing such oil and selling both the oil it has produced and similar oil it has contracted to purchase is able to enter into a multiplicity of paper deals at a range of prices for cargoes for delivery in a

particular month. Often only a proportion of these will result in actual deliveries of oil, and an even smaller proportion in deliveries of oil produced by the company selling. The way in which the Brent forward market operates can thus give Brent producers the opportunity to choose which contract - and hence which price - to assign to those transactions which are liable to PRT (ie sales of their own equity production), and which to assign to their trading transactions.

6. The changes to the PRT pricing rules announced by the Financial Secretary are intended to protect PRT revenue in these circumstances. The changes will apply to specified kinds of oil (only Brent Blend crude oil will be specified in the first instance). In the case of such oil, each month the weighted average of the prices the producer returns for PRT purposes for his arm's length sales will be compared with the "market value" for that month, determined in accordance with the amended valuation rule described in paragraphs 2 and 3 above. In any month where the average of the producer's own returned prices is less than market value for that month, his PRT liability will - unless he has made an election for the alternative basis described in paragraph 7 below - be based, not on the prices returned, but on market value.

7. But a producing company in such circumstances who is able to demonstrate for the chargeable period in question that

(a) none of its associated companies also sold Brent Blend oil; and

(b) the total quantity of Brent Blend contracted to be sold during that period amounted to no more than twice the quantity of that part of its own equity production sold at arm's length

may elect for an alternative basis to apply for that chargeable period. For any month within the chargeable period in which the average of the company's own prices is below market value for that month, PRT will then be based - not on market value - but on the average of the company's own prices in all its sales (both equity and trading) for the month.

8. The measure described in paragraphs 6 and 7 above will not affect the present corporation tax treatment of sales on the Brent market.

Consultation

9. The Government has announced its intention to consult the industry on the detail of the proposed changes to the valuation and pricing rules. Any comments on the proposals set out in this Press Release should be sent to the Board of Inland Revenue, Room S2 West Wing, Somerset House, London WC2R 1LB, to arrive not later than 5 December 1986.

PART V

(5) In subsection (5) of section 2 of the principal Act (amounts to be taken into account in determining whether a gross profit or loss accrues to a participator in any chargeable period) at the end of paragraph (d) there shall be added "and

(e) the excess of the nominated proceeds for that period, as defined in section 61 of the Finance Act 1987."

(6) In relation to any calendar month, the proceeds of a participator's disposals and appropriations from an oil field means the total of—

(a) the price received or receivable for so much of any oil forming part of his equity production from the field in that month as was disposed of by him crude in sales at arm's length; and

(b) the market value, ascertained in accordance with Schedule 3 to the principal Act, of the rest of his equity production from the field in that month;

and in this subsection any reference to a participator's equity production from an oil field in any month shall be construed in accordance with paragraph 1(2) of Schedule 10 to this Act.

(7) The Treasury may by regulations made by statutory instrument make provision for any purpose for which regulations described as "Treasury regulations" may be made under Schedule 10 to this Act.

(8) The Board may by regulations made by statutory instrument make provision, including provision having effect with respect to things done on or after 9th February 1987,—

(a) as to oil which is excluded from this section, as mentioned in subsection (2) above; and

(b) for any purpose for which regulations, other than those described as "Treasury regulations", may be made under Schedule 10 to this Act;

and regulations made by virtue of paragraph (a) above may amend paragraphs (a) and (b) of subsection (2) above.

(9) A statutory instrument made in the exercise of the power conferred by subsection (7) or subsection (8) above shall be subject to annulment in pursuance of a resolution of the Commons House of Parliament.

Market value of oil to be determined on a monthly basis.

62.—(1) In the following provisions of the principal Act (which refer to the market value of oil at the material time in a particular calendar month) the words "at the material time" shall be omitted—

(a) in section 2 (assessable profits and allowable losses), in subsection (9), paragraphs (a)(i) and (a)(ii);

(b) in section 5A (allowance of exploration and appraisal expenditure), subsection (5B);

(c) in section 14 (valuation of oil disposed of or appropriated in certain circumstances), subsections (4) and (4A)(b); and

(d) in paragraph 2 of Schedule 2 (returns by participators), subparagraphs (2)(a)(iii) and (2)(b)(ii).

PART V

(2) In the following provisions of the principal Act (which refer to the market value of stocks of oil at the end of a chargeable period) for the words "at the end" there shall be substituted "in the last calendar month"—

- (a) section 2(4)(b);
- (b) section 2(5)(d); and
- (c) in Schedule 2, paragraph 2(2)(d)(ii);

and in the provisions specified in paragraphs (a) and (b) above for the word "then" there shall be substituted "at the end of that period".

(3) In Schedule 3 to the principal Act (miscellaneous provisions relating to petroleum revenue tax) paragraphs 2, 2A and 3 (market value of oil) shall be amended in accordance with Part I of Schedule 11 to this Act; and the consequential amendments of the principal Act in Part II of that Schedule shall have effect.

(4) A participator in an oil field who is required by paragraph 2 of Schedule 2 to the principal Act to deliver to the Board a return for a chargeable period shall, not later than the end of the second month after the end of that period, deliver to the Board an additional return of all relevant sales of oil (as defined in subsection (6) below) stating—

- (a) the date of the contract of sale;
- (b) the name of the seller;
- (c) the name of the buyer;
- (d) the quantity of oil actually sold and, if it is different, the quantity of oil contracted to be sold;
- (e) the price receivable for that oil;
- (f) the date which, under the contract, was the date or, as the case may be, the latest date for delivery of the oil and the date on which the oil was actually delivered; and
- (g) such other particulars as the Board may prescribe.

(5) Where two or more companies which are participators in the same oil field are members of the same group of companies, within the meaning of section 258 of the Taxes Act, a return made for the purposes of subsection (4) above by one of them and expressed also to be made on behalf of the other or others shall be treated for the purposes of this section as a return made by each of them.

(6) For the purposes of the return required by subsection (4) above from a participator in an oil field, a relevant sale of oil is a contract for the sale of oil to which the participator or any company which is resident in the United Kingdom and associated with the participator for the purposes of section 115(2) of the Finance Act 1984 is a party (as seller, buyer or otherwise), being a sale of oil—

1984 c. 43.

- (a) for delivery at any time during the chargeable period referred to in subsection (4) above; and
- (b) details of which are not included in the return made for the period under paragraph 2 of Schedule 2 to the principal Act (by virtue of sub-paragraph (3A) thereof); and

(c) which is for the delivery of at least 500 metric tonnes of oil; and

(d) which is not a contract for the sale of oil consisting of gas of which the largest component by volume over the chargeable period concerned is methane or ethane or a combination of those gases.

(7) A return under subsection (4) above shall be in such form as the Board may prescribe and shall include a declaration that the return is correct and complete; and if a participator fails to deliver a return under that subsection he shall be liable—

(a) to a penalty not exceeding £500; and

(b) if the failure continues after it has been declared by the court or the Commissioners before whom proceedings for the penalty have been commenced, to a further penalty not exceeding £100 for each day on which the failure so continues;

except that a participator shall not be liable to a penalty under this subsection if the failure is remedied before proceedings for the recovery of the penalty are commenced.

(8) Where a participator fraudulently or negligently delivers an incorrect return under subsection (4) above, he shall be liable to a penalty not exceeding £2,500 or, in the case of fraud, £5,000.

(9) This section has effect with respect to chargeable periods ending after 31st December 1986.

Blends of oil from
two or more fields.

63.—(1) If, at any time prior to its disposal or relevant appropriation, oil won from an oil field is mixed with oil won from another oil field, the provisions of this section shall have effect to determine what is the share of a participator in one of those fields of the oil won from that field in any chargeable period ending after 1st January 1987; and in the following provisions of this section—

(a) “blended oil” means oil which has been so mixed; and

(b) “the originating fields” means the oil fields from which the blended oil is derived.

(2) If, for the purposes of commerce, blended oil is allocated to the participators in the originating fields in accordance with an agreed method, then, subject to the following provisions of this section, for the purposes of the oil taxation legislation, the blended oil which, in accordance with that method, is allocated to a participator in one of the originating fields in respect of any chargeable period shall be taken to be that participator's share of the oil won from that field in that period.

(3) With respect to any blended oil, each of the participators in the originating fields (either jointly or individually) shall, not later than 1st August 1987 or, if it is later, not later than thirty days after the date on which the first allocation is made in accordance with a particular method falling within subsection (2) above, furnish to the Board for the purposes of this section such details as may be prescribed with respect to that method and to the blended oil concerned; and if any participator fails to comply with this subsection he shall be liable—

(a) to a penalty not exceeding £500; and

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SCHEDULE 11

MARKET VALUE OF OIL

PART I

AMENDMENTS OF PARAGRAPHS 2, 2A AND 3 OF SCHEDULE 3
TO PRINCIPAL ACT

1.—(1) Paragraph 2 of Schedule 3 (definition of market value of oil) shall be amended in accordance with this paragraph.

(2) For sub-paragraph (1) there shall be substituted—

“(1) The market value of any oil in any calendar month shall be determined for the purposes of this Part of this Act in accordance with this paragraph.”

(3) In sub-paragraph (2) for the words from the beginning to “to be delivered” in paragraph (b) there shall be substituted—

“(2) Subject to the following provisions of this paragraph, the market value of any oil in a calendar month (in this paragraph referred to as “the relevant month”) is the price at which oil of that kind might reasonably have been expected to be sold under a contract of sale satisfying the following conditions—

- (a) the contract is for the sale of the oil at arm's length to a willing buyer;
- (b) the contract is for the delivery of the oil at a time in the relevant month;
- (c) the contract is entered into within the period beginning at the beginning of the month preceding the relevant month and ending on the middle day of the relevant month or, if the Treasury by order so direct, within such other period as may be specified in the order;
- (d) the contract requires the oil to have been subjected to appropriate initial treatment before delivery;
- (e) the contract requires the oil to be delivered”.

(4) In sub-paragraph (2), paragraph (c) shall become paragraph (f) and shall be amended as follows—

- (a) for the words “as at a particular time” there shall be substituted “as in a particular month”; and
- (b) for the words “as at that time” there shall be substituted “as in that month”.

(5) At the end of sub-paragraph (2) there shall be added the words “and, for the purposes of paragraph (c) above, the middle day of a month containing an even number of days shall be taken to be the last day of the first half of the month, and the power to make an order under that paragraph shall be exercisable by statutory instrument which shall be subject to annulment in pursuance of a resolution of the Commons House of Parliament.”

(6) After sub-paragraph (2) there shall be inserted the following sub-paragraphs—

“(2A) For the purpose of sub-paragraph (2) above, the price of any oil in a calendar month shall be determined, subject to sub-paragraphs (2B) and (2C) below, by taking the average of the prices under actual contracts for the sale of oil of that kind—

- (a) which are contracts for the sale of oil by a participator in an oil field or by a company which, for the purposes of section 115(2) of the Finance Act 1984, is associated with such a participator; and
- (b) which, subject to sub-paragraph (2B) below, satisfy the conditions in paragraphs (a) to (e) of sub-paragraph (2) above; and
- (c) which do not contain terms as to payment which differ from those customarily contained in contracts for the sale at arm's length of oil of the kind in question.

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1984 c. 43.

(2B) For the purposes of sub-paragraph (2A)(b) above, a contract shall be treated as fulfilling the condition in paragraph (c) of sub-paragraph (2) above if it contains provisions under which the price for oil to be delivered in the relevant month either is determined or subject to review in the period relevant for the purposes of that paragraph or is determined by reference to other prices which are themselves determined in that period, being prices for oil to be delivered in the relevant month.

(2C) The average referred to in sub-paragraph (2A) above shall be determined—

- (a) by establishing an average price for oil of the kind in question for each business day within the period relevant for the purposes of sub-paragraph (2)(c) above; and
- (b) by taking the arithmetic mean of the average prices so established; and in this sub-paragraph "business day" has the same meaning as in the Bills of Exchange Act 1882.

1882 c. 61.

(2D) If or in so far as the Board are satisfied that it is impracticable or inappropriate to determine for the purposes of sub-paragraph (2) above the price of any oil in a calendar month as mentioned in sub-paragraph (2A) above (whether by virtue of an insufficiency of contracts satisfying the conditions or of information relating to such contracts or by virtue of the nature of the market for oil of the kind in question or for any other reason), that price shall be determined,—

- (a) so far as it is practicable and appropriate to do so by reference to such other contracts (whether or not relating to oil of the same kind) and in accordance with the principles in sub-paragraph (2C) above; and
- (b) so far as it is not practicable or appropriate to determine it as mentioned in paragraph (a) above, in such other manner as appears to the Board to be appropriate in the circumstances."

(7) In sub-paragraph (3)—

- (a) for the words "as at a particular time" there shall be substituted "as in a particular month";
- (b) the words "at that time", where they first occur, shall be omitted;
- (c) after the words "was disposed of" there shall be inserted "in that month";
- (d) for the words "and (2)" there shall be substituted "to (2D)";
- (e) for the words "as at that time" there shall be substituted "as in that month"; and
- (f) for "(2)(b)" there shall be substituted "(2)(c)".

2. In paragraph 2A of that Schedule (modifications in the case of oil consisting of gas)—

- (a) in sub-paragraphs (1) and (3) for "(1) and (2)" there shall be substituted "(1) to (2D)";

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(b) in sub-paragraph (2) for "(2)(a)" in each place where it occurs, there shall be substituted "(2)(d)"; and

(c) in sub-paragraph (3) for "(2)(b)" there shall be substituted "(2)(e)".

3. In paragraph 3 of that Schedule (aggregate market value of oil for purposes of section 2(5))—

(a) in sub-paragraph (1) the words "at the material time" shall be omitted; and

(b) in sub-paragraph (2) the words from "and 'the material time'" onwards shall be omitted.

PART II

CONSEQUENTIAL AMENDMENTS OF PRINCIPAL ACT

4. In section 5A (allowance of exploration and appraisal expenditure) in subsection (5C)(a) for "(c)" there shall be substituted "(f)".

5. In section 12 (interpretation) in subsection (1) in the definition beginning "calendar month" for the words from "and" to "have" there shall be substituted "has".

6. In section 14 (valuation of oil disposed of or appropriated in certain circumstances)—

(a) in subsections (1) and (2) for the words "at a particular time" there shall be substituted "in a particular month";

(b) in subsection (5) for the words from the beginning to "this Act", in the first place where those words occur, there shall be substituted "In subsections (4) and (4A) above "calendar month" means a month of the calendar year"; and

(c) in paragraph (a) of subsection (5) for "(2)(c)" there shall be substituted "(2)(f)" and for "(c)" there shall be substituted "(f)".

7. In Schedule 9 (sales etc. at undervalue or overvalue) in paragraph 6 (determination of arm's length price) for sub-paragraph (2) there shall be substituted—

"(2) In this paragraph "calendar month" means a month of the calendar year and "material time", in relation to a calendar month, means noon on the middle day of the month which, in the case of a month containing an even number of days, shall be taken to be the last day of the first half of the month."

Section 63.

SCHEDULE 12

SUPPLEMENTARY PROVISIONS AS TO BLENDED OIL

Interpretation

1. In this Schedule—

(a) "the principal section" means section 63 of this Act;

(b) "blended oil" and "the originating fields" have the same meaning as in the principal section;

(c) a "method of allocation" means such a method as is referred to in subsection (2) of the principal section; and

(d) "the oil taxation legislation" means Part I of the principal Act and any enactment construed as one with that Part.

1 INTRODUCTION

Within UK designated areas, mainly in the North Sea, lie some of the largest oil and gas fields found on the continental shelf. The United Kingdom also has a number of onshore fields but they are all relatively small.

Ownership of oil or gas in place, whether onshore or offshore, rests with the State and the Government has the power to award licences which permit exploration or development in the areas covered.

For offshore areas there are two kinds of licence:

- (1) The exploration licence – is a non-exclusive licence and entitles the holder to conduct preliminary exploration activities in any area apart from one covered by a production licence.
- (2) The production licence – entitles the holder to explore, appraise and develop, subject to consent from the Department of Energy (DoE) any field in the specified area.

Production licences are awarded for defined areas which have been offered, either under cash tender or for a fixed price, under successive licensing rounds. To date there have been ten separate licensing rounds.

The onshore licensing system is broadly similar but exploration licences are awarded for specific areas and are now awarded under the licensing round procedure.

2 FISCAL REGIME – CORPORATE

The Government 'take' from oil and gas revenues comprises the following elements:

- (1) Government royalties
- (2) Petroleum revenue tax
- (3) Corporation tax

A special office, the Oil Taxation Office (OTO), deals with the tax affairs of oil companies and royalties are dealt with by the DoE.

(1) Government Royalties

Offshore fields, other than those in the Southern Basin of the North Sea, for which the DoE made the decision to allow development on or after 1 April 1982 are exempt from Government royalty.

For non exempt offshore fields the precise royalty calculation is determined by the round in which the licence was issued. For fifth and later round licences royalty is 12.5% of the landed value of production. For fourth and earlier round licences deductions are allowed for conveying and treating costs, thus making the well head the point of valuation.

The Government takes some of its royalty entitlement in kind and in these cases if a fourth or earlier round licence is involved it pays amounts to the oil company to cover the conveying and treating costs of the oil taken in kind.

For onshore licences issued since 1982 the royalty rate is normally flat 12.5% but under earlier licences royalty is charged on a graduated basis with 12.5% as the highest rate.

(2) Petroleum Revenue Tax (PRT)

PRT, now charged at 75%, is assessed on profits from oil won under the authority of a licence on a 'field by field' basis, ie the taxable unit is the particular oil or gas field whose co-ordinates are determined by the DoE on geological characteristics. In general losses relating to one field cannot be set against profits of other fields. Although PRT applies to both onshore and offshore fields, onshore fields are generally unlikely to pay PRT because of their size and production rates.

PRT is assessed, for 6 monthly chargeable periods, at 75% on net profit less "oil allowance" subject to a possible reduction under an alternative calculation ("safeguard").

The net profit for PRT purposes is the sum of the positive amounts less the sum of the negative amounts.

The major items included as positive amounts are:

- Proceeds from arm's length sales of oil (Note a)
- Market value of non-arm's length disposals of oil (Note a)
- Market value of oil appropriated to refining
- The excess of market value over nominated proceeds (Note b)
- One half the market value of oil in 'stock' at the end of the period (reversed in the next period)
- Tariff receipts net of any tariff receipts allowance (Note c)
- Disposal receipts
- Conveying and treating receipts.

The major items included as negative amounts are:

Royalty payable (including annual licence rentals)
 Field expenditure (Note d)
 "Uplift" (Note e)
 Exploration and appraisal expenditure
 Research and development expenditure
 Cross-field expenditure allowed by the OTO
 Abortive exploration expenditure
 Unrelieved field losses
 Any net loss from the preceding period.

The following points are relevant:

- (a) Oil sales are at arm's length only if certain conditions are met. It is not sufficient for sales merely to be to an unconnected party.

If the arm's length conditions are not met market value is substituted for sales proceeds, market value now being determined by reference to an evidential base of comparable arm's length sales.

- (b) To prevent the oil companies manipulating which oil sales are subject to PRT a nominations system has been introduced. If arm's length sales are not correctly nominated an adjustment is now made to replace sales proceeds with market value.
- (c) Tariff receipts – field assets, such as pipelines and terminals, may be used by other, usually newer fields. This generates tariff receipts, usually calculated on the basis of throughput of oil, which are subject to PRT in the hands of the recipient. A quantity allowance is granted as a deduction for each period, the tariff receipts allowance.
- (d) Allowable expenditure – expenditure deducted against an assessment is generally that agreed and determined by the OTO since the previous assessment, rather than that expenditure incurred in the period.

Field expenditure must fall under certain prescribed headings, which cover exploration costs through to selling costs but PRT does not extend to "downstream" operations.

Certain expenditure is specifically disallowed, in particular interest, the cost of acquiring land and with certain exceptions the cost of a building or structure on land.

Long-term assets, ie assets having a useful life extending beyond the period covered by the expenditure claim, are subject to certain special rules. Full front-end relief is granted for most long term assets, the exception being long-term assets which are mobile and not dedicated to any particular field. Relief for expenditure on such assets is spread over the life of the asset and allocated to the various fields on which the asset is successively used.

- (e) Uplift – a special allowance intended to compensate for the lack of an interest deduction. Uplift is currently granted at 35 per cent of qualifying expenditure, broadly initial appraisal and development expenditure.

Uplift is not available on expenditure incurred after the field has reached a break-even point. There are detailed rules to calculate when "payback" occurs.

- (f) The fourth to eighth items of the negative amounts above are the areas where the field concept has been breached. They are fairly restricted but have been gradually expanded to encourage exploration and development.

- (g) Oil allowance – is the cash equivalent of a quantity of oil. It is used only if a net profit exists for a particular period and is granted until overall maximum quantity has been used.

For offshore fields, other than Southern Basin fields, for which development consent was given on or after 1 April 1982, the oil allowance is 500,000 metric tonnes for each chargeable period with a maximum aggregate quantity of 10 million metric tonnes. For on-land fields these quantities are halved.

- (h) Safeguard – is an alternative calculation of PRT, intended to guarantee a minimum return from the field. It is only available for a fixed number of chargeable periods in the early years of a field's life. The number of periods for which safeguard is available is 1½ times the number of chargeable periods in the "payback period".

Administration

PRT is payable for 6 monthly chargeable periods ending June and December. Returns of income and an estimated PRT calculation are due two months after the end of the period and the tax calculated payable, net of any previous stage payments, is then due.

An assessment is due within five months of the end of the period and any balance of tax is due by the end of the sixth month. It should be noted however that interest runs from the end of the second month in any event (also on any repayment due).

Additionally 6 stage payments are required, each one equal to one-eighth of the calculated (not assessed) liability for the previous period. These are due monthly commencing at the end of the second month in the period.

Corporation Tax

Companies engaged in oil or gas exploitation are subject like other companies to UK corporation tax on their trading profits but the following special rules apply:

The ring fence - UK oil and gas extraction activities are treated as a separate trade from other trading activities carried on by the company. The profits from this separate trade - 'the ring fence trade' - may not be reduced by losses from other activities. On the other hand losses from the ring fence trade may be used to reduce profits from non-ring fence activities.

Where a company has both ring fence and non-ring fence activities loan interest can only be deducted from ring fence profits to the extent that the loan was used to meet expenditure relating to the ring fence trade. Interest allowed on loans from an associated company is restricted to a reasonable commercial rate, and the OTO are contending that "thin capitalisation" rules apply.

There are also restrictions, in some circumstances, on the use of advance corporation tax by an exploration and production company.

Sales values - if market value is used for PRT purposes those same values are normally substituted for actual sales proceeds in the corporation tax computation.

Capital allowances - items of plant and machinery such as drilling rigs, production platforms, pipe-lines etc, qualify for a 25 per cent writing down allowance each year calculated on the reducing balance basis.

Exploration and appraisal expenditure qualifies for scientific research allowances which give immediate relief for 100% of the cost to a company which is carrying on a 'related trade'. If the company does not have such a trade the relief will only become available if such a trade is set up and commenced. It is accepted by the OTO that a development decision constitutes commencement to trade.

Intangible development drilling costs (with the possible exception of the first development well) can be deducted as revenue expenditure under what is known as the New Brunswick rule. The OTO now argues that expenditure on the first development well of a particular field only qualifies for mineral extraction allowances. These are writing down allowances which are available at two levels, 10% pa for acquisition of a mineral asset and 25% pa for winning access and certain other qualifying expenditure.

(d) Royalty and PRT are deducted in computing taxable profits.

Administration

Corporation tax is normally payable 9 months after the end of the company's accounting period.

3 FISCAL REGIME - INDIVIDUAL

Employees whose duties are performed offshore in the UK sector of the continental shelf are treated under a special provision as working in the United Kingdom. This means that the more favourable treatment of earnings for duties performed outside the United Kingdom which applies in certain circumstances is not available.

4 FISCAL REGIME - OTHER

The UK sector of the continental shelf (outside the 12 mile limit) is not part of the United Kingdom for VAT purposes. It is therefore possible to 'export' various services relating to the offshore installations and so obtain the benefit of 'zero-rating'. The treatment of the supplies normally made in connection with offshore oil and gas activities has been agreed on an industry basis with the Customs and Excise authorities.

PRODUCTION

The Norwegian sector of the North Sea has several large oil and gas fields currently producing. Because of the potential impact on the economy of such a small nation Norway has pursued a policy of structured development of its oil and gas resources. Each development requires approval of the Storting (parliament), and the State participates in each licence through Statoil (the 100% State owned oil company), whose costs up to 1 January 1987 were carried by the other participant in each venture prior to a find being declared commercial. The State and Statoil are not carried in licences issued after 1 January 1987. Statoil's interest in existing licences is between 30% and 85% and if Statoil is not initially the operator on a licence there are usually provisions enabling Statoil to assume that role at a later date.

REGIME - CORPORATE

Norway has four main levies on oil and gas production.

Production fee (Royalty)

Income Tax

Special Petroleum Tax

Capital Tax

Production fee (Royalty)

Production fee is charged on each licensee under a licence. It is only charged on fields whose development plan was accepted before 1 January 1987.

The rate is a flat 10% on licences issued before 1972 and varies with production for later licences.

The licensee is required to pay a production fee of 8% of the value of the quantity of oil produced. From the time when the quantity of oil produced from one production area reaches the following average quantities over a 30-day period, the production fee is paid at the following rates on the value of the whole quantity:

6,500 Standard cubic metres per day	975 b/d	10%
16,000 Standard cubic metres per day	2400 b/d	12%
35,000 Standard cubic metres per day	5250 b/d	14%
55,000 Standard cubic metres per day	8250 b/d	16%

If the daily average for the first 30 days of production from a production area exceeds the level at which the fee is 8%, the production fee is raised from the day when the production first exceeded the level in question.

If the daily average of production from a production area for which a production fee of more than 12% has been paid should later fall under the relevant limit during a 30-day period, the production fee is reduced correspondingly in accordance with the table from and including this period, but not to less than 12%.

On produced petroleum other than oil, a production fee of 12½% is payable.

Costs of construction and operation of pipelines from the individual production installation to the production area shipment point are deductible when calculating the production fee, if the Ministry regards it as reasonable in view of the distance of transportation and other prevailing circumstances.

When granting an individual production licence or subsequently, the Ministry may stipulate lower production fee rates if the depth of the sea, the capacity per well or other circumstances so indicate.

Valuation of oil is under the "norm price" system in operation in Norway. This price is established for oil for each field in respect of each calendar quarter. It is "equivalent to the price at which petroleum could have been sold between independent parties in a free market". The price is fixed by a board appointed by the Ministry of Energy. However, the production fee for oil is usually paid in kind.

Although the norm price system allows a gas price to be established this has never been done.

(2) Income Tax

Income tax is governed by the General Tax Act of 1911, and is generally split between a municipal tax of 23% and a state tax of 27.8%. These taxes are both paid to the state where offshore operations are concerned.

The major difference is that dividends paid in accordance with the Companies Act 1976 are deductible in computing profits for the state tax but not the municipal tax. The 1976 Companies Act restricts dividends by reference to reserve fund rules.

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All expenses incurred in order to obtain or secure income are tax deductible.

The normal income tax rules are amended in several ways by the Petroleum Tax Act for offshore operations:

income from oil is computed under the "norm price" rules

there are several adjustments to book income, some of them only affecting the timing of a deduction.

- (i) Exploration costs may either be expensed currently or deferred and amortised.

Exploration costs include all expenditure incurred prior to an area being declared commercial.

If the costs are capitalised the amortisation period is at the discretion of the taxpayer but amortisation must end within 5 years from the related field coming on stream.

Interest on loans used to finance exploration costs may similarly be expensed immediately or capitalised. The deduction of interest on company loans is however subject to thin capitalisation rules.

- (ii) Exploration expenditure must be capitalised and depreciated. The expenditure to be capitalised includes wages of employees in development work and overhead costs.

Offshore production assets are depreciated on a straight line basis over a minimum period of 6 years. The depreciation must be provided in the company's accounts to be allowable for tax purposes.

Depreciation commences when the asset comes into use, but from the year of investment for assets acquired after 1 January 1987.

The normal rules of the General Tax Act apply to onshore assets which are depreciated on a declining basis at rates from 2% to 30%.

For assets acquired before 1 January 1987 depreciation is not available until the particular field under development begins production and accordingly development costs of such a field cannot be offset against taxable income from a currently producing field until the field commences production.

(iii) production costs are expensed as incurred.

- (c) There is no restriction on utilisation of losses from operations on the continental shelf against profits from other activities. However, because the special petroleum tax is assessed on the same basis as income tax, it is usually preferable to carry offshore losses forward. There is a maximum 15 year loss carry forward but the Ministry of Finance has power to extend the period.

Losses may be carried backwards for two years if an activity ceases.

Only 50% of losses from activities not carried out on the continental shelf may be set off against profits from continental shelf activities.

(3) Special Petroleum Tax

Introduced by Section 5 of the 1975 Petroleum Tax Act

Charged at the rate of 30% (25% prior to 1980) on those who produce or transport petroleum through pipelines.

The special tax is assessed on the same basis as income tax with the following exceptions:

- (a) no dividend deduction
- (b) losses from other activities are not deductible
- (c) a special deduction is allowed.

For fields whose development plan was accepted before 1 January 1987 this deduction consists of an uplift comprising an annual deduction of 6 2/3% of the uplift base. An asset remains in the uplift base for 15 years, giving total uplift of 100%. An individual asset enters the base in the year following its first depreciation. If a field does not produce for the 15 years required to obtain 100% uplift the uplift rate may be adjusted.

Pipeline uplift may, if the pipeline is owned by a separate company and the uplift exceeds the assessable profit, be allocated amongst the pipeline users to the extent of the excess.

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Prior to 1980 uplift was 10% pa over 15 years.

For fields whose development plan was accepted after 1 January 1987 no uplift can be claimed. Special tax is calculated on the net income that exceeds a "production grant". For 1987 the production grant is set at 15% of the value of produced petroleum (for oil based on norm prices).

Grant and Payment Procedures

Income tax and the special petroleum tax are assessed by a special Assessment Board.

A return of income for the preceding calendar year is submitted to the Oil Taxation Office by 1 April. The Oil Taxation Office makes a recommendation to the Assessment Board. The recommendation is presented to the company for comments. After consideration of the company's comments and any further information requested, the Assessment Board raises an assessment in the autumn of the assessment year.

Any appeal must be lodged within 3 weeks, although in practice a preliminary appeal stating the items subject to appeal is accepted. A full appeal is subsequently prepared.

Any court proceedings must be commenced within 6 months of the determination of the appeal.

Payment of the income tax and special petroleum tax is in two instalments, based on a preliminary estimate of income provided to the Oil Taxation Office in August of the year in question. The instalments are payable in October and the following April and are based on a preliminary assessment.

Any balance of tax due or refund is paid after the issue of the final assessment. Interest is payable or receivable as the case may be.

Abandonment

Norway has decided not to allow tax deductions for abandonment provisions or actual costs but has proposed a system of Government grants, which will not be taxable. The grant will be negotiated on a field by field basis. It is intended that the grant will approximate the level of tax relief that would have been obtained if a deduction for abandonment costs was allowed.

Thin Capitalisation

Interest costs are deductible for both income tax and special petroleum tax but the Oil Taxation Board has laid down rules on both debt/equity ratios and interest rates. The main rule on debt/equity ratios is:

- (a) Exploration phase - 100% equity required
- (b) Development phase - 20% equity required
- (c) Production phase - 100% debt allowed.

Further the interest rate must not exceed market rate.

The above restrictions will apply if debt is obtained from an affiliated company or is guaranteed by an affiliated company. The debt/equity restrictions will generally not apply if the borrower (licensee) has other licences that are on-stream, thus generating income sufficient to pay a higher percentage of loan financing.

Research and Development

As a condition of obtaining new licences oil companies have often made payments to Norwegian companies for research and development projects. The tax treatment of these payments has varied. In 1984 it was accepted that such contributions could be expensed immediately for both income tax and special tax purposes. The Government has since decided that the contributions cannot be deducted against offshore income for special tax purposes.

Ekofisk Waterflood Project

In 1983 a special law was passed to improve the economics of this particular and other waterflood projects. The Government accepted that the project was not viable without special incentives and it is expected that this may be a forerunner of future incentives granted on a case by case basis.

(4) Capital Taxes

Capital taxes are paid by Norwegian corporations at 0.3% (1987) of net worth.

Net worth is arrived at by deducting all debt (excluding income tax) from assets. Assets are normally valued at book value. Capitalized exploration costs are excluded. Depreciable assets used in petroleum production or pipeline transportation are valued at book value excluding capitalized interest and exchange losses. Other plant and machinery is usually accepted at book value except onshore real property for which separate tax values exist.

Oil stocks are valued either at book value (cost of production) or at norm price if they have been transported beyond the norm price point.

3 FISCAL REGIME - INDIVIDUALS

An individual resident or domiciled in Norway is taxed on worldwide income. Non residents are taxed on income from Norwegian sources. This includes earnings from employment in the Norwegian sector of the North Sea.

There are both state and municipal taxes. State taxes are levied at rates up to 34% on net income exceeding NoK 215,000 (NoK 258,000 for individuals with dependents).

Municipal taxes are levied at 22% and not deductible for state tax purposes. Most benefits in kind are taxed.

Social security premiums are charged at 11.4% of gross income from individuals, plus 17.1% from employers.

The tax year follows the calendar year and returns must be submitted by 31 January of the following year.

4 FISCAL REGIME - OTHER

Value added tax is charged on most goods and services supplied in Norway at 20%. For continental shelf activities the VAT is zero rated.

Customs and Excise duties are payable.

- (a) two months after the end of the chargeable period for which the assessment was made; or
 - (b) the date on which it was paid,
- whichever is the later, until repayment(a))(b).

SCHEDULE 3

Section 1.

PETROLEUM REVENUE TAX: MISCELLANEOUS PROVISIONS

Definition of sale of oil at arm's length

1.—(1) For the purposes of this Part of this Act a sale of any oil is a sale at arm's length if, but only if, the following conditions are satisfied with respect to the contract of sale, that is to say—

- (a) the contract price is the sole consideration for the sale;
- (b) the terms of the sale are not affected by any commercial relationship (other than that created by the contract itself) between the seller or any person connected with the seller and the buyer or any person connected with the buyer; and
- (c) neither the seller nor any person connected with him has, directly or indirectly, any interest in the subsequent resale or disposal of the oil or any product derived therefrom.

(2) Section 533 of the Taxes Act (connected persons) shall apply for the purposes of the preceding sub-paragraph.

Definition of market value of oil

2.—(1) For the purposes of this Part of this Act the market value of any oil shall be ascertained in accordance with this paragraph; and in this paragraph the time as at which market value is to be ascertained is referred to as "the relevant time"(c).

(2) Subject to the following provisions of this paragraph, the market value of any oil at the relevant time is the price at which the oil could have been sold to a willing buyer at that time in a sale at arm's length under a contract of sale made at that time and satisfying the following conditions, that is to say—

- (a) the contract requires the oil to have been subjected to appropriate initial treatment before delivery;
- (b) the contract requires the oil to be delivered—/

(a) 1980(P) s. 2 in relation to tax charged for any period ending on or after 31 December 1979. Originally "from four months after the end of the chargeable period for which the assessment was made until repayment".

(b) See 1982 s. 139(6) and Sch. 19 para. 13(5) in respect of repayments due in respect of the chargeable period ending on 30 June 1983.

(c) See—

1982 s. 134 and Sch. 18—*alternative valuation of ethane used for petrochemical purposes.*

1986 s. 109—*alternative valuation of light gases where an election is made under 1986 s. 109 and accepted by the Board.*

(i) in the case of oil extracted in the United Kingdom, at the place of extraction; or

(ii) in the case of oil extracted from strata in the sea bed and subsoil of the territorial sea of the United Kingdom or of a designated area, at the place in the United Kingdom at which the seller could reasonably be expected to sell it or, if there is more than one such place, the one nearest to the place of extraction;

(c) in the case of oil whose market value falls to be ascertained as at a particular time for the purposes of paragraph (b) of section 2(4) or paragraph (d) of section 2(5) of this Act or, subject to sub-paragraph (3) below, under paragraph 3 below for the purposes of paragraph (b) or (c) of the said section 2(5), the contract is for the sale of the whole quantity of oil whose market value falls to be ascertained as at that time for the purposes of the paragraph in question, and of no other oil [and, for the avoidance of doubt, it is hereby declared that the terms as to payment which are to be implied in the contract shall be those which are customarily contained in contracts for the sale at arm's length of oil of the kind in question(a)].

(3) If oil whose market value falls to be ascertained as at a particular time under paragraph 3 below for the purposes of paragraph (b) of the said section 2(5) was not all disposed of to the same person, then the market value at that time of so much of that oil as was disposed of to any one person shall be ascertained in accordance with sub-paragraphs (1) and (2) above as if that were the only oil whose market value fell to be ascertained as at that time for those purposes (with sub-paragraph (2)(b) above applying accordingly).

[(3A) Where all or any of the oil whose market value falls to be ascertained in accordance with sub-paragraphs (1) and (2) above has been subjected to initial treatment before being disposed of or relevantly appropriated, the appropriate initial treatment referred to in sub-paragraph (2)(a) above shall, as respects that oil, include the whole of that treatment(b).]

(4) The provisions of sub-paragraphs (2) and (3) above shall apply for the ascertainment of the market value of oil in any case mentioned in paragraph 2(2) of Schedule 2 to this Act as they apply in relation to the corresponding case mentioned in those provisions.

[2A.—(1) Paragraph 2 above shall have effect in accordance with this paragraph where the oil whose market value falls to be ascertained at

(a) 1983 s. 38.

(b) 1980 s. 109(6) in relation to chargeable periods ending after 31 December 1979.

any time in accordance with sub-paragraphs (1) and (2) of that paragraph, or in accordance with those sub-paragraphs as modified by sub-paragraph (3) of that paragraph, consists of or includes gas(a).

(2) Sub-paragraph (2)(a) of paragraph 2 above shall not apply to so much of the oil as consists of gas unless—

- (a) it has been subjected to initial treatment before being disposed of or relevantly appropriated; or
- (b) it has, after being disposed of or relevantly appropriated, been subjected to initial treatment by or on behalf of the participator in question or by or on behalf of a person who is connected with him within the meaning of section 533 of the Taxes Act;

and where oil consisting of gas has, whether before or after being disposed of or relevantly appropriated, been subjected to initial treatment by or on behalf of the participator in question or by or on behalf of a person who is connected with him as aforesaid the appropriate initial treatment referred to in sub-paragraph (2)(a) of paragraph 2 above shall include the treatment to which it has been so subjected.

(3) Where the initial treatment mentioned in sub-paragraph (2) above includes treatment in order to separate gas of one or more kinds which are transported and sold in normal commercial practice, the market value of the gas of each such kind which is separated shall be ascertained in accordance with sub-paragraphs (1) and (2) of paragraph 2 as if that were the only oil whose market value fell to be ascertained at the time in question (with sub-paragraphs (2)(b) of paragraph 2 applying accordingly).

(4) Where the oil consists of or includes natural gas within the meaning of the Energy Act 1976, it shall be assumed for the purposes of paragraph 2—

1976 c.76.

- (a) that any authorisation granted under section 7 or 8 of the Gas Act 1986 for the supply of the gas under the contract mentioned in sub-paragraph (2) of that paragraph; and
- (b) that no authorisation is required under those sections for the supply of the gas under that contract if no such

1986 c.44.

(a) See—

1982 s. 134 and Sch. 18—*alternative valuation of ethane used for petrochemical purposes.*

1986 s. 109—*alternative valuation of light gases where an election is made under 1986 s. 109 and accepted by the Board.*

authorisation is required for the supply of the gas (a)(b).]

Aggregate market value of oil for purposes of section 2(5)

3.—(1) For the purposes of subsection (5) of section 2 of this Act the aggregate market value of any oil falling within paragraph (b) or (c) of that subsection shall be arrived at by ascertaining, for each calendar month in the chargeable period in question, the market value at the material time of so much, if any, of that oil as was—

(a) in the case of oil falling within the said paragraph (b), delivered as there mentioned in that month;

(b) in the case of oil falling within the said paragraph (c), appropriated as there mentioned in that month.

and, in either case, aggregating the market values so ascertained(c).

(2) In this paragraph and elsewhere in this Part of this Act "calendar month" (where those words are used) means a month of the calendar year, and "the material time", in relation to a calendar month, means noon on the relevant day, that is to say—

(a) for a month containing an odd number of days, the middle day of the month;

(b) for a month containing an even number of days, the last day of the first half of the month.

Oil delivered in place of royalties to be disregarded for certain purposes

1934 c.36.

4. Oil delivered to the Secretary of State under the terms of a licence granted under the Petroleum (Production) Act 1934 shall be disregarded for the purposes of section 2(5) of this Act and for the purposes of the references in section 8(3) and (4) of this Act to a participator's share of the oil won and saved from an oil field in a chargeable period.

(a) Gas Act 1986 (c.44) s. 67(1) and Sch. 7 para. 20 from a date to be appointed by the Secretary of State. Previously "(a) that any consent given under [section 29 of the Gas Act 1972(ax)] for the supply or use(bx) of the gas applies to the supply of the gas under the contract mentioned in sub-paragraph (2) of that paragraph and to the use of the gas supplied under it(bx); and (b) that no consent is required under [that section(ax)] for that supply or use(bx) if no such consent would be required if that contract were in fact made by the participator in question."

(b) 1980 s. 109(7) in relation to chargeable periods ending after 31 December 1979.

(c) See—

1982 s. 134 and Sch. 18—*alternative valuation of ethane used for petrochemical purposes.*

1986 s. 109—*alternative valuation of light gases where an election is made under 1986 s. 109 and accepted by the Board.*

(ax) Oil and Gas (Enterprise) Act 1982 (c. 23) s. 37 and Sch. 3 para. 22 and S.I. 1982 No. 1059 (C. 33) with effect on 18 August 1982. Previously "section 8 or 9 of that Act" and "those sections".

(bx) Repealed by the Oil and Gas (Enterprise) Act 1982 (c. 23) s. 37 and Schs. 3 para. 22 and 4 and S.I. 1982 No. 1059 (C. 33) with effect on 18 August 1982.

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

ATTN: James Rhode
Special Assistant to the Commissioner

FROM: Roger Marks
Petroleum Economist

DATE: February 23, 1988

SUBJECT: North Sea Taxation Structure

Pursuant to your request, we have compiled a synopsis of the petroleum taxation structure for Great Britain and Norway. As these structures have been subject to frequent modification, for simplicity we have only described the current structure, given the best information available to us.

Great Britain

Petroleum rights accrue to the government through the Petroleum Production Act of 1934. The Continental Shelf Act of 1964 grants jurisdiction over the continental shelf. Licenses to explore and produce are granted through periodic licensing rounds. Awards are made by discretion, with technical and financial attributes, as well as contributions to the economy as criteria.

The Oil Taxation Act of 1975 provides the basis of taxation. There are three main taxes: royalties, the Petroleum Revenue Tax (PRT), and corporate income taxes.

Royalties are at a one-eighth rate, but applied to different bases. In the first licensing rounds they applied to gross revenue at the wellhead, which is the landed value less transportation and initial treatment expenses. In later licensing rounds they were based on the landed price. Properties leased since 1982 have had no royalties.

The PRT is a tax on profits, and is levied field by field in the North Sea. Currently the tax has a 75% rate applied to a base of gross revenues minus allowances. The allowances include accrued field losses, operating costs, royalties, exploration costs, and an "uplift" allowance of 35% (or 135% of capital costs). The uplift is restricted to expenditures incurred up to the time of payout, including the uplift. An accumulated five million tons is exempt from the tax, with a maximum of 0.5 million tons in any one year. Since 1983 new fields get an accumulated 10 million ton exemption with a maximum of 1 million tons a year.

If gross profits for a field are less than 15% of the accumulated field investment the PRT is zero. There is a maximum PRT of 80% of the excess of gross profits over 15% of the field investment.

Since 1987 the producer has had the option to utilize a crossfield allowance, where 10% of the development costs prior to payback can be applied against the PRT income from other fields. No uplift is available on the expenditure to which the allowance relates.

Research and development costs not related to specific fields can be deducted from PRT income after three years.

Petroleum is subject to normal corporate income taxes. In 1974 a "one way ring fence" was established around the North Sea, where losses and capital allowances outside could not be set against income within, but losses within could be set against outside income.

The corporate tax rate is currently 35%. Exploration and development drilling costs can be expensed. Other deductions include losses, operating costs, interest, royalties, the PRT, and depreciation, figured on a 25% declining balance basis.

Norway

Norway's structure is similar to Britain's. Mineral rights are vested in the Crown and licensing is done by discretion. There are three main taxes: the royalty, corporate income taxes, and a Special Tax *and capital tax*

Royalties are part of the license. The base is gross revenues at the production area point of shipment. The rate is 10% for licenses granted prior to 1973, and since then a sliding scale royalty has been applied, with rates from 8% to 16% as production goes from under 40,000 barrels per day up to over 350,000 barrels per day. The rates apply to total production from the field, not increments. The royalty is zero for fields licensed since 1986.

There are two similarly structured income taxes, a national income tax and a municipal tax. For petroleum, the latter is collected and utilized by the central government. The rates are 27.8% and 23%, respectively.

Exploration costs, license fees, and royalties are allowable deductions. Depreciation is figured on a six year straight line basis, commensurate with the expenditure.

Deficits accumulating over the previous 25 years are deductible as losses. The deduction in any year is limited to one-third of the total deficit in the previous 15 years, so that total deductions are distributed over a minimum of three years.

Only 50% of the losses from other activities in Norway can be deducted from petroleum income. There are no restrictions in setting petroleum losses against other income.

The Special Tax applies to offshore operations only. It is not deductible for income taxes.

The tax currently has a 30% rate. Its base is the same as for the income tax, except there is an additional special allowance of 6-2/3% of the value of capital expenditures (historical cost) (not including exploratory expenses) brought into use during the previous 15 years. For fields licensed since 1986 there is a 15% volume allowance.

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
Thru: William Floerchinger, Director
From: Charles Logsdon, Petroleum Economist CL
Date: April 25, 1988
Subject: The Petroleum Tax Structure of the United Kingdom
and Norway

The attached information contains general and detailed information about the tax structures of United Kingdom and Norway. Roger has drafted a very short summary of the two fiscal regimes. What follows is my own brief summary of the value issue which has a similar context to that we face here in Alaska.

UNITED KINGDOM

NORWAY

Oil Revenue Source:

- | | |
|--|---|
| 1. Royalty | 1. Production Fee (Royalty) |
| 2. Petroleum Revenue Tax
(Tax on production profit) | 2. Income Tax |
| 3. Corporate Income Tax
(Tax on trading profit) | 3. Special Petroleum Tax
(+ offshore income tax) |
| | 4. Capital Tax |

Value of Production:

- | | |
|--|--|
| 1. Arms length sales or market value. | 1. Norm price. Price fixed by a price board quarterly based on an assessment of what price would characterize "independent parties in a free market" |
| 2. Market value = evidential base of comparable arm's length sales | |
| 3. Market value : at time of delivery. Contracts for delivery in valuation month starting 1st day of month preceding delivery and ending on middle day of month of delivery. | |
| 4. Bonafide "3rd party" acceptable rather than calculated market value. See Brent Blend Exemption | |

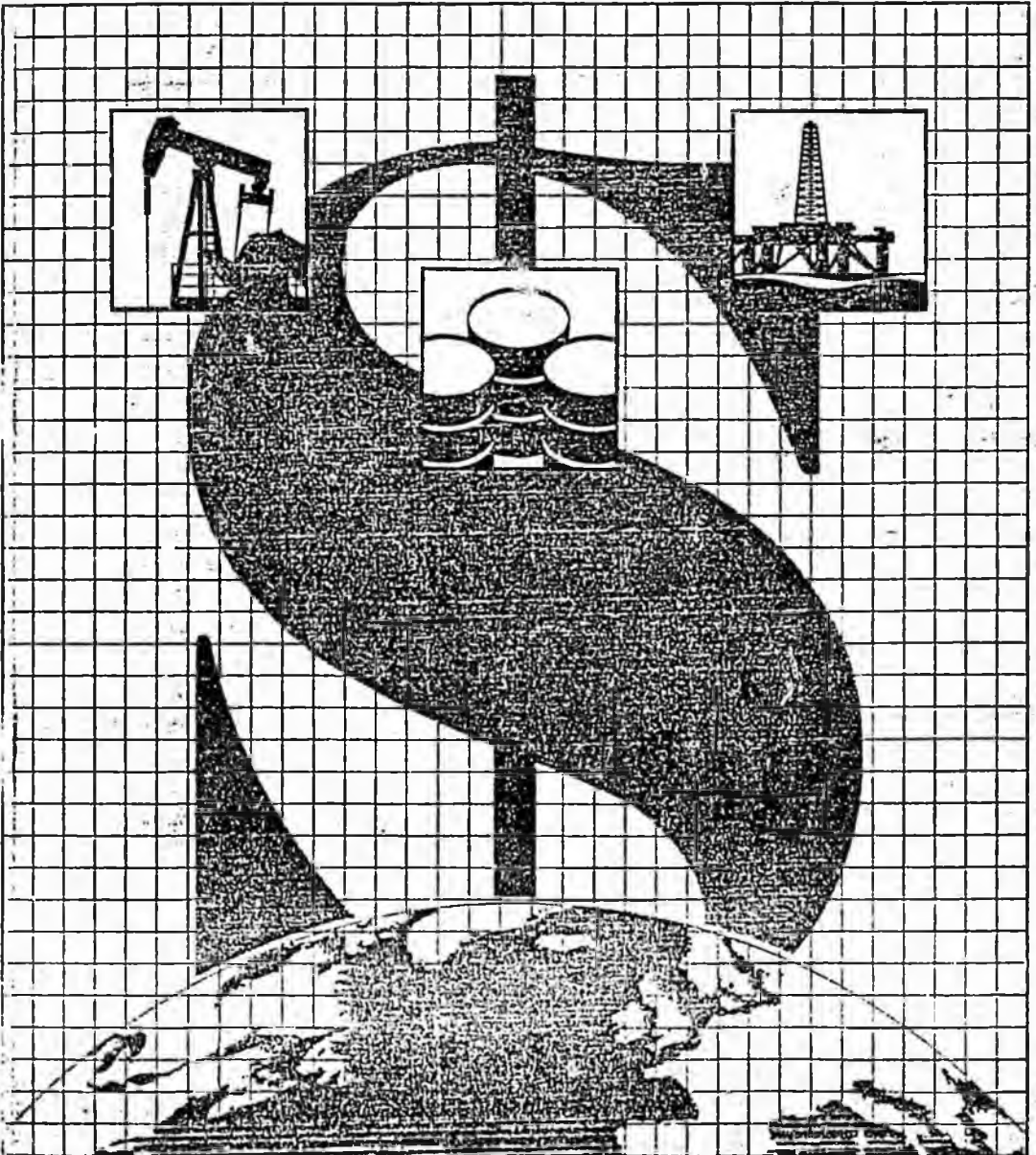
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DEPARTMENT OF REVENUE
OIL & GAS AUDIT DIVISION

PETROLEUM RENT COLLECTION

RECEIVED BY THE DEPARTMENT OF REVENUE



BY ALEXANDER KEMP WITH POSTSCRIPT BY CAMPBELL WATKINS

2) United Kingdom

In the United Kingdom petroleum rights are vested in the government by the Petroleum (Production) Act of 1934, which was extended to the U.K. Continental Shelf by the Continental Shelf Act of 1964. The great bulk of petroleum exploitation activity is offshore. Licences to explore for and produce petroleum are awarded through periodic licence rounds, of which there have been 10 to date. Blocks have usually been awarded by a discretionary system, though a number have been awarded by competitive cash-bonus bidding. Under the discretionary system, bids are assessed against a number of criteria which emphasize the technical and financial competence of the applicants and their contribution to the U.K. economy. Over the years greater attention has been paid to such criteria as the balance of payments, the growth of industry and employment, and the promotion of research and development work in the United Kingdom.

Special taxation of petroleum exploitation in the United Kingdom dates to 1975, when the Oil Taxation Act was passed. This Act ensured that three different taxes would be imposed on North Sea oil exploitation. The first was the traditional royalty which accrued to the state in the United Kingdom as landlord, the second was the Petroleum Revenue Tax, and the third was normal corporation tax.

The traditional royalty rate is 12½ per cent, but the effective royalty depends on the base to which the rate is applied. In the first licensing rounds the base was gross revenues at the wellhead; this was calculated from landed values less transport and initial treatment costs. The U.K. Inland Revenue in practice allowed as deductions from the landed price not only transport costs from the fields in the North Sea but also around 70 per cent of production platform costs, representing necessary initial treatment costs. Given the magnitude of these costs, the effective royalty as a proportion of the landed price could be reduced significantly below 12½ per cent. From the Fifth Licensing Round onwards, the base for the royalty has been changed, becoming 12½ per cent of the landed price. In the 1983 budget a major concession was made to stimulate development of new fields: for fields for which development approval is given from April 1, 1982, the royalty is abolished; this concession does not apply to fields in the southern basin (which have all been found to be gas, to date) and to onshore activities.

The Oil Taxation Act of 1975 introduced the Petroleum Revenue Tax (PRT) as a special tax on profits from North Sea oil exploitation. This tax is levied on a field-by-field basis. The original rate of tax was 75 per cent, and the base was gross revenues minus the sum of a number of allowances. The allowances were accrued field losses, operating costs, royalties, 175 per cent of the main field capital costs, field-related exploration costs, and an oil allowance equal to the value

of 10 million tons of oil (with no more than 1 million tons eligible for use as an allowance in any one year). Interest on loans was not allowed as a deduction, and as compensation for this the so-called "uplift" of 75 per cent of capital expenditure was introduced. The capital allowance deduction was allowed on a 100 per cent first-year basis.

Yak
incentive

The uplift and oil allowances were designed to give particular help to small and less profitable fields. Further help was provided by the safeguard and tapering (or annual limit) provisions. In broad terms these state that if gross profits in any year are less than 30 per cent of accumulated field investment, the PRT becomes zero; and the maximum PRT in any year is 80 per cent of the excess of gross profits over 30 per cent of field investment.

Since 1975 several changes have been made to the PRT. In the Finance (No. 2) Act of 1979 the rate of PRT was increased to 60 per cent as of January 1979. At the same time the uplift on capital expenditure was reduced from 75 per cent to 35 per cent and the oil allowance was reduced to 5 million tonnes, with no more than 0.5 million tonnes being allowed in any one year. As of November 1979, in the Petroleum Revenue Tax Act of 1980, the dates for payment of the PRT were advanced by two months. In the Finance Act of 1980, the rate of PRT was increased to 70 per cent as of January 1980.

Changes to some of the PRT allowances were introduced in the 1981 budget. From January 1981, the 35 per cent uplift on capital expenditure has been restricted to expenditure incurred up to the time when cumulative incomings from a field first exceed cumulative outgoings (field payback). For the purposes of this calculation, outgoings are defined to include any uplift on capital expenditure. Expenditure incurred after this cut-off period will not attract uplift.

The 1981 budget also saw changes to the safeguard and tapering provisions, introducing a restriction on the time period during which these concessions apply. The period is now half as long again as the time it takes for a field's payback to be achieved; the calculation is in terms of chargeable periods, each of which is six months, and outgoings are again defined to include any uplift on capital expenditure. Since eligibility for safeguard and tapering is calculated on a six-month chargeable period, instead of annually, from January 1, 1981, the maximum PRT payable in any period has thus become 80 per cent of the amount by which gross profits exceed 15 per cent of accumulated investment.

In the budget of 1981 the government also introduced a new tax, the Supplementary Petroleum Duty (SPD), with effect from January 1981. The rate of this duty was 20 per cent, with the base being gross revenues minus an annual allowance of one million tonnes. The duty, levied on a field-by-field basis and payable monthly, was deductible

for PRT and corporation tax. After much protest by the oil companies, the Chancellor of the Exchequer announced in his budget of March 1982 that the SPD would be abolished from the beginning of 1983.

The announcement of the abolition of SPD was accompanied by the raising of the PRT to 75 per cent and by the introduction of advance PRT (APRT), also to take effect from January 1983. The APRT was to be levied in exactly the same way as the SPD, with a rate of 20 per cent and a base of gross revenues minus an allowance of one million tonnes per year. The tax would thus take effect from the first day of production. Payments could be credited against normal PRT; where no PRT was payable, or where liability was insufficient to absorb all APRT, excess APRT would be carried forward and set off against future PRT. APRT payments would be included as deductions in computing the payback period for a field. Liability to APRT would be removed after five years of payment of the tax. Repayment of any APRT which had not been fully set off against normal PRT would also be made after five years of liability rather than at the end of field life. In the budget of 1982 plans were announced to phase out the APRT. The rate was reduced to 15 per cent for the period July-December 1984, 10 per cent for 1985, and 5 per cent for 1986; the tax was abolished at the end of 1986.

In the 1983 budget further major PRT concessions were made. Up to 1983, exploration costs had to be accumulated and could be set against income only from the field to which the exploration related. Only if the exploration was clearly abortive could the costs be set against other income for PRT purposes. Since 1983 exploration costs can immediately be set against any other PRT income and are deductible on a 100 per cent first-year basis. In the 1983 budget the oil allowance for new fields was doubled to 10 million tonnes, with a maximum of 1 million tonnes being deductible in any one year. This concession does not apply to the southern North Sea gas fields or to onshore fields.

In the Finance Act of 1987, further PRT concessions were made for fields outside the southern sector. The investor now has the option of utilizing a new crossfield allowance, equal to 10 per cent of development costs prior to field payback and applicable immediately against PRT income from other fields. No uplift is available on the expenditure to which the allowance relates. A further concession permits research and development costs not related to a specific field to be deducted from any PRT income after a three-year period.

Normal corporation tax applies to petroleum exploitation. Since 1974 there has been a one-way ring fence established around petroleum exploitation. This means that losses and capital allowances emanating from outside the ring fence cannot be set against income arising within the ring fence. On the other hand,

losses arising within the ring fence can be set against other, non-ring fence income.

The rate of corporation tax was 52 per cent from 1973 to April 5, 1983. For financial year 1983-1984 the rate was 50 per cent; for 1984-1985, 45 per cent; for 1985-1986, 40 per cent; from 1986-1987, 35 per cent. While the tax rates are being reduced, the rates of relief for investment in plant and machinery are also being reduced—from 100 per cent first-year basis up to March 14, 1984, when the rate became 75 per cent—to March 31, 1985, 50 per cent to March 31, 1986, and 25 per cent on a declining-balance basis thereafter. Relief for exploration and development drilling continues to be on a 100 per cent first-year basis. Losses, operating costs (including loan interest), royalties, and PRT are all allowable deductions, but the APRT is not an allowable deduction.

In this study the emphasis is on the operation of the fiscal system with regard to new investments. Accordingly, the system applicable to new fields has been incorporated in the detailed empirical work. This means that the provisions for royalty relief, the higher oil allowance for PRT, and the immediate relief for exploration costs are all included. Where immediate relief for exploration costs is taken by investors, the uplift benefit is forgone. This is the method that investors have preferred and so is included in this study.

Participation by the British National Oil Corporation (BNOC) has been a feature in some licences. For licences awarded under the first four rounds, participation was introduced retrospectively on a "voluntary" basis—BNOC was given the right to purchase 51 per cent of oil produced in the different fields. Thus, to quote from a famous speech of a government minister, Sir Harold (later Lord) Lever, at the time this was introduced in the mid-1970s, participation meant "no gain no loss" to the oil companies. Under the Fifth Round terms, BNOC was a compulsory equity partner, to the extent of 51 per cent, in all licences; it was also a full risk-sharing partner for both exploration and development costs, and so the arrangement is really a joint venture. Under the Sixth Round terms, BNOC's privileges were further increased—participation was on a carried-interest basis and the oil companies were asked to bid interests to BNOC of 51 per cent or more; exploration costs would be reimbursed only when a field was discovered and declared commercial. By the time the Seventh Round was announced (1980), there had been a change of government. The Conservative government removed BNOC's privileges, and BNOC had to compete for licences on the same basis as any other oil company, though it was still given the right to buy 51 per cent of all oil at market prices. In the Eighth Round the same arrangements as those of the Seventh prevailed. Since then the exploration and production interests of BNOC have been privatized in a new company,

Britoil. BNOB continued to exist as an oil purchaser and trader to the extent of 51 per cent of production until 1985, when the corporation was abolished. The Oil and Pipelines Agency was set up to maintain the right to purchase participation oil but these rights are not being exercised. Thus, in the present study no government participation is included.

The government has one discretionary fiscal power which it can utilize to foster the development of marginal fields. The Department of Energy can remit royalties where it is convinced that the requirement to pay royalties is discouraging the development of a field or causing premature abandonment to be considered. The remission of such royalties is free of PRT and corporation tax (i.e., no additional PRT or corporation tax is payable, even though royalties are normally deductible items for these two taxes). To date several applications for remission of royalties have been made, but none has been granted.

(3) Norway

The exploration and development of offshore petroleum in Norway is governed by the Continental Shelf Act of 1963, the Royal Decree of 1972 (as amended), and the Petroleum Activities Law of 1981. In Norway mineral rights are vested in the Crown. Licensing is done by a discretionary system, the criteria including technical and financial competence, contribution to the Norwegian economy (in particular the balance of payments and industrial growth and development), exploration program offered, and government participation offered. There are three main taxes levied on petroleum exploitation, namely, royalty, income tax, and Special Tax.

As in the United Kingdom, the royalty is part of the licence. The base of the royalty is gross revenues at the production-area point of shipment. For licences awarded before December 1972, the rate is 10 per cent; for licences awarded since December 1972, a progressive schedule of royalty rates applies, as shown in Table 3.4. The rates apply to the *total* production from a field. The tax is thus applied on a slab basis, not an incremental one. The rules also state that when production from a field declines, the royalty rate will fall as well, according to the schedule, except that it may *not* fall below 12 per cent. On gas the royalty rate is fixed at 12½ per cent. Section 26 of the Royal Decree of December 1972 gives the government the power to fix lower royalty rates "if the sea depth, capacity per well, or other conditions so require," but to date there have been no reductions in royalty rates.

There are two income taxes payable by all companies operating in Norway—National Income Tax, at the rate of 27.8 per cent; and Municipal Tax, at the rate of 23 per cent. With regard to petroleum,

the Municipal Tax is collected and utilized not by the local governments but centrally. In 1975 the Norwegian government introduced a tax package on North Sea operations which maintained the royalty provisions described above but substantially changed income taxation.

Table 3.4
Royalty Rates on Oil Production in Norway

Average Field Production (barrels per day)	Rate of Royalty (%)
Under 40,000	8
40,000 and under 100,000	10
100,000 and under 225,000	12
225,000 and under 350,000	14
350,000 and above	16

The 1975 act introduced allowances which apply equally to both income taxes. Deficits accumulated over the previous 25 years are deductible as losses, although there is a restriction on the rate at which such losses can be deducted. The deduction in any one year is limited to one third of the total deficit in the previous 15 years, so that the total deductions have to be distributed over a minimum of 3 years. Eligible costs include exploration costs, various licence fees, and royalties. Only 50 per cent of losses incurred from other (non-Continental Shelf) activities in Norway may be deducted from Shelf income. Had the 1975 act not stipulated this restriction, companies would have an incentive to invest in non-Shelf activities, and tax revenues from North Sea oil exploitation would be postponed. The provision means, in effect, that 50 per cent of non-Shelf operating losses may be set against Shelf income, as can 50 per cent of the costs of investing in, say, a refinery or marketing facilities. On the other hand there is no restriction on the ability to set losses incurred in Shelf operations against income from other activities in Norway. Thus, there are still advantages to be obtained from integrated operations in Norway. However, losses or deficits incurred abroad are not allowed as deductions against North Sea income in Norway.

The 1975 act also introduced special depreciation provisions for North Sea operations. The normal depreciation allowances were considered too restrictive for the size of the investments and risks

incurred in the North Sea, and the additional or initial allowances available in existing income-tax legislation were not considered suitable. Accordingly, new provisions were introduced. These stated that deductions for capital expenditure incurred in production and transport facilities could be claimed to the extent of 16 $\frac{2}{3}$ per cent per annum from the date at which the assets were brought into use. Thus, a six-year straight-line depreciation system was introduced, but it effectively commenced only when oil production started. This last qualification has been of considerable significance. It has meant that, when an enterprise was in receipt of income from a field in the North Sea and was in a tax-paying position, it could not immediately set depreciation allowances relating to a new field against the income from its existing operations; such offsetting was not allowed until production from the new field started. There is no ring fence around each field in Norway, but the way in which the depreciation allowances were given produced a rather similar effect.

The most widely publicized innovation in the 1975 act was the Special Tax, which applies only to offshore operations. The tax was introduced at the rate of 25 per cent. The base for this tax is the same as that for income tax, with important modifications. In addition to the depreciation and other allowances for income tax discussed above, there is a further special allowance. In the 1975 act the special allowance, in any one year, was equal to 10 per cent of the value of capital expenditure (at historic cost) on offshore activities brought into use over the preceding 15 years. Capital equipment includes investments in transport systems and related terminal facilities; exploration expenditure is not allowed as part of the special allowance. If production from a field lasted 15 years, the total value of the special allowance for that field would thus be 150 per cent of the value of capital expenditure. The special allowance does not come into effect until production from the field has actually started. This is important when the tax implications of a second field are being analyzed: the ability to utilize the special allowance from the capital expenditure on the second field against the income of the first field is restricted to the time when production commences on the second field. If a field's producing life is less than 15 years—and this is likely to be the case for many of the smaller fields—then, of course, the full allowance of 150 per cent of capital expenditure cannot be utilized. Such unutilized allowances from one field may, however, be carried over and used when calculating the tax base for Special Tax on a second field. This is because there is not, strictly speaking, a ring fence around each field for Special Tax purposes.

Special Tax is not deductible for income-tax purposes. In June 1980, the fiscal system in Norway was revised, with the changes mainly relating to the Special Tax. The rate was increased from 25

per cent to 35 per cent. In addition, the special allowance in any one year was reduced to 6 $\frac{2}{3}$ per cent of accumulated investment over the previous 15 years. It was made clear, however, that the equivalent of 100 per cent of capital costs would always be allowable over the life of a field even when strict application of the rule would not suggest eligibility for such a total; this was a concession to help short-lived fields. The 1980 rules stated, however, that utilization of the special allowance could not begin until one year after production starts. A further change stipulated that all losses would now be eligible for write-off whenever sufficient income becomes available. There was a change concerning the timing of payment of both income taxes and the Special Tax—before 1980 a lag of around 12 months occurred between the liability for these taxes and their actual payment; this lag is now been reduced to 6 months.

In the summer of 1986 major concessions were made to the fiscal system. From January 1, 1987, the rate of Special Tax was reduced to 30 per cent, and as of that date depreciation for both Special Tax and income tax commences from the time that the expenditure is incurred. Uplift is no longer available on capital expenditure after January 1987 but, as a transitional measure, uplift on past expenditure continues according to the old rules. For new fields (development approval since January 1, 1986) royalties are reduced to zero. Further, for Special Tax on new fields a volume allowance equal to 15 per cent of production is now available.

The fiscal position regarding dividend payments is complex, the distinction between National Income Tax and Municipal Tax being highly significant. When a company makes a distribution, the dividend payment is deductible from the National Income Tax but not from Municipal Tax, and dividend payments are not deductible for Special Tax. When a dividend is declared, Norwegian shareholders pay income tax on the dividend. When the distribution is made by a Norwegian subsidiary to its foreign parent, a special withholding tax is paid. The rate of withholding tax is determined by the double tax agreements between Norway and the foreign countries concerned; on subsidiaries of U.S. and U.K. companies the rate is currently 15 per cent.

In Norway joint-stock companies are obliged to maintain a reserve fund, whose minimum required amount is the higher of 20 per cent of the company's share capital or that amount which, when added to the share capital and revaluation fund, equals the company's debt. If the defined minimum has not been attained, then the company has to set aside funds according to the following rules:

1. Amounts equal to 10 per cent of annual profits, the latter defined as excluding any part of profits required to cover losses from previous years.
2. A further amount equal at least to any dividend declared by the company in excess of 10 per cent of the sum of the share capital, revaluation fund, and reserve fund at the beginning of the financial year.
3. Any share-subscription premium less the costs of establishing the company or increasing its capital.

Contributions to the reserve fund are, of course, made before payment of taxes. This reserve-fund legislation restricts the ability of a company to pay dividends.

Given the tax regulations and rates discussed above, it is important to clarify the dividends that can be paid. The maximum dividend payable may be calculated in the following manner (ignoring reserve-fund contributions and the capital tax, which is very small):

$$\begin{aligned}
 \text{Maximum Dividend (MD)} &= \text{Profit before tax (P)} - \text{Special Tax (ST)} - \text{National Income Tax (NIT)} - \text{Municipal Tax (MT)} \\
 &= P - ST - 0.278(P - MD) - 0.23(P) \\
 &= 0.492(P) - ST + 0.278(MD) \\
 &= \frac{0.492(P) - ST}{0.722}
 \end{aligned}$$

When maximum dividend is paid, the various corporate taxes payable in 1987 are as follows:

$$\begin{aligned}
 \text{NIT} &= 0.278(P - MD) \\
 \text{MT} &= 0.23(P) \\
 \text{Dividend Tax (DT)} &= 0.15(MD) \\
 &(\text{for United States and United Kingdom}) \\
 \text{ST} &= 0.30(P - \text{Special Allowance})
 \end{aligned}$$

Oil companies operating on the Continental Shelf, like other enterprises on land, pay a further tax—the capital tax. For many years this was at the rate of 0.7 per cent of the value of net capital, but the rate has been progressively reduced in recent years and it is now 0.4 per cent. The base includes production, transport, and storage facilities; stocks of products produced; and securities and bank deposits. As far as offshore operations are concerned, the base does *not*

include the value of crude oil in the reservoirs. The capital tax is not deductible for income-tax or Special Tax purposes.

Participation by the national oil company, Den Norske stats oljeselskap a.s. (Statoil), has taken place since the company was founded in 1972. In early participation schemes, some "net profit" agreements were concluded, but for some years now carried-interest agreements have been preferred. Statoil's interest is carried by the oil companies until a commercial discovery is made, at which point Statoil participates. In early agreements, Statoil agreed to pay its share of exploration costs. In most later agreements only development and operating costs were payable by Statoil, though in recent agreements with other Norwegian oil companies it has agreed to pay its share of exploration costs.

In early participation agreements there was a fixed, flat Statoil share. From the Third Licensing Round up to the Tenth Round participation agreements were concluded on a sliding-scale basis, which means that Statoil's share of *total* production increases with the size of peak production from the field. The procedure adopted is that Statoil's share is estimated at the time when a field is declared commercial; if the initial estimates prove accurate, then Statoil's interest would remain constant throughout the life of the licence; on the other hand, if estimated peak production is subsequently changed, Statoil's share would be retroactively altered. There might, of course, be several such retroactive adjustments.

The precise scales are the subject of negotiation between the oil companies and Statoil and are generally not published. A typical scale in the second half of the 1970s or early 1980s would give Statoil a minimum share of 50 per cent, increasing according to the schedule shown in Table 3.5. By the Seventh, Eighth, and Ninth Rounds the sliding scales had become truncated and the scale shown in Table 3.6 was reported as typical.

By 1983 there was growing concern about the enormous direct role that Statoil was playing in the whole economy. The Mellbye Committee was set up and eventually in October 1984, new regulations regarding participation were introduced whereby the state took a direct share in new fields and Statoil was given a reduced role, as is illustrated in Table 3.7. The total government share was to remain unaffected.

By the time of the Tenth Round (1985-1986) oil prices were falling. In an attempt to retain investor interest, participation rates have been reduced. Under this round the total state share is in the 60 to 65 per cent range, with Statoil having a direct stake of 20 per cent on average. In the summer of 1986, a further concession was introduced—on new licences investors are no longer obligated to carry the state's share at the exploration stage.

Table 3.5
Statoil Participation - Typical Sliding Scale

Maximum Licence Producing Rate (thousands of barrels per day)	Statoil Working Interest (%)
0 - 75	50
75 - 100	52
100 - 125	54
125 - 150	56
150 - 170	58
170 - 190	60
190 - 200	61
200 - 210	62
210 - 230	63
230 - 250	64
250 - 270	65
270 - 290	66
290 - 310	67
310 - 330	68
330 - 350	69
350 - 370	70
370 - 390	72
390 - 410	74
410 - 430	76
430 - 450	78
450 and above	80

Table 3.6
Typical Statoil Participation, Recent Rounds

Peak Production (thousands of barrels per day)	Rate of Statoil Participation (%)
0 - 100	65
100 - 250	75
250 and above	80

Source: Norges Offentlige Utredninger, *Organiseringen av statens deltagelse i petroleumsvirksomheten* (Oslo: Universitetsforlaget, 1983), p. 42.

Table 3.7
Estimates of Likely Structure of Norwegian State Participation, Selected New Fields

Field	Direct State Share (%)	Statoil Share (%)
Sleipner	30	25.8
Oseberg	49.24	14
Troll 31/2	54	21
Troll (rest)	73	12
Gullfaks	73	12

(4) Indonesia

In Indonesia the basic legal framework for petroleum exploitation is contained in the Oil and Gas Law of 1960, Law No. 1 of 1967, the Foreign Investment Law, Law No. 11 of 1967, and Law No. 8 of 1971. Other relevant legislation is contained in presidential and ministerial decrees. The Oil and Gas Law of 1960 abolished the concession system. Law No. 8 of 1971 established the state company, Pertamina, and permitted it to enter into production-sharing agreements with foreign oil companies.

Indonesia has been the pioneer of production-sharing agreements whereby the oil companies are contractors to the state oil company. In the Indonesian agreements contractors pay both signature and production bonuses. The details of these vary from one contract to another with figures in the range \$1 to \$5 million being typical. Production bonuses vary with the level of production. This study has assumed bonuses of \$5 million at 20,000 barrels per day (b/d), \$10 million at 50,000 b/d, \$20 million at 100,000 b/d, and \$40 million at 200,000 b/d. Bonuses are not recoverable costs under the production-sharing scheme. They are deductible for income-tax purposes, but they are grossed up in order not to reduce the government take.

For cost-recovery purposes, under the production-sharing scheme, exploration costs and intangible drilling costs have been deductible as soon as income from the contract area in question permits. Tangible capital costs have been recoverable in the form of depreciation, which is allowed over one half of the depreciation life by the double-declining-balance method. The contractor has the option to switch to the straight-line method whenever it is advantageous. There is a one-time investment tax credit equal to 20 per cent of tangible development costs. The credit is deducted from gross production before production sharing takes place.

After cost recovery and investment tax credit, the remaining oil has usually been split 65.9091:34.0909 (on a per-tax basis) in favour of Pertamina; on a post-tax basis this has been equivalent to 85:15 in Indonesia's favour. There have been some divergences from this figure—for example, a major agreement with Caltex in late 1983 provided for an 88:12 split.

In Indonesia, contractors have been obliged to provide a certain amount of production for the domestic market on preferential terms. The maximum obligation has been 25 per cent of the contractor's pre-tax share. For the first five years of production from a contract area, the oil can be sold at full market value but after that a figure of only \$0.20 per barrel can be charged. During 1986, as an incentive to investors, this domestic-market obligation was abolished for new agreements.

Contractors have to pay corporate income tax on their taxable profits. Operating costs, exploration costs, tangible drilling costs, and depreciation are all deductible in order to obtain taxable income. Until recently the corporate tax rate was 46 per cent. There is another tax, known as the Tax on Interest, Dividends and Royalties, which is payable regardless of whether dividends have been remitted or not. This is at the rate of 20 per cent of profits after corporation tax. There has thus been a combined tax payable of 56.8 per cent $[0.46 + 0.2(1 - 0.46)]$.

In 1984 the income tax in Indonesia was reformed.² The corporate rate was reduced to 35 percent, so the combined rate is thus 48 per cent. Depreciation terms were also changed; for many items of equipment employed in petroleum exploitation, rates of 25 per cent on a declining-balance basis are available with some items having rates of 10 per cent. Intangible drilling costs continue to be expensed. Although the new tax law took effect from January 1984 onwards, exploration agreements in 1984 and in 1985 were signed under the old terms.³ The precise application of the new laws to petroleum contracts remains unclear. The government does not wish its total take to be decreased as a consequence of the change in income-tax rate. For the government's take to remain unchanged would imply a pre-tax oil-sharing split of 72:28 in Indonesia's favour. This ratio, as well as the 65.9091:34.0909 one, has been employed in the present study.

In Indonesia the rules require investors to set up separate companies for each contract area, and each company is assessed separately for income tax. The production-sharing arrangements are of course also on a contract-area basis. It follows that there are no significant fiscal advantages from ongoing investment, although if more than one field were discovered in one contract area, there would be significant advantages when the second field was developed.

(5) Malaysia

Under the 1974 Petroleum Development Act, petroleum concessions in Malaysia were terminated and replaced by production-sharing agreements. The national oil company, Petronas, was established and given exclusive rights to explore for and produce petroleum and to negotiate production-sharing agreements with oil companies.

The current fiscal package in Malaysia consists of production-sharing arrangements as well as royalty, income tax, Export Tax, Excess Proceeds Tax, and contribution to a research fund. There are also a number of bonuses payable—signature bonuses, which have averaged around \$1 million in recent years; discovery bonuses, which have been around \$2.5 million per commercial discovery in recent

(2) United Kingdom

The state's shares of economic rents under price scenarios expected in 1985 are shown in Figure 6.13 for a 10 per cent discount rate. The fiscal system is seen to behave such that under rising real prices the take is progressive across most of the fields and proportional on the VLV one. The absence of royalties on new fields combines with the effects of some features of both the PRT and corporation tax systems to produce this result. A combination of the "uplift" and safeguard provisions for PRT ensure that this tax is progressive in money-of-the-day terms and sometimes in present-value terms. For an ongoing investor the ability to offset rapidly at least some of the costs of a new field development against other income produces a progressive income tax when profitability is reasonably high. The net result is a system which is progressive in relation to changes in profits caused by cost increases.

The same features ensure that at relatively low cost levels the fiscal system is progressive in relation to changes in profits caused by oil price movements. Unfortunately, in the range of costs now most likely to be found in the U.K. North Sea (namely, MC to HC), the fiscal system becomes regressive in relation to oil price changes; by the time HC is reached, the take is highest under falling real oil prices and lowest with rising real prices.

At a discount rate of 15 per cent the picture, as shown in Figure 6.14, is different. The fiscal system is highly regressive with respect to both oil prices and cost changes especially in the MC to HC range, which typifies present conditions. The allowances for PRT and corporation tax are insufficiently strong to prevent the government take from rising strongly as profitability falls. The reliefs for drilling costs are on a 100 per cent first-year basis and for plant and machinery costs at 25 per cent on a declining-balance basis; together they are too slow to prevent the take from increasing rapidly in a situation of falling real prices and rising costs.

From the trends discussed above it is no surprise to find that the system becomes more regressive in discounted terms under collapsed oil prices. Figure 6.15 shows the effects with a 10 per cent discount rate. Perhaps the most remarkable finding is that under MC conditions the system still produces takes well below 100 per cent of the economic rents. Even at a 15 per cent discount rate the takes under MC conditions remain tolerable on the LV field (84.7 per cent) and the VLV one (47.9 per cent).

The U.K. system is an adaptation of a conventional fiscal system. For an ongoing investor it is seen that, despite its many complexities, it produces an effect which encourages field developments over a wide range of oil price and cost conditions. The system does not always collect economic rents in a very accurate fashion, but compared with

many others in this study it is reasonably flexible to changes in the operating environment. The U.K. system has imperfections emanating from the basic problem that the chosen instrument is only indirectly related to its target: the appropriate target is the net present value at the investor's discount rate, and the U.K. fiscal system relates to this at best in a cumbersome manner, and at worst inaccurately.

Table 6.4 shows the position of the explorationist in the U.K. sector contemplating a program of \$20 million on an ongoing basis for a constant real oil price of \$27. The results show that, with a 1 in 5 chance of discovery, pre-tax EMVs are positive except at a discount rate of 15 per cent. With a chance of 1 in 10 the result is positive only at discount rates below 10 per cent, while with a chance of only 1 in 20 there is no positive EMV at any positive discount rate. The post-tax position generally reflects the favourable fiscal treatment given to exploration expenditure by an ongoing investor in the United Kingdom. Effective tax takes are low because the expected fields are small in size and pay little PRT. Exploration costs are relieved at 83.75 per cent on a 100 per cent first-year basis; in the calculations, this front-end relief to the ongoing investor is regarded as a negative tax. The ongoing investor also obtains the benefit of front-end relief for corporation tax on his expenditure on new field development. When the discounting process is undertaken, the effective tax take can sometimes be negative. This is especially the case when the subsequent tax payments on a discovered field are very small. The fiscal system is certainly helpful to ongoing investors.

In the U.K. sector, exploration programs of amounts larger than \$20 million are not uncommon. With a program of \$60 million it was found that pre-tax EMVs were negative at all discount rates when the chance of success was 1 in 10 or worse; with a 1 in 5 chance of discovery the EMV was positive at discount rates below 10 per cent. Effective tax rates (as defined above) were generally low in discounted terms and on some occasions negative. Thus, exploration incentives were hardly impaired by the tax system when viewed in discounted terms.

Under the collapsed oil price with an exploration program of \$20 million, pre-tax EMVs are nearly always negative on the overall discovery rates of 1 in 5, 1 in 10, or 1 in 20, but the size of the negative EMV increases sharply as prospectivity declines. Post-tax EMVs are thus also generally negative as well. However, the fiscal system is, for the most part, not the main deterring factor; exploration incentives are low primarily because of the low level of oil prices in relation to likely exploitation costs. To an ongoing investor, effective tax rates are generally low and in discounted terms the tax system—with its

loss-sharing provisions resulting from the front-end loading of reliefs for expenditure—can hardly be said to be a deterrent.

Table 6.4
United Kingdom Expected Monetary Values and Government
Takes facing Explorationist, \$20 Million Program
Constant Real Oil Price (\$27)

Real Discount Rate (%)	Expected Monetary Values (US\$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	122.4	77.3	29.1
5	51.4	36.1	23.6
10	10.6	12.1	-ve
15	-13.3	-2.2	-ve
Overall Discovery Rate: 1 in 10			
0	51.2	36.6	17.8
5	15.2	15.5	-ve
10	-5.7	3.0	-ve
15	-18.2	-4.5	-ve
Overall Discovery Rate: 1 in 20			
0	15.6	16.3	-ve
5	-2.9	5.2	-ve
10	-13.9	-1.5	-ve
15	-20.7	-5.6	-ve

Note: -ve indicates the tax take is negative.

In sum, from the viewpoint of economic efficiency, the U.K. fiscal system performs reasonably well when applied to new investments. The system is profit-related and does take account of differences in cost conditions likely to be encountered in the North Sea. Differences between pre-tax and post-tax rates of return are modest in comparison with many other countries discussed in this study. Reliefs for

exploration are fairly generous, and incentives for new exploration are comparatively strong. The U.K. system is noteworthy for the extent to which exploration risks are shared by the government. Development costs are also shared to a significant extent. The fiscal system is only indirectly related to the target of economic rents, however, and this inevitably produces some lack of accuracy. The PRT is very complex, and therefore costly, and the need to make some discretionary modifications as the operating environment changes is a further drawback.

Figure 0.13
United Kingdom
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

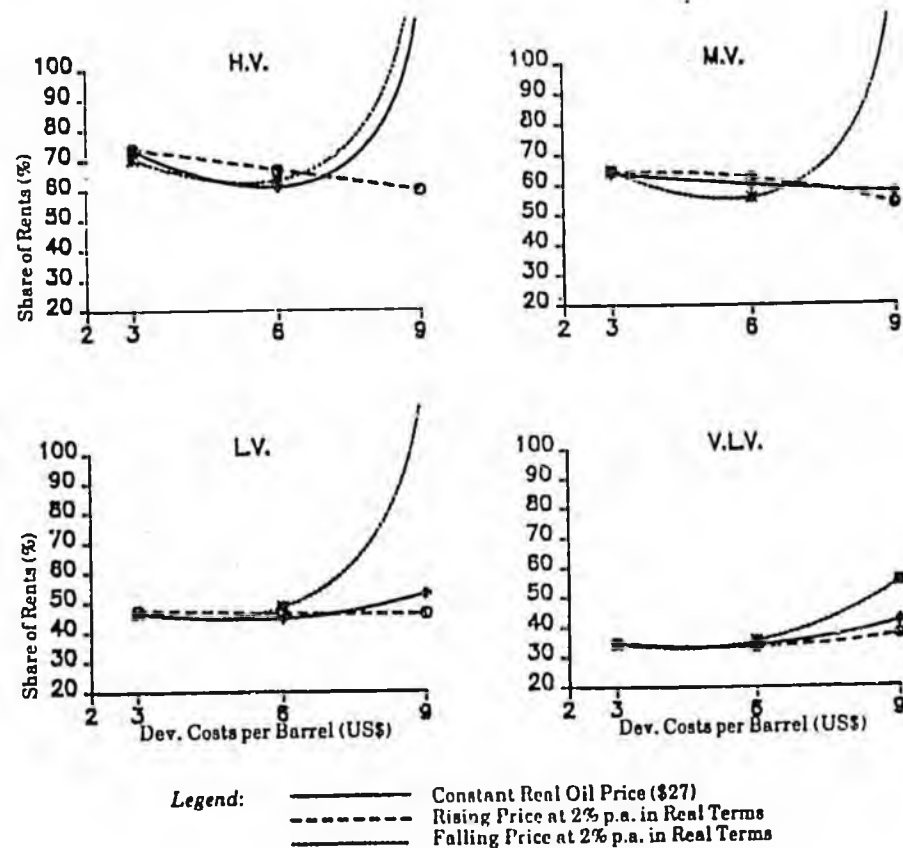
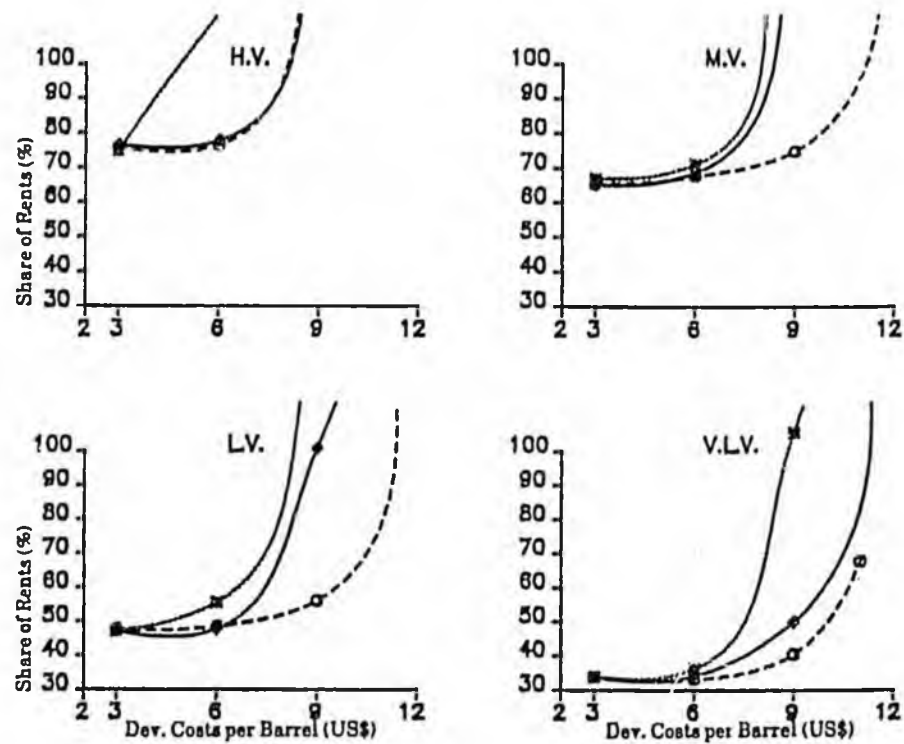
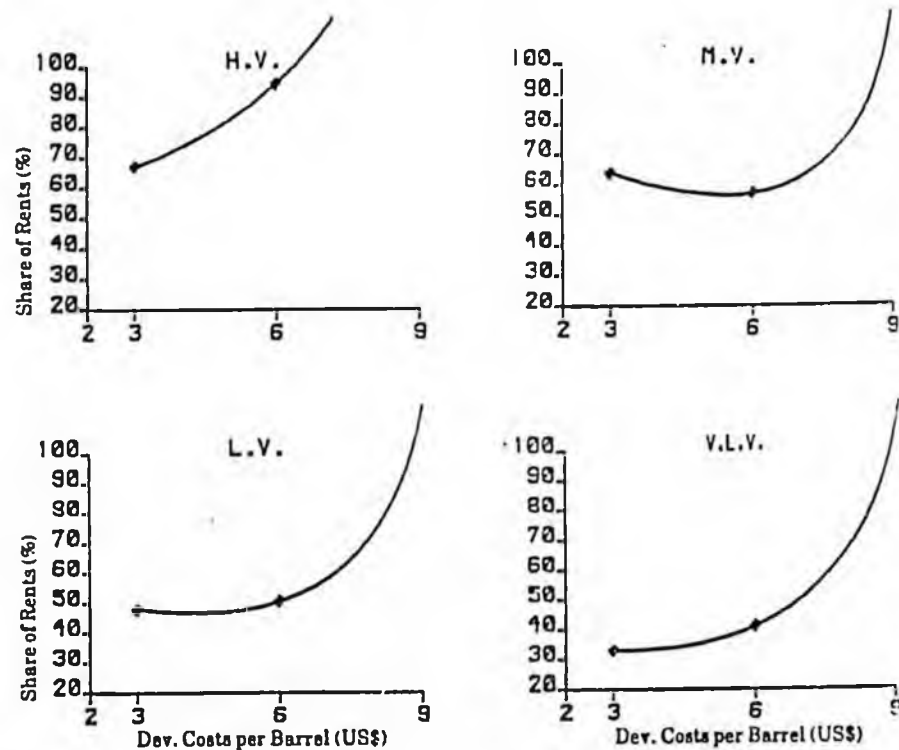


Figure 6.14
United Kingdom
Government Share of Economic Rents, 15% Real Discount Rate
1986 Price Perspectives



Legend:
 ——— Constant Real Oil Price (\$27)
 - - - - - Rising Price at 2% p.a. in Real Terms
 Falling Price at 2% p.a. in Real Terms

Figure 6.15
United Kingdom
Government Share of Economic Rents, 10% Real Discount Rate
Collapsed Real Oil Price



(3) Norway

The share of economic rents accruing to the state from petroleum exploitation in Norway is shown in Figures 6.16 and 6.17. Both figures illustrate the working of the Norwegian system under the oil price perspectives of 1985, at a discount rate of 10 per cent, but Figure 6.16 includes the government's take from taxes only, while Figure 6.17 includes state participation.

Figure 6.16 shows that the tax system is regressive and can collect more than 100 per cent of the rents. Projects will generally have development costs in the \$3- to \$6-per-barrel range, though some have considerably higher cost levels. It is seen that post-tax returns exceeding 10 per cent are sometimes not available when development costs attain \$6 per barrel. On all fields the takes increase with lower oil prices. Similarly, the takes rise as project profitability falls due to cost increases. Several features of the fiscal system bring about this result—depreciation provisions for development costs for both income tax and Special Tax are on a six-year straight-line basis commencing with the year in which expenditure is incurred; this makes the system regressive in present-value terms, while the high marginal and average rates produce the high overall takes.

The position with government participation added (Figure 6.17) shows that with development costs of \$3 per barrel participation significantly increases the state's share of economic rents. However, at development costs of \$6 and more, the state's total share actually goes down compared with the tax-only situation, because the state company is then sharing in the project's post-tax present-value losses; in these situations the state would be better not to participate at all.

The fiscal system becomes both more severe and regressive the higher the discount rate employed. In Figure 6.18 the state's take (including participation) is shown at a 15 per cent discount rate. The difference between the take under falling real prices and that under rising prices becomes distinctly more marked. Under falling real prices the take is seen to become dramatically regressive and severe, on the large fields in particular.

As was discussed in Chapter 3, the institutional framework in Norway—with the dominant role of Statoil in investment decision making—suggests that the effective discount rates employed in project appraisal could be lower than in other countries, where private-sector firms are less inhibited. It is thus useful to consider the effects of the Norwegian fiscal system at lower discount rates. At a 5 per cent rate, on the assumption of constant real oil prices at \$27 per barrel, the tax take on the VIIV field is 73.9 per cent at LC and 79.0 per cent at MC conditions; on the IIV field it is 73.6 per cent and 77.2 per cent respectively; on the MV field, 81.1 per cent and 76.7 per cent respectively; on the LV field the take is 73.4 per cent at LC, 76.2 per

cent at MC, and 84.7 per cent at IIC conditions. The conclusion that the size of discount rate employed makes a considerable difference to government takes in the Norwegian system is thus reinforced. If effective discount rates in Norway are lower than in other countries, there could be a significant effect on incentives.

Under the collapsed-price scenario the system is highly regressive in present-value terms. With development costs of \$3 per barrel, the tax takes are around 80 per cent on all sizes of fields; as costs increase, the take rises sharply. The position with a discount rate of 10 per cent (participation included) is shown in Figure 6.19. At development costs of \$6 per barrel the takes clearly exceed the rents. With a 5 per cent discount rate, tax takes are under 90 per cent under LC conditions on all fields; under MC conditions the takes are 85.4 per cent on the MV field, 83.8 per cent on the LV, and 83.3 per cent on the VL^V one.

The position facing an explorationist in Norway contemplating a program costing \$20 million, under the 1985 oil price perspective, is shown in Table 6.5. The pre-tax and participation EMVs are positive at all discount rates apart from the 15 per cent one. The expectation of relatively large fields in the Norwegian sector is a main factor in the determination of the positive outcomes. After tax and state participation, expected returns are usually reduced markedly by the fiscal system—EMVs to investors are now negative at positive real discount rates when chances of success are 1 in 10 or 1 in 20. The government shares to a large extent in the exploration risks through high and rapid write-off for exploration costs. This provides some compensation for the high tax takes on discovered fields. At high discount rates and very unfavourable prospectivity, the front-end relief for exploration can be so influential that the overall expected tax take becomes negative. Prospectivity in Norway is comparatively high. Many investors anticipate a discovery chance of at least 1 in 5. This helps to explain the continuing interest in this country.

For an exploration program of \$60 million, pre-tax EMVs are negative under all levels of prospectivity at a discount rate of 15 per cent. With success rates of 1 in 10 or less, pre-tax EMVs are negative with discount rates of 10 per cent, while post-tax EMVs become negative at real discount rates of 5 per cent. With a 1 in 5 success rate the post-tax EMVs are positive at a 5 per cent discount rate. The expected tax takes would often exceed 100 per cent of the expected rents.

The explorationist executing a program costing \$20 million under the scenario of collapsed oil prices faces pre-tax EMVs that are negative at discount rates of 10 per cent and above when chances of success are 1 in 5, or worse. On a post-tax basis, EMVs are negative at discount rates of 5 per cent. The government again shares to a

marked extent in the exploration losses by giving immediate relief for these costs to the ongoing investor for both income tax and Special Tax.

Table 6.5
Norway (State Participation Included)
Expected Monetary Values and Government Takes facing
Explorationist, \$20 Million Program
Constant Real Oil Price (\$27)

Real Discount Rate (%)	Expected Monetary Values (US\$ million, 1986)		Government Take (%)	
	Pre-Tax	Post-Tax and Participation	Tax	Total
Overall Discovery Rate: 1 in 5				
0	572.8	42.6	71.2	90.4
5	245.6	12.6	79.4	93.9
10	79.8	-2.3	100.8	103.2
15	-6.1	-9.7	261.2	174.3
Overall Discovery Rate: 1 in 10				
0	276.4	19.9	70.5	90.6
5	112.3	4.8	78.6	94.8
10	28.9	-2.7	106.7	110.0
15	-14.6	-6.5	-ve	-ve
Overall Discovery Rate: 1 in 20				
0	128.2	8.5	68.9	91.1
5	45.6	0.9	76.5	97.5
10	3.4	-2.9	-	-
15	-18.9	-4.9	-ve	-ve

In sum, the Norwegian fiscal system is not sufficiently flexible to cater for the range of operating circumstances likely to be found without economic inefficiencies emerging. The reformed system of state participation, while more profit-related than the previous one, is not sufficiently sensitive to changes in profitability, whether from oil price movements or cost changes. Given that it has a high marginal rate, the system is not well enough related to economic rents. When moderate rates of depreciation and high rates of tax are combined in a tax structure, it is extremely important to ensure that the system is accurately targeted if it is to perform in an efficient manner.

Figure 6.10
Norway (Tax Only)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

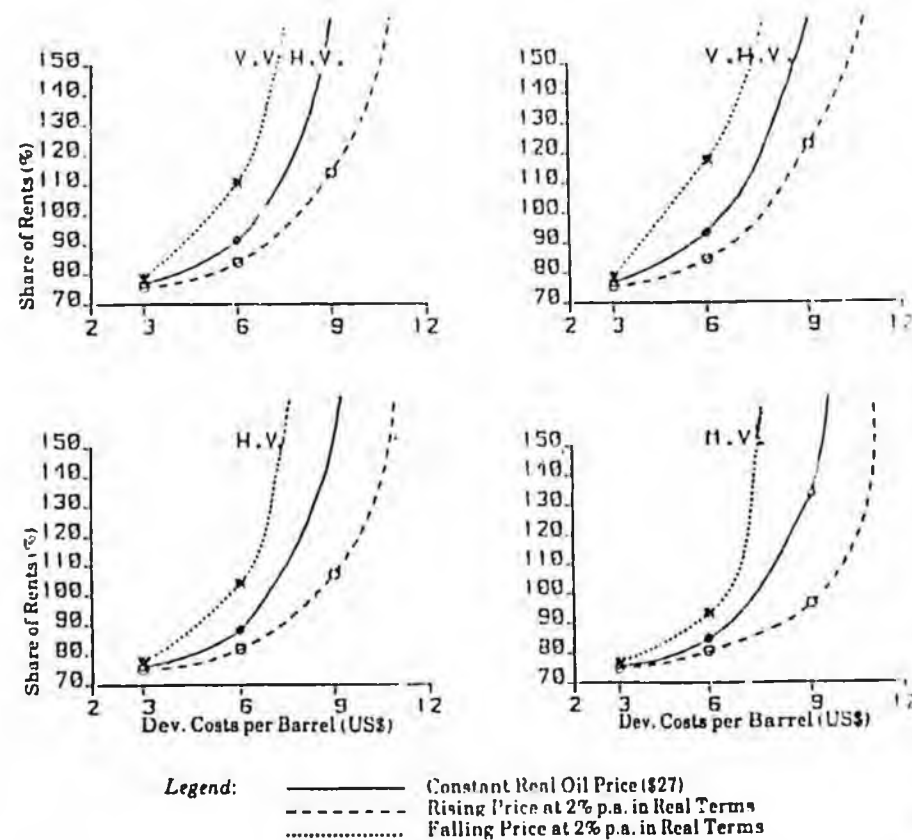
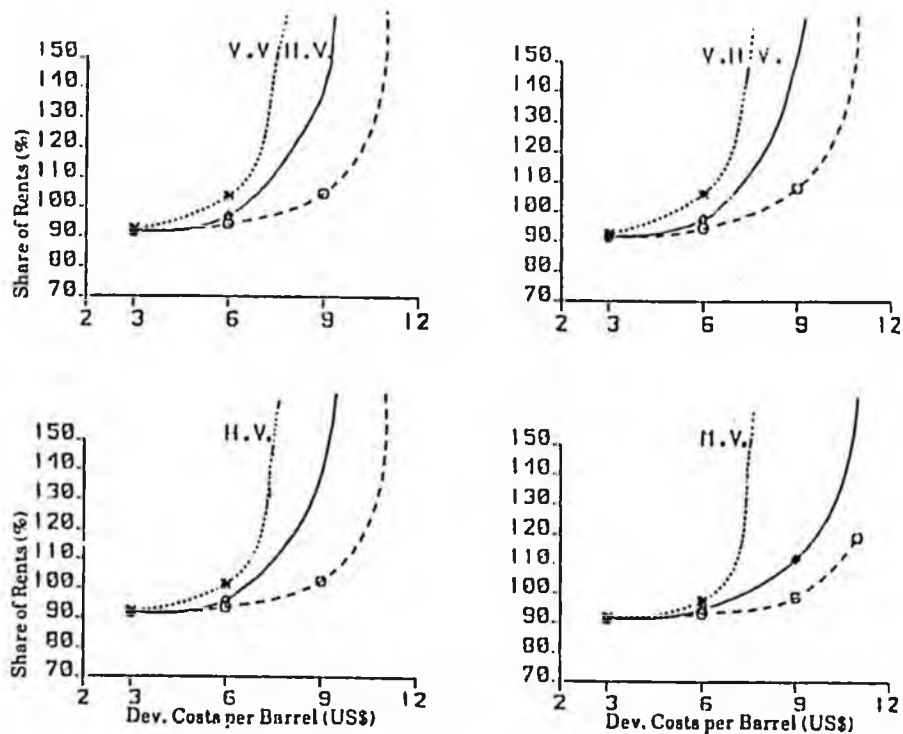
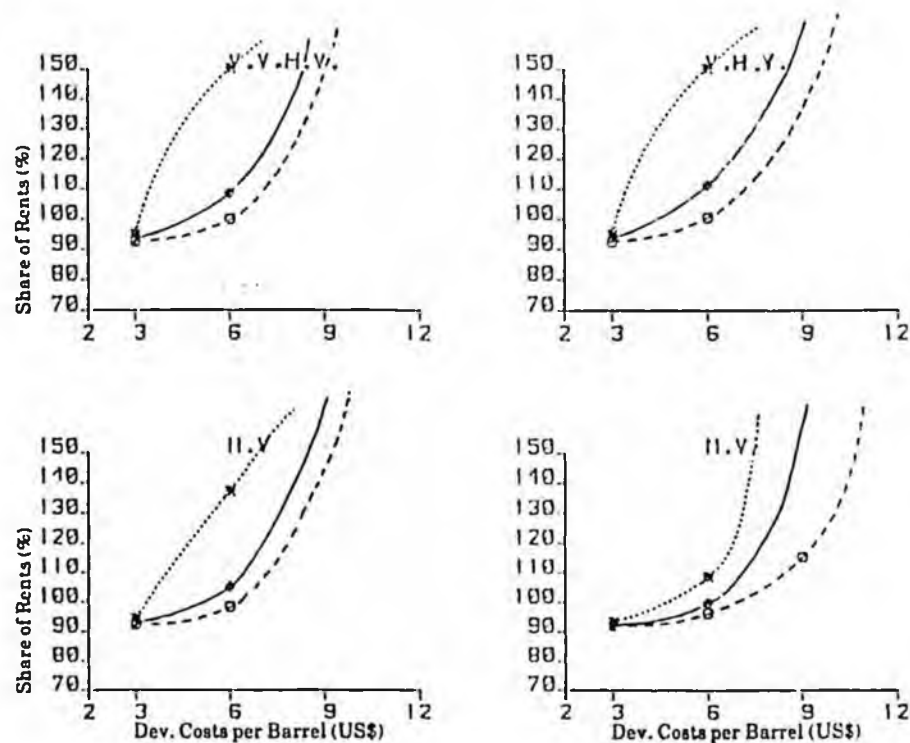


Figure 6.17
Norway (State Participation Included)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives



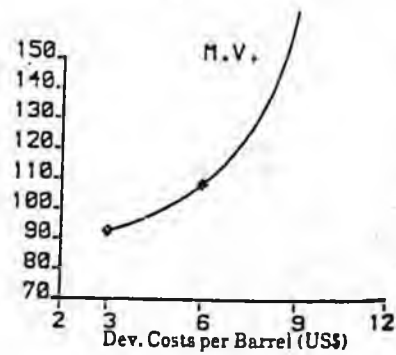
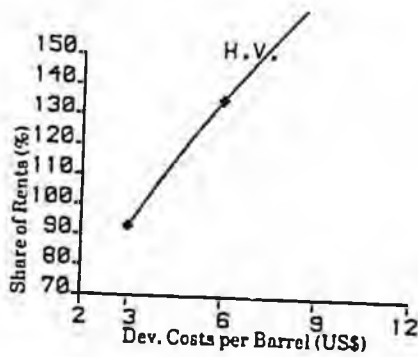
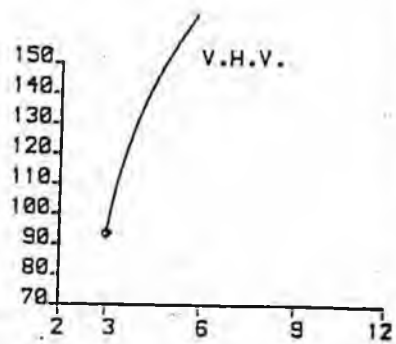
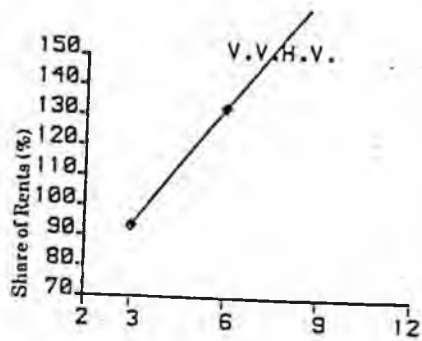
Legend:
 — Constant Real Oil Price (\$27)
 - - - Rising Price at 2% p.a. in Real Terms
 Falling Price at 2% p.a. in Real Terms

Figure 6.18
Norway (State Participation Included)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives



Legend:
 — Constant Real Oil Price (\$27)
 - - - Rising Price at 2% p.a. in Real Terms
 Falling Price at 2% p.a. in Real Terms

Figure 6.19
 Norway (State Participation Included)
 Government Share of Economic Rents, 10% Real Discount Rate
 Collapsed Real Oil Price



Chapter 55. Oil and Gas Properties Production Tax.

Section

- 11. Oil production tax
- 12. Adjustment in tax rates
- 13. Economic limit factor
- 16. Gas production tax
- 17. Relation to other taxes
- 20. Payment of tax
- 30. Filing of statements
- 40. Powers of Department of Revenue

Section

- 50. Incorrect returns
- 60. Delinquency
- 80. Collection and deposit of revenue
- 90. Refunds
- 110. Administration
- 135. Measurement
- 140. Definitions
- 150. Determination of gross value

Collateral references. — 71 Am. Jur. 2d, State and Local Taxation, §§ 218 — 220.

84 C.J.S., Taxation, §§ 404, 410.

State tax on or in respect of goods shipped in interstate commerce to consignee for sale on consignor's account without previous sale or order for purchase, 4 ALR2d 244.

Constitutional exemption from taxation as subject to legislative regulation respecting conditions of its assertion, 4 ALR2d 744.

Power of legislature to remit, release, or compromise tax claim, 28 ALR2d 1425.

When right to refund of state or local taxes accrues, within statute limiting time for applying for refund, 46 ALR2d 1350.

Legislative power to exempt from taxation property, purposes, or uses additional to those specified in constitution, 51 ALR2d 1031.

Financial hardship or inability to pay taxes as rendering inapplicable statutes denying remedy by injunction against assessment or collection of tax, 65 ALR2d 550.

Expenses and taxes deductible by lessee in computing lessor's oil and gas royalty or other return, 73 ALR2d 1056.

Sec. 43.55.010. Gross production tax. [Repealed, § 9 ch 136 SLA 1977.]

Sec. 43.55.011. Oil production tax. (a) There is levied upon the producer of oil a tax for all oil produced from each lease or property in the state, less any oil the ownership or right to which is exempt from taxation. The tax is equal to either the percentage-of-value amount calculated under (b) of this section or the cents-per-barrel amount calculated under (c) of this section, whichever is greater, multiplied by the economic limit factor determined for the oil production of the lease or property under AS 43.55.013. If the amounts calculated under (b) and (c) of this section are equal, the amount calculated under (b) of this section shall be treated as if it were the greater for purposes of this section.

(b) The percentage-of-value amount equals 12.25 percent of the gross value at the point of production of taxable oil produced on or before June 30, 1981, from the lease or property and 15 percent of the gross value at the point of production of taxable oil produced from the lease or property after June 30, 1981; except that for a lease or property coming into commercial oil production after June 30, 1981, the percentage-of-value amount equals 12.25 percent of the gross value at the point of production of taxable oil produced from the lease or prop-

erty in the first five years after the start of commercial oil production and equals 15 percent of the gross value at the point of production of taxable oil produced thereafter from the lease or property.

(c) The cents-per-barrel amount equals \$0.60 per barrel of taxable old crude oil produced from the lease or property, and \$0.80 per barrel for all other taxable oil produced from the lease or property, both as adjusted by AS 43.55.012.

(d) [Repealed, § 18 ch 116 SLA 1981.] (§ 1 ch 136 SLA 1977; am §§ 12, 18 ch 116 SLA 1981)

Cross references. — For oil and gas leasing provisions, see AS 38.05.180.

Effect of amendments. — The 1981 amendment added "on or before June 30, 1981" following "taxable oil produced" and added the language beginning "and 15

percent of the gross value" and ending "from the lease or property" in subsection (b). The amendment also repealed subsection (d) which provided for certain payments to the Alaska Native Fund in certain circumstances.

Sec. 43.55.012. Adjustment in tax rates. (a) [Repealed, § 18 ch 116 SLA 1981.]

(b) The cents-per-barrel amount set out in AS 43.55.011(c) as adjusted by (a) of this section applies to oil of 27 degrees API gravity. For each degree of API gravity less than 27 degrees the cents-per-barrel amount shall be reduced by \$.005 and for each degree of API gravity greater than 27 degrees the cents-per-barrel amount shall be increased by \$.005 except that oil above 40 degrees API gravity shall be taxed as 40 degree oil. In applying the gravity adjustment under this subsection, fractional degrees of API gravity shall be disregarded. (§ 1 ch 136 SLA 1977; am § 18 ch 116 SLA 1981)

Effect of amendments. — The 1981 amendment repealed the former subsection (a) which provided for a review of the prices received for crude oil or gas pro-

duced in Alaska and a report by the department to the governor concerning proposed changes.

Sec. 43.55.013. Economic limit factor. (a) [Repealed, § 18 ch 116 SLA 1981.]

(b)(1) The economic limit factor for oil production of a lease or property shall be computed according to the following formula:

$$(1 - \text{PEL}/\text{TP}) \exp ((460 \times \text{WD})/\text{PEL})$$

where: PEL = the monthly production rate at the economic limit;

TP = the 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; and

Where "exp" indicates that the expression following it is an exponent.

(2) If, for any month during the first 10 years following the commencement of commercial oil production of a lease or property the

economic limit factor for oil production of that lease or property computed under (1) of this subsection is 0.7 or less, then that factor shall be applied.

(3) If, for any month during the first 10 years following the commencement of commercial oil production of a lease or property, the economic limit factor for oil production of that lease or property computed under (1) of this subsection is greater than 0.7, then the economic limit factor is one.

(4) The economic limit factor for oil production of a lease or property after the first 10 years following the commencement of commercial oil production shall be computed and applied under (1) of this subsection.

(c) The economic limit factor for gas production of a lease or property equals one minus the ratio of the monthly production rate at the economic limit to the production during the month for which the tax is to be paid.

(d) The monthly production rate at the economic limit for a lease or property is presumed to be 300 barrels times the number of well days for the lease or property during the month for which the tax is to be paid. The taxpayer may rebut this presumption at a formal hearing under AS 43.05.240 by providing clear and convincing evidence of a different monthly production rate at the economic limit for the lease or property. The hearing shall be held before February 15 of the year or within six months after commencement of oil production for a lease or property. The monthly production rate at the economic limit for the lease or property based upon the clear and convincing evidence of the taxpayer shall be calculated by dividing the value determined under (f) of this section into the average monthly direct operating cost determined under (e) of this section and shall be used for purposes of this section for all oil production during that calendar year from the lease or property.

(e) The average monthly direct operating cost for oil production operations of the lease or property shall be determined based on a period of not less than four consecutive months. The direct operating costs include only royalty, production supplies, purchased fuel, routine maintenance, and wages and benefits of employees working on the production operations. Additional direct operating costs not listed in this section may be included only after their inclusion in a regulation adopted by the department. The direct operating costs do not include capital expenditures, tangible or intangible drilling expenses, costs of well workovers, costs for replacement or repairs (other than routine maintenance), depreciation or amortization, taxes, insurance, overhead, money paid or set aside (or booked as being paid or set aside) to cover the cost of terminating the oil production operations of the lease or property, or any other cost not directly related to the oil production operations of the lease or property.

(f) For the purpose of calculating the economic limit, the value at the point of production of oil produced from the lease or property shall be determined on the basis of the acquisition cost C.I.F. at West Coast refineries for imported oil of like quality, minus the reasonable cost of transportation between the point of production of the oil from the lease or property and those West Coast refineries.

(g) The monthly production at the economic limit for a lease or property is presumed to be 3,000 Mcf times the number of well days for the lease or property during that month for which the tax is to be paid. The taxpayer may rebut this presumption at a formal hearing under AS 43.05.240 by providing clear and convincing evidence of a different monthly production rate at the economic limit for the lease or property. The hearing shall be held before February 15 of the year or within six months after commencement of gas production for a lease or property. The monthly production rate at the economic limit for the lease or property based upon the clear and convincing evidence of the taxpayer shall be calculated by dividing the value determined under (i) of this section into the average monthly direct operating cost determined under (h) of this section.

(h) The average monthly direct operating cost for gas production operations of the lease or property shall be determined based on a period of not less than four consecutive months. The direct operating costs include only royalty actually and currently paid, production supplies, purchased fuel, routine maintenance, and wages and benefits of employees working on the production operations. Additional direct operating costs not listed in this section may be included only after their inclusion in a regulation adopted by the department. The direct operating costs do not include capital expenditures, tangible or intangible drilling expenses, costs of well workovers, costs for replacement or repairs (other than routine maintenance), depreciation or amortization, taxes, insurance, overhead, money paid or set aside (or booked as being paid or set aside) to cover the cost of terminating the gas production operations of the lease or property, or any other cost not directly related to the gas production operations of the lease or property.

(i) For the purpose of calculating the economic limit, the value at the point of production of gas produced from the lease or property shall be determined on the basis of the volume weighted average price paid for gas of like quality and pressure in the same field.

(j) The department may aggregate two or more leases or properties (or portions of them), for purposes of determining economic limit factors under this section and applying them to AS 43.55.011 or AS 43.55.016, when economically interdependent oil or gas production operations are not confined to a single lease or property. The department may also segregate a lease or property into two or more parts, for purposes of determining economic limit factors under this section.

applying them under AS 43.55.011 or AS 43.55.016, when two or more economically independent oil or gas production operations are being conducted on it, or when old crude oil is produced from the same lease or property as other oil.

(k) A determination of the monthly production rate at the economic limit for a lease or property is retroactive to January 1 of the current year. For production of a lease or property commencing after January 1, the determination of the monthly production rate at the economic limit for that lease or property made within six months after the commencement of production is retroactive to the commencement of production. (§ 1 ch 136 SLA 1977; am §§ 13 — 16, 18 ch 116 SLA 1981)

Effect of amendments. — The 1981 amendment rewrote subsection (b) and repealed former subsection (a) which read "The economic limit factor for old crude oil production of a lease or property equals 1 minus the ratio of the monthly production rate at the economic limit to the production during the month for which the tax is

to be paid." The amendment also rewrote subsection (g) and in subsection (h), added "actually and currently paid" following "only royalty" in the second sentence and substituted "volume weighted average" for "highest" preceding "price paid" in subsection (i).

Sec. 43.55.015. Tax per barrel of oil. [Repealed, § 9 ch 136 SLA 1977.]

Sec. 43.55.016. Gas production tax. (a) There is levied upon the producer of gas a tax for all gas produced from each lease or property in the state, less any gas the ownership or right to which is exempt from taxation. The tax is equal to either the percentage-of-value amount calculated under (b) of this section or the cents-per-Mcf amount calculated under (c) of this section, whichever is greater, multiplied by the economic limit factor determined for gas production of the lease or property under AS 43.55.013. If the amounts calculated under (b) and (c) of this section are equal, the amount calculated under (b) of this section shall be treated as if it were the greater for purposes of this section.

(b) The percentage-of-value amount equals 10 per cent of the gross value at the point of production of the taxable gas produced from the lease or property.

(c) The cents-per-Mcf amount equals \$.064 per thousand cubic feet of taxable gas produced from the lease or property as adjusted by AS 43.55.012. (§ 1 ch 136 SLA 1977)

Sec. 43.55.017. Relation to other taxes. (a) Except as provided in this chapter and in AS 43.58, the taxes imposed by this chapter are in place of all taxes now imposed by the state or any of its municipalities, and neither the state nor a municipality may impose a tax upon

(1) producing oil or gas leases;

(2) oil or gas produced or extracted in the state.

(3) the value of intangible drilling and exploration expenses.

(b) The taxes imposed by this chapter are in place of all taxes imposed by a municipality upon oil or gas in place or nonproducing oil or gas leases or properties.

(c) The taxes imposed by this chapter are not in place of the tax imposed by AS 43.57 or income taxes, franchise taxes or taxes upon the retail sale of oil or gas products. (§ 1 ch 136 SLA 1977)

NOTES TO DECISIONS

Cited in *Liberati v. Bristol Bay Borough*, Sup. Ct. Op. No. 1735 (File No. 3365), 584 P.2d 1115 (1978).

Sec. 43.55.018. Credit against tax. [Repealed, § 18 ch 116 SLA 1981.]

Sec. 43.55.020. Payment of tax. (a) The gross production tax on oil or gas shall be paid monthly. The tax is due on the 20th day of each calendar month on oil or gas produced from each lease or property during the preceding month. If the tax is not paid before the end of the month in which it becomes due, the tax becomes delinquent.

(b) The gross production tax on oil or gas shall be paid by or on behalf of the producer.

(c) *[Repealed, § 7 ch 101 SLA 1972.]*

(d) In making settlement with the royalty owner the producer may deduct the amount of the tax paid on royalty oil or gas, or may deduct royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid.

(e) Gas produced in excess of that needed for safety purposes, except gas used in the operation of a lease or property in drilling for or producing oil or gas, or for repressuring, is considered, for the purpose of this chapter and in the amount used, as gas produced from a lease or property. Gas flared beyond the amount authorized for safety by the Alaska Oil and Gas Conservation Commission under AS 31.05 is considered as gas produced, except that it is subject to a penalty equal to the tax computed under AS 43.55.016 as adjusted by AS 43.55.012 per thousand cubic feet of gas for the month in which the gas was flared.

(f) If oil or gas is sold under circumstances where the sale price does not represent the prevailing value for oil or gas of like kind, character or quality in the field or area from which the product is produced, the department may require the tax to be paid upon the basis of the value of oil or gas of the same kind, quality and character prevailing during the calendar month or production for that field or area. (§ 3 ch 7 ESLA 1955; am §§ 5 — 9 ch 101 SLA 1972; am § 7 ch 107 SLA 1976; am §§ 2, 3 ch 136 SLA 1977; am § 3 ch 158 SLA 1978)

Legislative history reports. — For report on ch. 101, SLA 1972 (FCCS HCSSB 168), see 1972 House Journal, p. 963. For report on ch. 107, SLA 1976 (SCS CSHB 583), see 1976 House Journal, p. 556.

Sec. 43.55.030. Filing of statements. (a) The tax shall be paid to the department and the person paying the tax shall file with the department at the time the tax is required to be paid a statement, under oath, on forms prescribed by or acceptable to the department, giving with other information required, the following:

(1) a description of the lease or property from which the oil or gas was produced, by name, legal description, lease number or by accounting code numbers assigned by the department;

(2) the names of the producer and the person paying the tax;

(3) the gross amount of oil or gas produced from the lease or property, and the percentage of the gross amount owned by each producer for whom the tax is paid;

(4) the total value of the oil or gas produced from the lease or property owned by each producer for whom the tax is paid; and

(5) the name of the first purchaser and the price received for the oil or gas if sold in the state.

(b) *[Repealed, § 11 ch 101 SLA 1972.]*

(c) *[Repealed, § 11 ch 101 SLA 1972.]*

(d) Reports by or on behalf of the producer are delinquent the first day following the day the tax is due. Each producer is subject to a penalty of \$25 a day for each lease or property upon which the report is not filed. The penalty for failure to file a report is in addition to the penalty for delinquent taxes, and is a lien against the assets of the producer. (§ 4 ch 7 ESLA 1955; am §§ 10 — 12 ch 101 SLA 1972; am §§ 4 — 6 ch 136 SLA 1977)

Revisor's notes. — Paragraph (a)(6) was renumbered as (a)(5) in 1983 since former (a)(5) had been repealed.

Sec. 43.55.040. Powers of Department of Revenue. The department may (1) require a person engaged in production and the agent or employee of the person, and the purchaser of oil or gas, or the owner of a royalty interest in oil or gas to furnish additional information that is considered by the department as necessary to compute the amount of the tax; (2) examine the books, records, and files of such a person; (3) conduct hearings and compel the attendance of witnesses and the production of books, records, and papers of any person; and (4) make an investigation or hold an inquiry that is considered necessary to a disclosure of the facts as to (A) the amount of production from any oil or gas location, or of a company or other producer of oil or gas, and (B) the rendition of the oil and gas for taxing purposes. (§ 5 ch 7 ESLA 1955)

Sec. 43.55.050. Incorrect returns. The department may determine whether or not a return required by this chapter to be filed with it is correct. If a person makes an untrue or incorrect return of the gross production or the value of it, or fails or refuses to make a return, the department shall, under regulations prescribed by it, determine the correct amount of gross production or the value of it, and compute the tax. (§ 6 ch 7 FSLA 1955)

Sec. 43.55.060. Delinquency. When the tax provided for in this chapter becomes delinquent, it bears interest at the rate prescribed in AS 43.05.225. If any person fails to make a report required by this chapter, within the time prescribed by law for the report, the department shall examine the books, records and files of the person to determine the amount and value of the production to compute the tax, and the department shall add to the tax the cost of the examination, together with any penalties accrued. (§ 7 ch 7 ESLA 1955; am § 4 ch 58 SLA 1971; am § 13 ch 82 SLA 1982)

Effect of amendments. — The 1982 amendment substituted "rate prescribed in AS 43.05.225" for "the rate of six percent a year" at the end of the first sentence.

Sec. 43.55.070. Lien for tax. [Repealed, § 4 ch 94 SLA 1976. For current law, see AS 43.10.035.]

Sec. 43.55.080. Collection and deposit of revenue. The department shall deposit in the general fund the money collected by it under this chapter. (§ 10 ch 7 ESLA 1955; am § 14 ch 101 SLA 1972)

Sec. 43.55.090. Refunds. In case of overpayment, duplicate payment or payment made in error, the department may issue a certificate stating the facts and the amount of the refund to which the taxpayer is entitled. Upon presentation of the certificate to the Department of Administration, the Department of Administration shall issue a warrant for the refund. The refund shall be paid out of the unappropriated gross production tax in the treasury. (§ 11 ch 7 ESLA 1955)

Sec. 43.55.100. Acceptance of deductions. [Repealed, § 15 ch 101 SLA 1972.]

Sec. 43.55.110. Administration. (a) The department may adopt regulations for the purpose of making and filing reports required by this chapter and otherwise necessary to the enforcement of this chapter.

(b) The department may require a sufficient bond from every person charged with the making and filing of reports and the payment of the tax. The bond shall run to the state and shall be conditioned upon the

the regulations of the department, and for the prompt payment, by the principal on the bond, of all taxes due the state by virtue of this chapter.

(c) If reports required have not been filed, or are insufficient to furnish the information required by the department, the department shall institute, in the name of the state upon relation of the department, the necessary action or proceedings to enjoin the person from continuing operations until the reports are filed.

(d) Upon showing that the state is in danger of losing its claims or the property is being mismanaged, dissipated or concealed, a receiver shall be appointed at the suit of the state. (§ 13 ch 7 ESLA 1955)

Sec. 43.55.120 — 43.55.130. Noncompliance and false reports. [Repealed, § 46 ch 113 SLA 1980. For criminal penalties, see AS 43.05.290.]

Sec. 43.55.135. Measurement. For the purposes of this chapter, oil shall be measured in terms of a "barrel of oil" and gas shall be measured in terms of a "cubic foot of gas." (§ 16 ch 101 SLA 1972)

Sec. 43.55.140. Definitions. In this chapter

(1) "API gravity" means the specific gravity of oil measured in degrees on the American Petroleum Institute scale;

(2) "barrel of oil" means 42 United States gallons of oil of 231 cubic inches a gallon computed at a temperature of 60 degrees Fahrenheit;

(3) "cubic foot of gas" means the volume of gas contained in one cubic foot of space measured at a pressure base of 14.65 pounds per square inch absolute and a temperature base of 60 degrees Fahrenheit;

(4) "department" means the Department of Revenue;

(5) "gas" means all natural, associated or casinghead gas, all hydrocarbons produced at the wellhead not defined as oil, and all liquid hydrocarbons extracted at a gas processing plant;

(6) "gross value at the point of production" means

(A) for oil, the value of the oil at the point where it is metered or measured (by automatic custody transfer meter, tank gauge, or other method approved by the commissioner) in a condition of pipeline quality on the premises of the lease or property from which it is recovered; however, if the oil is not of pipeline quality when it is removed from the premises of the lease or property from which it is recovered, or if the oil recovered from a lease or property is not metered or measured (by automatic custody transfer meter, tank gauge, or other method approved by the commissioner) on the premises of the lease or property from which it is recovered, then the gross value at the point of production is the value of that oil at the off-premises location where the oil is first metered or measured (by automatic custody transfer meter, tank gauge, or other method approved by the commissioner) in a condition of pipeline quality;

(B) for gas recovered from or in association with oil, the value of the gas at the point where it is accurately metered or measured after separation from the oil; for gas run through a gas processing plant, the gross value at the point of production is the full consideration received by the producer for the gas if sold in an arm's length transaction or, in the absence of an arm's length transaction, is the sum of the value of the liquids extracted from the gas at the plant and the value of the residue gas, less a reasonable allowance for processing the gas at the plant and for transporting the gas to the plant from the premises upon which the oil production operation is conducted; and

(C) for gas not recovered from or in association with oil, the value of the gas at the point where it is accurately metered or measured or the value of the gas at the point of sale, if any, on the premises of the lease or property from which the gas is recovered, whichever is the higher value; for gas run through a gas processing plant, the gross value at the point of production is the full consideration received by the producer for the gas if sold in an arm's length transaction or, in the absence of an arm's length transaction, is the sum of the value of the liquids extracted from the gas at the plant and the value of the residue gas, less a reasonable allowance for processing the gas at the plant and for transporting the gas to the plant from the point where it was accurately metered or measured;

(7) "intangible drilling expenses" as defined in 26 U.S.C. 263(c) (Internal Revenue Code) as defined on January 1, 1974;

(8) "lease or property" means any right, title or interest in or the right to produce or recover oil or gas including:

(A) a mineral interest,

(B) a leasehold interest,

(C) a working interest, royalty interest, overriding royalty interest, production payment, net profit interest or any other interest in a lease, concession, joint venture or other agreement for oil and gas exploration, development or production,

(D) a working interest, royalty interest, overriding royalty interest, production payment, net profit interest or any other interest in an agreement for unitization or pooling under the provisions of 26 U.S.C. 614(b)(3) (Internal Revenue Code) as defined on January 1, 1974;

(9) "oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced at the wellhead in liquid form and the liquid hydrocarbons known as distillate or condensate recovered by separation from gas other than at a gas processing plant;

(10) "oil production operation" means the operation by which oil is recovered from a lease or property and rendered into oil of pipeline quality, and includes any gathering done before the oil is finally rendered into oil of pipeline quality;

(11) "old crude oil" means crude oil production classified as "old crude oil" in 10 CFR Chapter II Part 212-72 on May 1, 1977, and which

(12) "ownership or right to which is exempt from taxation" means any ownership interest of the federal government or the state;

(13) "pipeline quality" means good and merchantable condition;

(14) "well days" means the number of days in which a well is operating during a month. (§ 1 ch 7 ESLA 1955; am § 17 ch 101 SLA 1972; am § 3 ch 4 FSSLA 1973; am § 4 ch 159 SLA 1975; am §§ 7, 9 ch 136 SLA 1977)

Revisor's notes. — The paragraphs were renumbered in 1983 to achieve alphabetical order and to delete repealed paragraphs.

Sec. 43.55.150. Determination of gross value. (a) For the purposes of this chapter, the gross value shall be calculated using the reasonable costs of transportation of the oil or gas. The reasonable costs of transportation shall be the actual costs, except

(1) when the parties to the transportation of oil or gas are affiliated;

(2) when the contract for the transportation of oil or gas is not an arm's length transaction or is not representative of the market value of that transportation;

(3) when the method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation.

(b) If the department finds that the conditions in (a)(1), (2), and (3) of this section are present, the department shall determine the reasonable costs of transportation, using the fair market value of like transportation, the fair market value of equally efficient and available alternative modes of transportation, or other reasonable methods. Transportation costs fixed by tariff rates properly on file with the Alaska Public Utilities Commission or other regulatory agency shall be considered prima facie reasonable. (§ 6 ch 107 SLA 1976; am § 92 ch 59 SLA 1982)

Effect of amendments. — The 1982 amendment substituted "Alaska Public Utilities Commission" for "Alaska Pipeline Commission" near the end of subsection (b).

Chapter 56. Oil and Gas Exploration, Production and Pipeline Transportation Property Taxes.

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- 20. Exemptions
- 30. In place of other taxes
- 40. State Assessment Review Board
- 50. Per diem and expenses
- 60. Assessment
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- 80. Investigation
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- 110. Appeal to the department
- 120. Appeal to the State Assessment Review Board
- 130. Hearings of State Assessment Review Board
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- 180. Remedy

**CHAPTER 55.
OIL AND GAS PROPERTIES
PRODUCTION TAX**

The provisions of AS 43.50.225 relating to the interest on delinquent taxes apply to the tax imposed under this chapter. (Eff. 2/27/83, Reg. 85)

Authority: AS 43.05.080 AS 43.50.100(d)
AS 43.05.220(a) AS 43.50.150
AS 43.05.225

15 AAC 50.190. DEFINITIONS. In addition to the definitions contained in AS 43.50.170, in this chapter

(1) "cigarette business" means a category of activity in the state as a manufacturer, distributor, direct-buying retailer, vending machine operator, retailer, or buyer of cigarettes;

(2) "department" means the Department of Revenue;

(3) "import or acquire" includes all manners, ways, and modes of bringing or obtaining cigarettes in the state and, in the case of a manufacturer, includes bringing cigarettes into the state for samples or storage;

(4) "Indian" means a person registered on the tribal rolls of the Indian tribe occupying an Indian reservation;

(5) "Indian reservation" means all land set aside by the United States for the exclusive use and occupancy of Indian tribes, which are recognized as Indian reservations under federal law and, as of February 27, 1983, includes only the Annette Islands Reserve set aside by the United States for the exclusive use and occupancy of Metlakatla Indian Community; and

(6) "license year" means the 12 months commencing July 1 of one calendar year and ending June 30 of the following calendar year. (Eff. 2/27/83, Reg. 85)

Authority: AS 43.05.080
AS 43.50.150
AS 43.50.170

Section

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15 AAC 55.010. MONTHLY PRODUCTION RATE AT THE ECONOMIC LIMIT. (a) The presumed monthly production rate at the economic limit of 300 barrels per well day for oil production of a lease or property includes royalty and all other ownership interests in that production.

(b) When the monthly production rate at the economic limit is being determined for a lease or property by dividing the per-unit value of production into the average monthly direct operating costs, the monthly production rate at the

economic limit equals the final quotient obtained by dividing, first, the per-unit value of production into the average monthly direct operating costs other than royalty, and then dividing the first quotient by the fraction of production corresponding to all nonroyalty interests in the lease or property. If some or all of a direct operating cost is borne by a royalty interest, then with respect to that cost the royalty interest will be regarded as a nonroyalty interest for purposes of the preceding sentence.

(c) The tax on oil produced from a lease or property in commercial production after June 30, 1981, must be computed by using the rates specified in AS 43.55.011 (b) and the economic limit factor specified in AS 43.55.013 (b). "Commercial production," for purposes of this subsection, means the production of oil for purposes of sale, or other beneficial use not associated with the exploration and development of the field in which the lease or property lies, except when the sale or beneficial use is incidental to the testing of an unproved well or unproved completion interval.

(d) When the primary production from a well or wells on a lease or property is gas, the monthly production at the economic limit for that lease or property is presumed to be 3,000 Mcf per well times the number of well days for that lease or property during that month for which the tax is to be paid. The economic limit for gas production of a lease or property includes royalty and all other ownership interests in the production. The taxpayer may rebut this presumption at a formal hearing under AS 43.05.240 by providing clear and convincing evidence that the value determined under AS 43.55.013(i) for the lease or property, when divided into the average monthly direct operating cost determined under AS 43.55.013(h) for the lease or property, produces a different amount for the monthly production at the economic limit under AS 43.55.013(g) for the lease or property. (Eff. 7/1/77, Reg. 63; am 3/26/82, Reg. 81)

Authority: AS 43.05.080 AS 43.55.013
AS 43.55.011 AS 43.55.110

15 AAC 55.020. WELL DAYS. The number of well days for a well during a month is the number of days the well is reported to the Division of Oil and Gas Conservation as having

been produced during that month. The days of operation for injection wells will not be included in the determination of well days. (Eff. 7/1/77, Reg. 63)

Authority: AS 43.05.080
AS 43.55.110
AS 43.55.140

15 AAC 55.030. ECONOMIC LIMIT FACTOR FOR CASINGHEAD GAS. When the primary production from a well or wells on a lease or property is oil, the economic limit factor for gas produced from or in association with that oil will be calculated using the following formula:

economic limit factor = $1 - (PEL/TP)$

where: PEL = the monthly production rate at the economic limit, presumed to be 300 barrels per well times the total number of well days in the month for which the tax is to be paid;

TP = the total oil production during the month for which the tax is to be paid.

(Eff. 7/1/77, Reg. 63; am 11/25/77, Reg. 64; am 3/26/82, Reg. 81)

Authority: AS 43.05.080
AS 43.55.013
AS 43.55.110

15 AAC 55.040. INTERIM TAXATION OF GAS WELL GAS. For gas produced on or after July 1, 1977, and before January 1, 1978, which is not produced from or in association with oil, payments must be made using an economic limit factor of one (1.000000). When an economic limit factor is determined for production during 1978 as required by AS 43.55.013(g), the taxpayer may apply that economic limit factor to the gas produced on or after July 1, 1977, and before January 1, 1978, and the tax paid for that gas production will be adjusted accordingly. (Eff. 7/1/77, Reg. 63)

Authority: AS 43.05.080 AS 43.55.016
AS 43.55.013 AS 43.55.110

15 AAC 55.045. ECONOMIC LIMIT FACTOR FOR DISTILLATE OR CONDENSATE. When the primary production of a well or wells on a lease or property is gas, the economic limit

factor for distillate or condensate recovered from that gas will be calculated using the following formula:

$$\text{economic limit factor} = [1 - (\text{PEL}/\text{TP})] \exp [(4.600 \times \text{WD})/\text{PEL}]$$

where: PEL = the monthly production rate at the economic limit, presumed to be 3,000 Mcf per well times the total number of well days in the month for which the tax is to be paid;

TP = the total gas 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; and

where "exp" means that the expression following it is an exponent. (Eff. 3/26/82, Reg. 81)

Authority: AS 43.05.080
AS 43.55.013
AS 43.55.110

15 AAC 55.050. GAS RUN THROUGH A GAS PROCESSING PLANT. For gas run through a gas processing plant, the comparison of the cents-per-Mcf amount under AS 43.55.016(c) and the percentage-of-value amount under AS 43.55.016(b) will not be made by comparing cents-per-Mcf to percentage-of-value for the residue gas separately from the extracted liquids. The percentage-of-value amount is to be based on the full consideration received by the producer for that gas in an arm's length transaction, or, in the absence of an arm's length transaction, the sum of the value of the liquids extracted from the gas at the plant and the value of the residue gas less a reasonable allowance for processing the gas at the plant and for transporting the gas to the plant. The cents-per-Mcf amount is to be based on the volume of gas delivered to the gas processing plant, minus the sum of (1) the volume of gas returned from the processing plant and used in the operation of the lease or property in drilling for or producing oil or gas, (2) the volume of gas returned from the processing plant and injected back into the reservoir for repressuring, and (3) that

percentage of the gas used as fuel for the processing plant which equals the percentage of the gas delivered to the processing plant which is returned and used for either of the purposes described in (1) or (2) of this sentence. (Eff. 7/1/77, Reg. 63; am 11/25/77, Reg. 64)

Authority: AS 43.05.080 AS 43.55.110
AS 43.55.016 AS 43.55.140

15 AAC 55.060. LEASE IDENTIFICATION NUMBER. The Department of Revenue may require the person paying the tax to include an identification number on the statement filed. (Eff. 1/2/71, Reg. 36)

Authority: AS 43.55.130

15 AAC 55.070. FLARED GAS PENALTY. The cents-per-Mcf penalty under AS 43.55.020(e) for gas flared beyond the amount authorized for safety by the Department of Natural Resources under AS 31.05.170(11)(H) is in addition to the tax imposed under AS 43.55.016. The volumes flared in excess of the amounts authorized for safety purposes will be determined on the basis of the total amount so authorized for the various facilities comprising a single integrated operation. (Eff. 7/1/77, Reg. 63)

Authority: AS 43.05.080 AS 43.55.020
AS 43.55.016 AS 43.55.110

15 AAC 55.080. INTEREST. If for any reason it is determined that returns made and taxes paid for production during a month were incorrect and a greater tax was due for that production, interest on the amount of the additional tax due for that production will be calculated and collected at the rate of six percent a year for the time between the last day of the month after the month of production and the day the additional tax for that production is paid. (Eff. 7/1/77, Reg. 63)

Authority: AS 43.05.080
AS 43.55.060
AS 43.55.110

15 AAC 55.090. SIGNIFICANT DIGITS IN ECONOMIC LIMIT FACTORS. All economic limit factors are to be calculated to not less than six decimal places. In rounding to the sixth decimal place, rounding may be down if that which is rounded out is less than 0.0000005, but it is to be up if that which is rounded out is greater than 0.0000005; if that which is rounded

out is exactly 0.0000005, the rounding is to be up or down so that the number in the sixth decimal place is even. (Eff. 7/1/77, Reg. 63; am 11/25/77, Reg. 64)

Authority: AS 43.05.080
AS 43.55.110

15 AAC 55.100. AVERAGE API GRAVITY. The API gravity of oil produced from a lease or property will be calculated each month using the weighted average of the API gravities of the oil produced during that month from the lease or property. (Eff. 3/7/74, Reg. 49; am 6/28/74, Reg. 50; am 7/1/77, Reg. 63)

Authority: AS 43.05.080
AS 43.55.012
AS 43.55.110

15 AAC 55.110. APPLICATION OF EARLY DEVELOPMENT INCENTIVE CREDIT AGAINST PRODUCTION TAX. (a) Against the

production tax each month on the oil or gas production of a lease or property, the EDIC for that lease or property as of the date of payment will be allowed as a credit, up to a maximum of 50 percent of that month's production tax on the oil or gas production of that lease or property.

(b) No EDIC for a lease or property will be allowed as a credit against interest on any delinquent production tax for that lease or property, as provided by AS 43.55.060, nor against any other penalty or fee that may be added to the production tax for that lease or property.

(c) No EDIC for a lease or property will be recognized in any adjustment in a production tax payment for that lease or property if that payment was originally made when the EDIC for that lease or property was zero.

(d) An adjustment to correct a production tax underpayment for a lease or property that was originally made when the EDIC for that lease or property was not zero will be attributed to EDIC for that lease or property, up to a maximum equal to the smallest of (1) the EDIC for that lease or property as of the date of the adjustment, (2) 50 percent of the adjustment, and (3) as much of the adjustment as possible without using in the total payment, as adjusted, more EDIC for that lease or property than there

was as of the date the payment was originally made; but no EDIC will be recognized in an adjustment to correct a production tax overpayment for a lease or property that was originally made when the EDIC for that lease or property was not zero.

(e) The EDIC for a lease or property will not

be allowed as a credit against production tax on oil or gas production of another lease or property, unless they are unitized or are treated, with the approval of the director as required by 15 AAC 58.070, as a single property for both reserves tax and production tax purposes. If part or all of more than one lease or property is unitized, or if two or more leases or properties are treated as a single property for both reserves tax and production tax purposes, then the EDIC attributable to each, or to the unitized portions of each, may be aggregated to determine an EDIC for the entire unit; however, if an adjustment is made after unitization (or after the several leases or properties are treated as a single property) for a production tax payment made for a lease or property before unitization (or before the several leases or properties were treated as a single property), then reference will be made only to the separate, unaggregated EDIC of that lease or property for purposes of applying (c) and (d) of this section.

(f) No EDIC for a lease or property will be allowed as a credit against the tax levied by AS 43.57.010.

(g) To illustrate the application of EDIC against production tax, the following examples are offered (and reference is also made to the examples appearing in 15 AAC 58.120 and 15 AAC 58.140):

EXAMPLE 1

On May 31 the cumulative total of reserves tax payments made before that date for a lease is \$1,000,000, while the cumulative total of EDIC allowed against production tax for that lease is \$950,000. The EDIC as of May 31 for that lease is thus \$50,000. The production tax on oil and gas production of that lease during April is due May 31 and is \$90,000. The EDIC is greater than 50 percent of the production tax to be paid, so the credit allowed is limited to 50 percent of the payment. Payment of \$45,000 is made that day and \$45,000 of EDIC is allowed against the production tax that is due. The EDIC on June 1 is \$5,000.

EXAMPLE 2

The initial facts are the same as for Example 1, except that this time the production tax on April production is \$105,000. Now the \$50,000 EDIC is not greater than 50 percent of the

payment, so the entire EDIC is allowed against that payment, reducing it to \$55,000. This latter sum is paid on May 31, and on June 1 the EDIC is zero.

EXAMPLE 3

Assume the same situation as in Example 2; the EDIC for the lease as of June 1 is zero. On June 30 production tax of \$100,000 is due for oil and gas production during May, while a reserves tax payment of \$900,000 is also due that day. Production tax payments that may be credited against the reserves tax total \$890,000, so a money payment of \$10,000 is made that day. As of July 1 the EDIC is \$10,000 but as of June 30 it is still zero. The taxpayer miscalculates the production tax and makes a money payment of \$95,000, thinking it to be full payment. On July 2 he discovers his mistake and adjusts the payment by paying the remaining \$5,000. No EDIC is recognized in this adjustment, even though the EDIC is \$10,000 as of July 2, because the payment being adjusted was made June 30 when the EDIC was still zero. This would still be the result if the taxpayer had overpaid the production tax by \$5,000 on June 30.

EXAMPLE 4

The initial facts are the same as for Example 3, except that this time the \$10,000 money payment for the reserves tax is made June 29. Now, on June 30 when the production tax payment is due, the EDIC is not zero, but \$10,000. The taxpayer again miscalculates the production tax as being \$95,000. The EDIC is less than 50 percent of this figure, so he applies the full \$10,000 as a credit and makes a money payment of \$85,000. On July 20 he discovers his mistake and makes the \$5,000 adjustment. This adjustment is attributable to EDIC to the extent of the smallest of (1) the EDIC as of July 20 (in this case, zero), (2) 50 percent of the adjustment (\$2,500), and (3) as much of the adjustment as possible without using more EDIC in the total payment, as adjusted, than there was as of the date (June 30) the original payment was made. In this case, the full \$10,000 EDIC was used June 30 in making the original payment, and accordingly, to allow any more EDIC in the \$5,000 adjustment would use more EDIC in the total payment, as adjusted, than there was when the original payment was made. Thus, both the first and third criteria are zero,

and accordingly, no EDIC can be allowed in the adjustment. The taxpayer makes a money payment of the full \$5,000.

EXAMPLE 5

On July 1 the EDIC for Blackacre is \$300,000 and the EDIC for Whiteacre is \$200,000. On July 31 production tax payments of \$50,000 for June production are made for each property. Half of each payment is made by using EDIC for the respective properties, so that as of August 1 the EDIC for Blackacre and Whiteacre is \$275,000 and \$175,000, respectively. Effective August 15, all of Blackacre and Whiteacre are unitized; no other leases or properties are involved. Beginning August 15, then, the unit may be regarded as a single property having an EDIC of \$450,000. On August 30 an adjustment is made to correct a \$5,000 underpayment of production tax on the June production of Blackacre. To apportion this adjustment between money payment and EDIC, one must refer to Blackacre's separate EDIC. The adjustment is attributable to EDIC to the extent of the smallest of (1) the EDIC as of August 30 in this case, \$275,000, (2) 50 percent of the adjustment (here, \$2,500), and (3) as much of the adjustment as possible without using more EDIC in the total payment, as adjusted, than there was on July 31 when the payment being corrected was made. In the original payment, \$25,000 of EDIC was used, which, coupled with the full \$5,000 of the adjustment, is less than the \$300,000 EDIC as of July 31. Thus, under the third criterion, \$5,000 of the adjustment could be attributed to EDIC. The smallest of the three criteria is therefore the second, and so \$2,500 of the adjustment made on August 30 is accounted for by EDIC for Blackacre, and the remaining \$2,500 is paid by the taxpayer. The application of Blackacre's separate EDIC in that adjustment reduces the EDIC for Blackacre to \$272,500. The EDIC for Whiteacre remains \$175,000, and the EDIC for purposes of the unit is \$447,500.

(h) All words and phrases used in this section that are defined in 15 AAC 58.150 - 15 AAC 58.180 have the same meanings for purposes of this section as they are given by those definitions. (Eff. 12/24/75, Reg. 56)

Authority: AS 43.05.080
AS 43.55.018

AS 43.55.060
AS 43.55.010
AS 43.58.160

15 AAC 55.120. PAYMENT AND REPORTING PROCEDURES. Repealed 9/15/82.

15 AAC 55.150. VALUATION OF OIL OR GAS. (a) Except as provided in 15 AAC 55.050, this section applies to all oil and gas produced in the state on a property or lease, whether or not the oil or gas is removed from the property or lease, less any oil or gas the ownership or right to which is exempt from state taxation.

(b) The gross value at the point of production for a producer's oil or gas equals the sales price under 15 AAC 55.160 for that oil or gas, less the producer's reasonable costs of transportation under 15 AAC 55.180 and 15 AAC 55.190 for that oil or gas from its point of production to its sales delivery point and less the producer's reasonable costs incurred downstream of the point of production for processing, conditioning and preparing gas and gas plant liquids for sale; unless

(1) subsection (c) of this section applies, in which case the gross value at the point of production for that oil or gas equals the prevailing value under 15 AAC 55.170 or 15 AAC 55.172 less the reasonable costs of transportation under 15 AAC 55.180 and 15 AAC 55.190 for that oil or gas from its point of production to its sales delivery point (or, if different, to the point where prevailing value is calculated under 15 AAC 55.170 or 15 AAC 55.172) and also less the producer's reasonable costs incurred downstream of the point of production for processing, conditioning and preparing gas and gas plant liquids for sale; or

(2) the gross value at the point of production for the producer's oil or gas would exceed the applicable maximum lawful price (if any) set by the U.S. Department of Energy, the Federal Energy Regulatory Commission, another governmental agency or a court of law (adjusted for any changes in value due to any processing, conditioning and transportation of that oil or gas occurring between its point of production and the point at which the applicable maximum lawful price is effective), in which case the gross value at the point of production equals that applicable maximum lawful price as adjusted for these changes in value.

(c) The prevailing value under 15 AAC 55.170 or 15 AAC 55.172 must be used in determining the gross value at the point of production for a producer's oil or gas if

(1) the circumstances relating to the disposition of the producer's oil or gas show fraud or an intent to evade taxes; or

(2) the sales price for that oil or gas is substantially lower (determined by analyzing the cash value of the consideration received for that oil or gas and taking into account the degree of difference between the prevailing value and the sales price for that oil or gas, the quantity of oil or gas involved in the transaction, and the duration of the transaction) than the prevailing value under 15 AAC 170 or 15 AAC 55.172 for oil or gas and one or more of the following conditions exist:

(A) the contract under which the producer's oil or gas is sold or exchanged is executed or renegotiated after December 31, 1979 and either sets a price for that oil or gas without adjustments tied to market conditions or does not provide for later renegotiation of prices at market rates;

(B) the contract sets a price which does not reasonably reflect market conditions for production from that field or area prevailing at the time the contract is executed or renegotiated; or

(C) the contract price under which the producer's oil or gas is sold or exchanged reflects an unusually weak bargaining position on the producer's part because of circumstances which the producer could reasonably have foreseen and taken steps to ameliorate or avoid.

(d) For valuation purposes, production of oil or gas does not include oil or gas

(1) used or unavoidably lost in production operations on the lease or property; or

(2) flared in amounts authorized for safety by the Alaska Oil and Gas Conservation Commission under AS 31.05.170(11)(H); or

(3) injected into a reservoir in the course of operations in the same field for purposes of repressuring or conservation.

(e) In this section, 15 AAC 55.160, and 15 AAC 55.210, the terms "exchange" and "exchanged" do not include a transfer of oil by a producer to a third party at the Port of Valdez or at another port in the state for purposes of operational necessity or convenience in what otherwise would be a bona fide, arm's-length exchange but for the fact that at the time of the particular transfer the producer expects to later receive a like amount of similar quality oil from that third party at the same port. This transfer to a third party and the later transfer from the third party will be disregarded and the oil transferred will be treated as if it had remained in the possession of the transferring producer pending final disposition of the oil. (Eff. 1/6/80, Reg. 73; am 5/21/81, Reg. 78)

Authority: AS 43.05.080

AS 43.55.020(e) and (f)

AS 43.55.110

AS 43.55.150

15 AAC 55.160. SALES PRICE. (a) The sales price for purposes of 15 AAC 55.010 — 15 AAC 55.210 for first sales of a producer's oil or gas to one or more third parties is the cash value of the full consideration being given in receipt for the oil or gas in those sales.

(b) If a producer's oil or gas is sold to an affiliate of that producer (as opposed to being transferred from one division to another within the same corporate person), the sales price of that oil or gas for purposes of 15 AAC 55.010 — 15 AAC 55.210 is the greater of

(1) the cash value of the full consideration given in receipt for the oil or gas so sold; and

(2) the price attributable to that sale which is entered on the producer's books in accordance with generally accepted accounting principles consistently applied.

(c) If a producer's oil or gas is retained by the producer or is transferred from the production division to another division within the same corporate person, the sales price of that oil or gas for purposes of 15 AAC 55.010 — 15 AAC 55.210 is the price attributable to that oil or gas which is entered on the producer's books in accordance

generally accepted accounting principles, consistently applied.

(d) If a producer exchanges oil or gas with a third party, the sales price of that oil or gas for purposes of 15 AAC 55.010 — 15 AAC 55.210 is

(1) the price prescribed in the exchange agreement for the producer's oil or gas for purposes of settling accounts and cashing out any net exchange balances in the producer's favor (to illustrate what is meant by a net exchange balance in the producer's favor, suppose the exchange is for oil on a barrel-for-barrel basis and the producer's volume to the third party exceeds the volume received from the third party; the amount of that excess would be the net exchange balance in the producer's favor); or

(2) if there is no such price prescribed in the exchange agreement, the price attributable to the oil or gas received by the producer which is entered on the producer's books in accordance with generally accepted accounting principles, consistently applied. (Eff. 1/6/80, Reg. 73)

Authority: AS 43.05.080

AS 43.55.020(f)

AS 43.55.110

15 AAC 55.165. ESTIMATED PAYMENT OF TAXES. (a) Beginning with the six-month period of July through December 1984, and for each succeeding six-month period after that, the department will compute and publish an interim sales price for oil from each oil producing field or area in Alaska for each month of that six-month period. The department will publish interim sales prices for the first six months of a calendar year before August 31 of that year and will publish interim sales prices for the second six months of the calendar year before March 1 of the following year. The interim sales price will be based on the volume-weighted average sales price of all taxpayers' sales in the same market for each month as reported by the taxpayers on their production tax returns. The volume-weighted average reported sales price is an arithmetic calculation based on returns as filed and is not a determination of the prevailing value of the oil.

(b) A taxpayer will recalculate its aggregate tax liability based on the interim sales price under (a) this section and it shall pay the difference

between the reported tax liability and the recalculated tax liability for the six-month period. If the amount of taxes paid by a taxpayer exceeds the recalculated tax liability for the six-month period, then the taxpayer may treat the excess as a credit against future estimated payments. Notwithstanding 15 AAC 05.050, the department will defer action on a claim for refund of the recalculated tax until the department has made a final determination of taxes due under 15 AAC 55.

(c) A taxpayer shall file a report on a form prescribed by the department and shall, as appropriate, either pay with money or by applying a credit accrued under (b) of this section, or claim a credit for, the difference between the recalculated tax liability under this section and the reported tax liability. The report and the payment of claim of credit for the first six months of the calendar year must be filed no later than October 31 of that year, and the report and the payment or claim of credit for the second six months of the calendar year must be filed no later than April 30 of the following year. (Eff. 9/1/84, Reg. 91)

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

15 AAC 55.170 PREVAILING VALUE FOR OIL. (a) For a producer's oil, the prevailing value for purposes of this chapter is the arithmetic average acquisition cost C.I.F. (at the refinery inlet in the same market in which the producer's Alaskan oil is refined) based on the sales price of like oil sold in up to three third-party, arm's-length transactions selected by the department. In this subsection, "like oil" means an oil of substantially similar quality produced in the same general area of the state and subject to the same federal price controls, if any, as the oil for which the prevailing value is to be determined.

(b) If the information under (a) of this section is not available, then the prevailing value for purposes of this chapter equals the arithmetic average acquisition cost C.I.F. (at the refinery inlet in the same market in which the producer's Alaskan oil is refined) of up to six oils selected by the department including

(1) up to three domestic oils of substantially similar quality which are sold in significant

quantities in the same market or near the same market; and

(2) up to three imported oils of substantially similar quality which are sold in significant quantities in the same market or near the same market.

(c) The respective acquisition cost C.I.F. at the refinery inlet in a market for each of the oils used in this section equals the sum of

(1) the respective official government sales price or posted price of the oil (with adjustments for differentials and surcharges) appearing in the latest Platt's Oilgram Price Report published on or before the last day of a month; plus

(2) the respective tanker transportation cost of the oil from its port of origin to ship's rail in the same market as that in which the producer's Alaskan oil is refined, to be calculated

(A) by multiplying the London Tanker Broker's average freight rate assessment ("AFRA") applicable to that voyage during that month for AFRA LR 2 (Long Range 2) oil tankers, by the most recently published Worldscale rate for that voyage; or

(B) by applying another applicable freight rate if foreign flag vessels are prohibited from transporting that oil; plus

(3) any canal tolls and expenses not included in the applicable freight rate for that voyage; plus

(4) pipeline or other carrying charges. (Eff. 1/6/80, Reg. 73; am 5/21/81, Reg. 78; am 9/1/84, Reg. 91)

Authority: AS 43.05.080
AS 43.55.020(f)
AS 43.55.110

15 AAC 55.172 PREVAILING VALUE FOR GAS. For a producer's gas, the prevailing value for purposes of this chapter is

(1) the volume-weighted average of the prices received under the terms of sales contracts for significant quantities which have been entered into or the pricing provisions of which have been amended during the tax year or the two preceding years at the sales delivery points within the

same market for that production by the producer; in arm's-length sales transactions for like kind character, and quality Alaskan gas produced during the month; or

(2) if the producer makes no arm's-length sales of significant quantities at the sales delivery points within the same market for like kind character, and quality Alaskan gas produced during the month, the volume-weighted average of the prices under the terms of arm's-length sales contracts for significant quantities of gas (whether between third parties or not) which were entered into or the pricing provisions of which were amended during the tax year or the two preceding years from the same field as the producer's gas (or if there are no contracts which comply with this paragraph for that field, contracts which comply with this paragraph in the nearest field to that field), with appropriate adjustments for differences, if any, in kind, character, and quality between gas sold under the reference sales contracts and the producer's gas. (Eff. 5/21/81, Reg. 78)

Authority: AS 43.05.080
AS 43.55.020(f)
AS 43.55.110

15 AAC 55.180. CHOICE OF METHODS FOR DETERMINING REASONABLE COST OF TRANSPORTATION. (a) Except as provided in (b) of this section, the reasonable cost of transportation is the actual cost of transportation as determined in 15 AAC 55.190(a) and (b).

(b) The reasonable cost of transportation is the fair market value as defined in 15 AAC 55.190(c) when all of the following conditions exist:

(1) the parties to the transportation of oil or gas are affiliated;

(2) the contract for the transportation of oil or gas is not an arm's-length transaction or is not representative of the market value of the transportation; and

(3) the method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation. (Eff. 1/6/80, Reg. 73)

Authority: AS 43.05.080 AS 43.55.110
AS 43.55.020(f) AS 43.55.150

AAC 55.190. CALCULATION OF REASONABLE COSTS OF TRANSPORTATION.

(a) Reasonable costs of transportation are to be calculated from the point of production to the sales delivery point.

(b) Actual costs of transportation for purposes of 15 AAC 55.180(a) are

(1) when the transportation of oil or gas is by a regulated carrier, the tariff on file with FERC or other regulatory agency having jurisdiction that is applicable to that transportation of the oil or gas by the carrier, from the point where that oil or gas is tendered into the facilities of the carrier to the point where it is delivered from the facilities of the carrier;

(2) when transportation of oil is by a tanker or other vessel that is not owned or effectively owned by the producer of that oil

(A) for a single voyage charter, the charter fee for that vessel, plus any voyage and port costs not included in that fee which are incurred with respect to that transportation during the term of the charter and which are borne by the producer, plus the positioning cost, if any, borne by the producer for that vessel; or

(B) for a consecutive voyage charter or a time charter, the charter fee for that vessel, plus any voyage and port costs not included in that fee which are incurred with respect to that transportation during the term of the charter and which are borne by the producer, plus the positioning cost (amortized over the lesser of 36 months or the term of the charter in the case of a time charter, and amortized on the basis of the number of voyages in the case of a consecutive voyage charter), if any, borne by the producer for that vessel; or

(C) for a contract of affreightment, the affreightment fee specified in that contract, plus any voyage and port costs and any positioning costs not included in that fee which are incurred with respect to that transportation during the term of the contract of affreightment and which are borne by the producer;

(3) when transportation of oil is by a tanker or other vessel that is owned or effectively owned by

the producer of that oil, the producer's actual cost for that transportation, which is the sum of

(A) voyage and port costs incurred with respect to that transportation;

(B) the positioning cost, amortized over 36 months, for that vessel;

(C) depreciation of the vessel; if the vessel is actually owned by the producer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for this asset; if the vessel is effectively owned by the producer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(D) an amount, which when added to the amount of depreciation allowed under (C) of this paragraph, will provide a reasonable return on the acquisition cost of the vessel over its expected life; for purposes of this subparagraph

(i) "acquisition cost" means the cost of the vessel which may be capitalized by its actual owner under generally accepted accounting principles, including costs of improvements made after the date the vessel is placed in service by or on behalf of the producer; and

(ii) "expected life" means the period of time used to calculate depreciation under (C) of this paragraph:

(4) in the case of transportation of gas as LNG

(A) where not all of the LNG transportation facilities are subject to tariff regulations (by FERC or other agencies of the United States, state or territory or a possession of the United States or a foreign nation) and when

the producer does not have or effectively have any ownership interest in the LNG transportation facility, the amount charged to the producer for that LNG transportation;

(B) when the producer has or effectively has an ownership interest in the LNG transportation facility, the producer's actual cost for that transportation which is the sum of

(i) the direct operating costs of the LNG transportation facility (in the case of an LNG tanker, its respective voyage and port costs) incurred with respect to the producer's gas;

(ii) the positioning cost, amortized over 36 months, for that vessel;

(iii) depreciation of the LNG transportation facility; if the facility is actually owned by the producer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for the owner of this asset; if the LNG transportation facility is effectively owned by the producer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(iv) an amount which, when added to the amount of depreciation allowed under (iii) of this subparagraph, will provide a reasonable return on the acquisition cost of the LNG transportation facility over its expected life; for purposes of this subparagraph, "acquisition cost" means the cost of the LNG transportation facility which may be capitalized by its actual owner under generally accepted accounting principles, including costs of improvements made after the date the LNG transportation facility is placed in service by or on behalf of the producer, and "expected life" means the period of time used to calculate depreciation under (ii) of this subparagraph;

(5) when the transportation of oil or gas is by a nonregulated pipeline facility that is not owned or effectively owned by the producer of that oil or gas, the transportation fee specified in the contract plus any other costs not included

in the fee with respect to that transportation which are borne by the producer;

(6) when the transportation of oil or gas is by a nonregulated pipeline facility that is owned or effectively owned by the producer of that oil or gas, an amount equal to that which would have been reported to the FERC or other regulatory agency having jurisdiction applicable to the transportation of oil or gas under (1) of this subsection, had the transportation been, in fact, under the jurisdiction of FERC or other regulatory agency for the tax reporting period.

(c) Reasonable cost of transportation under 15 AAC 55.180(b) is fair market value. Fair market value of transportation is to be determined

(1) for shipments of oil, on the basis of third-party charters (that is, time charters in which the producer does not own or effectively own the vessel) of one year or more, plus regulated transportation costs determined under (b)(1) of this section; two vessels will be considered like vessels for purposes of comparing like transportation under this chapter if the difference between them in tonnage is less than 10,000 dead-weight tons and if they are both Jones Act vessels, or are both CDS vessels, or are both ODS vessels or are both CDS/ODS vessels; or

(2) for shipments of gas as LNG, on the basis of third-party charters or leases (that is, charters or leases in which the producer does not own or effectively own the LNG transportation facility in question) of three years or more which are reported to the department for like LNG transportation facilities, plus regulated transportation costs determined under (b)(1) of this section.

(d) If a producer sells its oil or gas to a third party in what would otherwise be a bona fide, arm's-length sale but at the time of this particular sale the producer expects to repurchase that oil or gas at a subsequent time and place, then that sale to the third party and the repurchase from the third party, when it occurs, must be disregarded and the oil or gas subject to that sale must be regarded as if it had remained the producer's own oil or gas throughout the time between that sale and repurchase. In determining the value at the point of production in such

a case, the reasonable cost of transportation between the point of sale for that sale and the point of repurchase must be determined as if the producer were the shipper. This subsection does not apply if the producer's expected repurchase does not in fact occur.

(e) For purposes of this section, "voyage and port costs" for a vessel are costs actually incurred for fuel for the vessel while in port and at sea, stores and provisions for the vessel and her captain and crew, wages and benefits of the vessel's captain and crew, routine maintenance, port and dock fees, storage costs, demurrage, tug and pilotage fees, marine agents' fees in port, lightering, transshipment charges, customs fees and duties, regular and customary gratuities that are also legal, insurance premiums actually paid to third-party insurers, minor cargo losses or measuring differentials, loading and unloading inspection fees, Panama Canal transit fees, a reasonable management fee (to be prorated equally among vessels) for coordinating arrivals and departures into and out of ports for vessels owned, effectively owned or chartered by the producer, and other reasonable costs associated with the operation or maintenance (or both) of the vessel.

(f) A producer "effectively owns," has "effective ownership" or "effectively has an ownership interest" in a vessel, LNG transportation facility, or nonregulated pipeline facility for purposes of this section, if

(1) the vessel, LNG transportation facility, or nonregulated pipeline facility is owned by another person comprising part of a consolidated business in which the producer is also a part; or

(2) the vessel, LNG transportation facility, or nonregulated pipeline facility is the subject of a capital lease in which the producer or another person comprising part of a consolidated business in which the producer is also a part, is the lessee; or

(3) the vessel, LNG transportation facility, or nonregulated pipeline facility was built to the account of the producer (or another person comprising part of the consolidated business in which the producer is also a part), was sold and was chartered back by the producer (or another

person comprising part of the consolidated business in which the producer is also a part) all in a simultaneous transaction and the vessel or LNG transportation facility is on a term charter or lease to the producer (or another person comprising part of the consolidated business in which the producer is also a part) for a period of 15 years or longer.

(g) For purposes of this chapter, the "positioning cost" for a vessel includes the costs not included in the charter for that vessel which are borne by the producer for placing that vessel into position before the first voyage under that charter or the estimated costs to be borne by the producer for delivering it up at a specified location after the last voyage under that charter, or both if the producer is obligated under the terms of the charter or contract of affreightment to bear them both.

(h) A reasonable return under (b)(3)(D) or (b)(4)(B) of this section is presumed to be that amount which yields an internal rate of return (after federal income tax) on an investment which equals two percent plus the average annual national inflation rate (measured by the GNP deflator) during

(1) the period between the time the commitment is made to construct or acquire the vessel or LNG transportation facility and the time when the vessel or LNG transportation facility has been received (or delivered) and is ready to be placed into service; or

(2) if the period in (1) of this subsection falls entirely within a calendar year, that entire calendar year.

(i) At the request of a producer or on its own motion, the department will, in its discretion, replace the return under (h) of this section with one based on the rate of return imputed to that investment or similar ones by the person owning or effectively owning the vessel or LNG transportation facility.

(j) The third-party nature of an agreement between a producer and a third-party carrier regarding transportation costs is not affected during the term of that agreement by a subsequent consolidation of that producer and carrier into a

consolidated business, if, at the time they entered into that agreement, neither the producer nor the carrier exercised, directly or indirectly, any control over the business affairs of the other as the result of, or in anticipation of, their subsequent consolidation into that same consolidated business.

(k) For purposes of this section, a "pipeline facility" includes all facilities incident to the pipeline transportation of oil or gas downstream from the point of production as defined in 15 AAC 55.210. (Eff. 1/6/80, Reg. 73; am 5/21/81, Reg. 78)

Authority: AS 43.05.080 AS 43.55.110
AS 43.55.020(1) AS 43.55.150

15 AAC 55.200. RETROACTIVE ADJUSTMENTS. Retroactive adjustments in costs of transportation or sales price resulting from decisions of regulatory agencies, courts, or any other preemptive authority have a corresponding effect (increase or decrease) on the gross value at point of production as determined under this chapter, and the producer shall, within 90 days after those adjustments are made, file amended returns covering the entire period of an adjustment unless the producer has obtained a stay on such filing or payment, regardless of the pendency of appeals of those decisions. (Eff. 1/6/80, Reg. 73)

Authority: AS 43.05.080 AS 43.55.020
AS 43.05.280 AS 43.55.110

15 AAC 55.210. DEFINITIONS. Unless the context otherwise requires, as used in 15 AAC 55.010 - 15 AAC 55.210

(1) "area" means a geographic region or geologic province such as, but not limited to, the Cook Inlet basin or the North Slope;

(2) "FASB" means the Financial Accounting Standards Board;

(3) "FASB-13" means FASB's Statement of Financial Accounting Standards No. 13, "Accounting for Leases" (November 1976), as amended or interpreted by FASB's Statement of Financial Accounting Standards No. 17, "Accounting for Leases - Initial Direct Costs" (November 1977); FASB's Statement of Financial Accounting Standards No. 22, "Changes in the Provisions of Lease Agreements Resulting

from Refundings of Tax-Exempt Debt" (June 1978); FASB's Statement of Financial Accounting Standards No. 23, "Inception of the Lease" (August 1978); FASB Interpretation No. 19, "Lessee Guarantee of the Residual Value of Leased Property" (October 1977); and FASB Interpretation No. 21, "Accounting for Leases in a Business Combination" (April 1978):

(4) "field" means that part of an area underlain by one or more overlapping, contiguous, or superimposed pools such as, but not limited to, Prudhoe Bay field or Middle Ground Shoal field;

(5) "LNG transportation facility" means any or all of the following: the LNG liquefaction plant, gathering lines to that plant, loading and unloading facilities for LNG tankers, and LNG tankers themselves;

(6) "point of production" means

(A) for oil, the automatic custody transfer meter or unit through which the oil enters into the facilities of a carrier pipeline or other transportation carrier; and in the absence of an automatic custody transfer meter or unit, the "point of production" for oil is the outlet flange of the tank gauge (or in the absence of an automatic transfer meter or a tank gauge, another mechanism or device to measure the quantity of oil that has been approved by the department for this purpose) through which the oil is tendered and accepted into the facilities of a carrier pipeline or other transportation carrier;

(B) for gas recovered in association with oil, the meter on, or nearest (measured along the course taken by the gas) to, the lease or property from which the gas is recovered, at which meter the sales stream of gas is measured with sufficient accuracy and at appropriate temperature, pressure and other condition for purposes of sale, regardless of whether the particular gas in question is actually sold at that meter;

(C) for gas not recovered from or in association with oil, the point where it is accurately metered or measured, or if the gas is sold on the premises of the lease or

property from which it is recovered, then the point of such sale;

(7) "sales delivery point" means

(A) for a producer's oil and gas sold in a bona fide, arm's-length sale to a third party, the point of delivery specified under the terms of the contract or agreement for that sale, except in the case of a sale to which (C) of this paragraph applies;

(B) for a producer's oil not sold in a bona fide, arm's-length sale to a third party, the inlet of the refinery or comparable facility to which that oil is ultimately transported; and

(C) for a producer's gas not sold in a bona fide, arm's-length sale to a third party, the point of delivery under the terms of the sales contract being used as the reference for the calculation of sales price of the producer's gas under 15 AAC 55.160(b):

(8) "same market" means

(A) with respect to a producer's oil refined in Alaska, the Alaskan market;

(B) with respect to a producer's oil landed on the U.S. West Coast (including Hawaii), the West Coast market or, if appropriate, the submarkets on the West Coast (i.e., Puget Sound, San Francisco Bay, the Long Beach and Los Angeles area, and Hawaii);

(C) with respect to a producer's oil landed on the U.S. Gulf Coast, the Gulf Coast market;

(D) with respect to a producer's oil landed on the U.S. East Coast, the East Coast market;

(E) with respect to a producer's oil landed in Puerto Rico or the U.S. Virgin Islands, the Puerto Rican and Virgin Island market;

(F) with respect to a producer's gas marketed in Alaska, the Alaskan market or portion of it served by gas from the same field or area as the producer's gas;

(G) with respect to a producer's gas marketed in the Lower 48, the Lower 48 market;

(H) with respect to a producer's gas marketed in a foreign country, the market in that foreign country. (Eff. 1/6/80, Reg. 73)
Authority: AS 43.05.080 AS 43.55.110
AS 43.55.020(f) AS 43.55.150

15 AAC 55.9660. NUMBER OF OIL WELLS.
Repealed 7/1/77.

15 AAC 55.9670. DAILY PER WELL OIL PRODUCTION. Repealed 7/1/77.

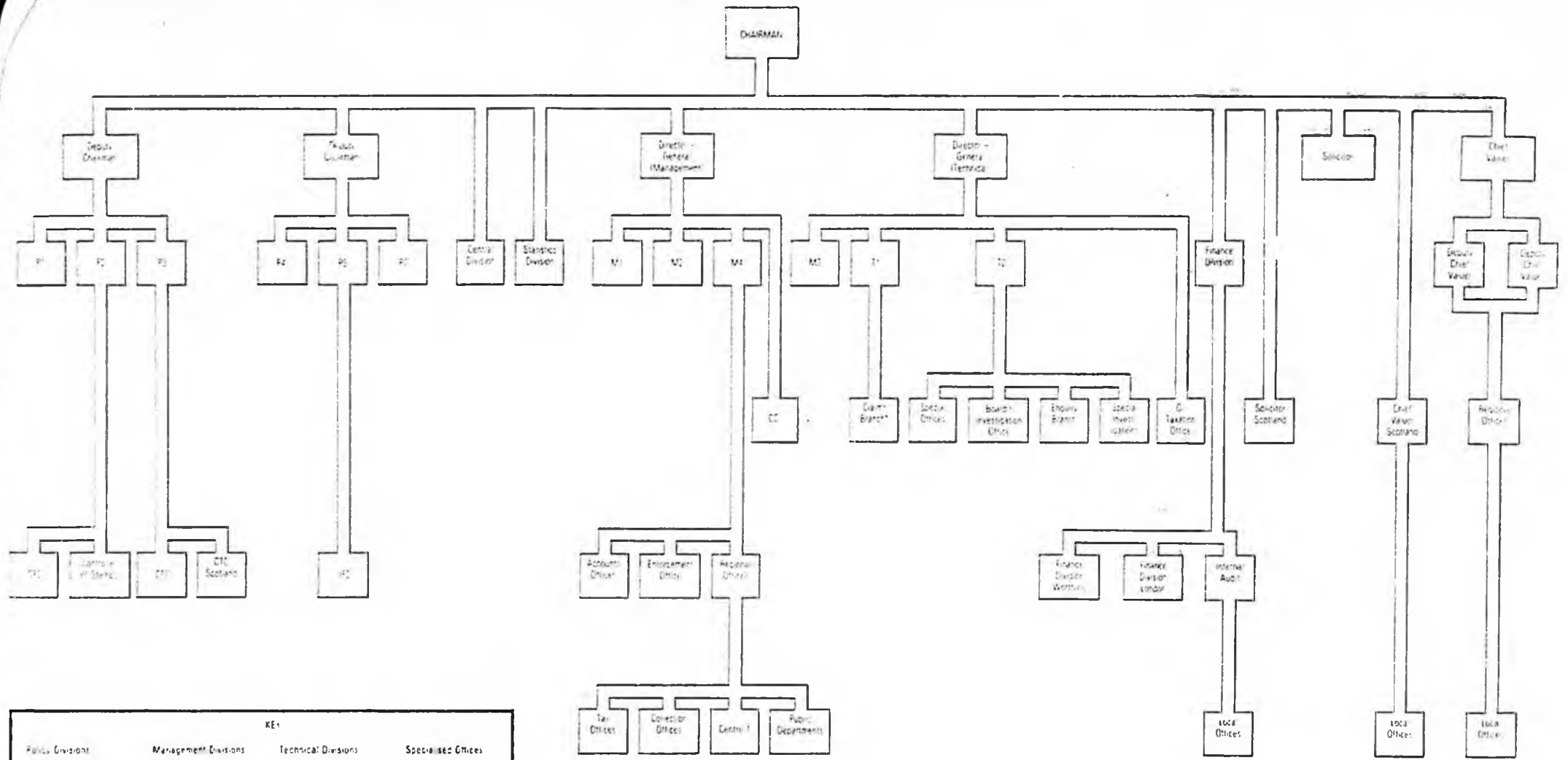
15 AAC 55.9690. SALES PRODUCTION RATIO. Repealed 3/7/74.

15 AAC 55.9694. TAX RATE CHANGES BASED ON WHOLESALE PRICE INDEX. Repealed 7/1/77.

15 AAC 55.9699. POINT OF VALUATION OF OIL. Repealed 1/6/80.

15 AAC 55.9700. DEFINITIONS. Repealed 1/6/80.

Inland Revenue - Organisation Chart



KEY			
Policy Divisions	Management Divisions	Technical Divisions	Specialised Offices
P1: Revenue Taxation	M1: Personnel and Training	T1: Business and other duties: Social Gains, Personal Taxation	CTO Capital Taxes Office
P2: Collection and Enforcement	M2: Manpower and Accommodation	T2: Counter assistance and special investigations: Taxation	IFD Inspector of Foreign Divisions
P3: Capital Gains Tax	M3: Information Technology		SFO Superannuation Funds Office
P4: Audit	M4: Operations		
P5: Investigation	CG: Communications Group		
P6: Taxation and Interest			* Inshore and Edinburgh



Inland Revenue
Petroleum Revenue Tax

Serves to supp. data box
for est'n of market value

Notes

1. Particulars are only required in respect of arm's length sales.
2. 'Oil' has the meaning given to it by Section 1(1) Oil Taxation Act 1975. A relevant sale is a contract for sale to which the participator, or any UK resident company which is associated with the participator, is a party as seller, buyer or otherwise, and which provides for delivery at any time within the chargeable period to which the return relates. Details of contracts which do not lead to physical delivery (bookouts) should be included.
3. The following contracts for sale are excluded -
 - a. Those which have been included in the participator's return (form PRT 1) made under paragraph 2 Schedule 2 Oil Taxation Act 1975.
 - b. Those which require delivery of less than 500 metric tonnes of oil.
 - c. Those which relate to the sale of gas consisting mainly of methane or ethane (or a combination of them).
4. A participator who is required to submit returns on forms PRT 1 in respect of more than one oil field is required to submit only one additional return for a chargeable period.
5. Where two or more participators in an oil field are members of the same group of companies only one participator is required to make a return of 'relevant sales'. (For this purpose two companies are members of a group of companies if one is the 75% subsidiary of the other or both are 75% subsidiaries of a third company.) In such a case the name(s) of the other participator(s) on whose behalf the return is being made must be entered in the space provided on the front page.
6. In any instances where the details contained in more than one return would be identical, eg where two or more participators who are members of the same group have interests in more than one field, only one such return need contain all of the details.

The name(s) of the other participator(s) should be entered on the front page of the complete return, and the other participat:or(s) should, in making his/their return(s), include a reference to the complete one.
7. It will assist processing of the return if the information about 'relevant sales' is presented so that contracts relating to various types of crude - eg Brent blend, Forties blend, Ninian blend etc, and of LPG - eg butane, propane etc - are grouped together, and so that sales are separated from purchases.
8. Where a transaction did not lead to a physical delivery specify under 'Date of delivery' the latest date for delivery under the contract, and under 'Quantity sold' the quantity of oil contracted to be sold. Enter 'B' (bookout) in the 'Notes' column.
9. Please use the 'Notes' column to identify any 'relevant sales' made under Term contracts (T); and to identify any contracts made on other than FOB and/or 30 days credit terms by stating the relevant particulars.
10. Where the price of oil is determined by reference to other prices, eg the average of specified published prices or of prices realised, please provide details on a separate sheet of the calculation of the contract price, together with a copy of the contract. If a copy of the contract has already been submitted to the Oil Taxation Office it will be sufficient to state the fact.
11. The price and the amount receivable should be stated in the currency used in the contract which will usually be US dollars. Please specify the currency where it is other than US dollars.

Oil Taxation Office
Melbourne House
Aldwych
London
WC2B 4LL
Tel: 01-438 6525

Participator's additional return

Under the provisions of Section 62(4) Finance Act 1987 you are required to complete this return and deliver it to me within two months after the end of the chargeable period. The notes on page 4 will help you to complete the return. It must contain a complete statement of all 'relevant sales' of oil (see notes 1, 2 and 3), as defined in Section 62(6) Finance Act 1987.

If you need further information please apply to this office.

When the return has been completed please ensure that the Declaration below is signed.

R M Elliss
Controller

This return is made by _____
Full name of participator

and is a return of my own relevant sales and those of the following participators

Declaration	Penalties	The Finance Act 1987 provides penalties for <ul style="list-style-type: none"> • failure to complete the return within the statutory period <i>Section 62(7)</i> • fraudulent or negligent delivery of an incorrect return <i>Section 62(8)</i>
--------------------	------------------	--

I declare that this return is correct and complete

Signed _____ Date _____

Status of signatory _____

UK registered office address
of participator making the return _____

Postcode _____

Crude oil

Date of delivery <i>see note 8</i>	Date of contract	Name		Type of crude <i>see note 7</i>	Quantity sold [or contracted to be sold] (barrels)	Price per barrel US \$ <i>see notes 10 & 11</i>	Notes <i>see notes 8 and 9</i>
		Seller	Buyer				

Other oil

Date of delivery <i>see note 8</i>	Date of contract	Name		Type of condensate or LPG <i>see note 7</i>	Quantity sold [or contracted to be sold] (barrels*/tonnes*)	Price per barrel*/ tonne* <i>see notes 10 & 11</i>	Notes <i>see notes 8 and 9</i>
		Seller	Buyer				

* delete as appropriate

Notes

Part A

General

Quantities of oil should be stated in the following units -

- a. Crude oil: Barrels measured at 60°F
- b. Condensates (and other hydrocarbons in a liquid state at a temperature of 15°C and at a pressure of one atmosphere (1.0132 bar)): Tonnes
- c. Butane, propane and ethane (LPG): Cubic metres at 15°C and a pressure of one atmosphere
- d. Ethane (gaseous) and other gaseous hydrocarbons: Cubic metres at 15°C and a pressure of one atmosphere.

The Oil Taxation Office may ask for a copy of the full assay and distillation analysis, or other appropriate analysis, of the oil shown in the return.

- Item 1. Please state the range of API^o in the form of extreme readings - eg 35^o - 35.5^o. In the case of LPGs (butane, propane and ethane (sold in liquid form)) the factor required is to convert cubic metres (measured at atmospheric pressure and 15°C) into metric tonnes. For ethane sold in gaseous form and other gaseous hydrocarbons please state the factor required to convert from cubic metres (measured at atmospheric pressure and 15°C) into megajoules or therms as appropriate (state which).
- Item 3. State the interests of the participators in the field in the quantities of oil stated in the return. If those interests have changed during the period please state the date(s) of change and the interests before and from that (those) date(s).
- Item 4. Please state here the total quantities of oil, defined as in 6. below, at the commencement of the chargeable period. It is not necessary to show the allocation between participators.
- Item 5. Please state the total quantities of oil delivered or relevantly appropriated during the period, and the allocation between participators.
- Item 6. 'Closing stock' is the quantity of oil won from the field which has not been disposed of and not relevantly appropriated, or which has been disposed of but not delivered, at the end of the chargeable period. Please state the total quantities and the allocation between participators.

Part B

Please state in metric tonnes each participator's share of oil (exclusive of excluded oil) won and saved from the field during the period. For this purpose 1100 cubic metres of oil which is gaseous at atmospheric pressure and at a temperature of 15°C is counted as equivalent to one metric tonne.

Part C

Notes relating to the tariff receipts allowance are printed at the head of Part C.

Penalties

The Act makes provision for penalties if you fail to submit the return within the statutory period (Schedule 2 paragraph 6), and if the return is fraudulently or negligently completed (Schedule 2 paragraph 8(3)).



Inland Revenue Petroleum Revenue Tax

sewes to reconcile estimates of production in PRT 1 for various participants/licenses.



Oil Taxation Office
Melbourne House
Aldwych
LONDON
WC2B 4LL
Tel: 01-438 6525

Return by Responsible Person

Under the provisions of paragraph 5, Schedule 2 Oil Taxation Act 1975 you are required to complete this form and deliver it to me within one month after the end of the chargeable period.

The notes on page 4 of the form will help you to complete the return. If there is not enough space in any part of this form please continue on separate sheets which will become part of the return. If you want further information please apply to this office. Unless otherwise stated statutory references are to the Oil Taxation Act 1975.

When the return has been completed please ensure that the Declaration on page 3 is signed.

R M Elliss
Controller

Part A

Statement of oil won and saved during the chargeable period

	Crude oil	Condensates	
1a. Please state the range of API ^o during the period	<input type="text"/>	<input type="text"/>	
	Butane	Propane	Ethane*
b. State the average factor(s) to convert cubic metres into metric tonnes	<input type="text"/>	<input type="text"/>	<input type="text"/>
	Ethane*	Other gas	
c. State the average factor(s) to convert cubic metres into megajoules or therms	<input type="text"/>	<input type="text"/>	

*see Note on item 1

Notes on completion

Expenditure incurred after 30 June 1982
unless alternative date under
S13(1)(b)OTA 1983 applies

Please give the following information in a supporting schedule

- the nature of the asset
- the date on which the expenditure was incurred
- the original cost, restricted as appropriate by Schedule 4, paragraph 2, OTA 1975

For dedicated mobile assets S2 and S3 OTA 1983

- the date of first use in connection with the field
- details of prior use and any previous relief
- details of any cessation of use *Sch 1 para 8 OTA 1983*

For non-dedicated mobile assets S1 OTA 1983 and S4 OTA 1975

- the date of first use in connection with the field
- the date on which its useful life is likely to end and details of any disposal *S5(7)OTA 1983*

Brought-in assets Sch 1 para 7 OTA 1983

Indicate in the supporting schedule(s) any brought-in assets for which information is supplied.

Apportionment

State the basis of any apportionment.

Supplement S7(6) OTA 1983

Where supplement has been restricted by reference to a disposal receipt, give details in a supporting schedule.

Penalties

Penalties are exigible under Paragraph 8 Schedule 2 OTA 1975 where an incorrect statement or declaration in connection with any claim is made fraudulently or negligently.



**Inland Revenue
 Petroleum Revenue Tax**

Reference
Consecutive number of claim

**Oil Taxation Office
 Melbourne House
 Aldwych
 LONDON
 WC2B 4LL**

Expenditure claim by Responsible Person

Use this form to claim expenditure allowable under Sections 3 and 4, Schedule 5, Oil Taxation Act 1975, and Section 3, Oil Taxation Act 1983.

The form must be completed by the Responsible Person appointed by the Board of Inland Revenue, for the oil field to which the claim relates, and should be sent with the accompanying schedules to the Oil Taxation Office at the address above. Please refer to the notes on page 4 when completing this form.

Part 1

Field _____

Full name of Responsible Person _____

Claim period from _____ to _____

Declaration

I declare that to the best of my knowledge and belief

- all the statements made in this claim and its supporting schedules are correct
- none of the expenditure which is the subject of this claim has been allowed on a claim under Schedules 5 or 6 of the Oil Taxation Act 1975 for this or any other oil field
- none of the expenditure claimed is of a type for which an allowance is prohibited by Section 3(4) of the Oil Taxation Act 1975.

Signature of Secretary or other proper officer of the Responsible Person _____

Status of signatory _____ Date _____

UK Registered Office address _____

Postcode _____

Expenditure and supplement

Part 2 Claim under Section 3, Oil Taxation Act 1975

Expenditure on:	Amount of expenditure 1	Amount qualifying for supplement S2(9)(b)(iii) & S3(5) 2	Rate of supplement 3	Supplement claimed 4	Total claim cols. 1 + 4 5
searching for oil S3(1)(a)					
relevant licences S3(1)(b)					
ascertaining the extent, characteristics or reserves of the field S3(1)(c)					
winning oil S3(1)(d)					
measuring the quantity of oil S3(1)(e)					
transporting oil a. tariff payments S3(1)(f)					
b. other expenditure					
initial treatment or initial storage S3(1)(g)					
disposing of oil crude S3(1)(h)					
closing down the field S3(1)(i)					
statutory redundancy payments less recoverable rebates S3(2)					
Total expenditure and supplement claimed £					

Part 3 Claim for long term assets

Enter below the total amount(s) claimed and attach supporting schedules. For associated and remote associated assets, please state on the schedule: a. the asset with which it is associated and b. the name of any person paying consideration for sharing field assets. Assets no longer in use for the principal field are to be identified with supporting information.

See Schedule 1, paragraphs 1-3, Oil Taxation Act 1983

Expenditure on:	Amount of expenditure 1	Amount qualifying for supplement S2(9)(b)(iii) & S3(5) 2	Rate of supplement 3	Supplement claimed 4	Total claim cols. 1 + 4 5
non mobile assets S3, OTA 1983					
dedicated mobile assets S2, S3, OTA 1983					
non dedicated mobile assets S4, OTA 1975, S1, OTA 1983					
Total claim for long term assets £					

Part 4 Summary

Total claim under Section 3, OTA 1975	Part 2, column 5	_____
Total claim for long term assets	Part 3, column 5	_____
Total expenditure and supplement claimed	£	_____

Part 5 Excess allowances for earlier periods S4(9), S4(10), OTA 1975

Participant	Share
Total of excess allowances for earlier periods £ _____	

Part 6 Participants' shares in expenditure and supplement

Participant	Interest in field (%)	Amount of expenditure	Amount of supplement	Share of expenditure and supplement Sch 5 para 2(4)(b)
Total claimed £ _____				



**Inland Revenue
Petroleum Revenue Tax**

Reference
Consecutive number of claim

**Oil Taxation Office
Melbourne House
Aldwych
LONDON
WC2B 4LL**

Expenditure claim by Participator

Use this form to claim expenditure allowable under Sections 3 and 4 and Schedule 6, Oil Taxation Act 1975, and Section 3, Oil Taxation Act 1983. The participator making the claim should complete and send it with accompanying schedules to the Oil Taxation Office at the address above.

Part 1 Field _____

Full name of Participator _____

Claim period from _____ to _____

Notes on completion

Long term assets

Expenditure incurred after 30 June 1982 unless alternative date under S13(1)(b)OTA 1983 applies

Please give the following information in a supporting schedule

- the nature of the asset
- the date on which the expenditure was incurred
- the original cost, restricted as appropriate by Schedule 4, paragraph 2, OTA 1975

For dedicated mobile assets (S2 and S3 OTA 1983)

- the date of first use in connection with the field
- details of prior use and any previous relief
- details of any cessation of use (Sch 1 para 8 OTA 1983)

For non-dedicated mobile assets (S1 OTA 1983 and S4 OTA 1975)

- the date of first use in connection with the field
- the date on which its useful life is likely to end and details of any disposal (S5(7)OTA 1983)

Brought-in assets (Sch 1 para 7 OTA 1983)

Indicate in the supporting schedule(s) any brought-in assets for which information is supplied.

Apportionment

State the basis of any apportionment.

Supplement (S7(6) OTA 1983)

Where supplement has been restricted by reference to a disposal receipt, give details in a supporting schedule.

Penalties

Penalties are exigible under Paragraph 8 Schedule 2 OTA 1975 where an incorrect statement or declaration in connection with any claim is made fraudulently or negligently.

Declaration

I declare that to the best of my knowledge and belief

- all the statements made in this claim and its supporting schedules are correct
- none of the expenditure which is the subject of this claim has been allowed on a claim under Schedules 5, 6 and 7 of the Oil Taxation Act 1975 for this or any other oil field
- none of the expenditure claimed is of a type for which an allowance is prohibited by Section 3(4) of the Oil Taxation Act 1975.

Signature of Secretary or other proper officer of the Participator _____

Status of signatory _____ Date _____

UK Registered Office address _____

Postcode _____

Expenditure and supplement

Part 2 Claim under Section 3, Oil Taxation Act 1975

Expenditure on:	Amount of expenditure 1	Amount qualifying for supplement S2(9)(b)(ii) & S3(5) 2	Rate of supplement 3	Supplement claimed 4	Total claim cols 1 - 4 5
searching for oil S3(1)(a)	_____	_____	_____	_____	_____
relevant licences S3(1)(b)	_____	_____	_____	_____	_____
ascertaining the extent, characteristics or reserves of the field S3(1)(c)	_____	_____	_____	_____	_____
winning oil S3(1)(d)	_____	_____	_____	_____	_____
measuring the quantity of oil S3(1)(e)	_____	_____	_____	_____	_____
transporting oil a. tariff payments S3(1)(f)	_____	_____	_____	_____	_____
b. other expenditure	_____	_____	_____	_____	_____
initial treatment or initial storage S3(1)(g)	_____	_____	_____	_____	_____
disposing of oil crude S3(1)(h)	_____	_____	_____	_____	_____
closing down the field S3(1)(i)	_____	_____	_____	_____	_____
statutory redundancy payments less recoverable rebates S3(2)	_____	_____	_____	_____	_____
Total expenditure and supplement claimed £	_____	_____	_____	_____	_____

Part 3 Claim for long term assets

Enter below the total amount(s) claimed and attach supporting schedules. For associated and remote associated assets, please state on the schedule: a. the asset with which it is associated and b. the name of any person paying consideration for sharing field assets. Assets no longer in use for the principal field are to be identified with supporting information.

See Schedule 1, paragraphs 1-3, Oil Taxation Act 1983

Expenditure on:	Amount of expenditure 1	Amount qualifying for supplement S2(9)(b)(ii) & S3(5) 2	Rate of supplement 3	Supplement claimed 4	Total claim cols 1 - 4 5
non mobile assets S3, OTA 1983	_____	_____	_____	_____	_____
dedicated mobile assets S2, S3, OTA 1983	_____	_____	_____	_____	_____
non dedicated mobile assets S4, OTA 1975. S1, OTA 1983	_____	_____	_____	_____	_____
Total claim for long term assets £	_____	_____	_____	_____	_____

Part 4 Summary

Total claim under Section 3, OTA 1975 Part 2, column 5 _____

Total claim for long term assets Part 3, column 5 _____

Total expenditure and supplement claimed £ _____

Part 5 Excess allowances for earlier periods Section 4(9) and Section 4(10) OTA 1975 £ _____

Part A

Enter details of the claims and final decisions as to supplement giving rise to each elected amount shown in column 7

Field of origin _____

Full name of participator in field of origin _____

2

	Date of claim	Schedule of claim	Claim no.	Date of final decision as to supplement - para 2(2) Schedule 14	Total amount of expenditure allowed as qualifying for supplement (excluding expenditure falling within S5A(1) OTA 1975) in the decision in column 4	Has there been a previous election in respect of the amount in column 5? If 'Yes' see Part C	Elected amount allowable in respect of the receiving field(s) and to be disregarded in the field of origin - S65(1) and (5)	Supplement to be disregarded in the field of origin as a result of the CFA election
	1	2	3	4	5	6	7	8
					£		£	£
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
				Total				

Part B

If more than one receiving field is shown on the front page complete Part B to show the apportionment between the receiving fields of each elected amount shown in Part A column 7 - para 1(2)(d) Schedule 14

3

Elected amount Repeat amount shown at corresponding line number in Part A column 7 £	Apportionment of elected amount between receiving fields		
	Name of field	Name of field	Name of field
	Amount apportioned to field £	Amount apportioned to field £	Amount apportioned to field £
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
Total			

Notes on completion

1. Complete Part A in all cases. Complete Part B if more than one receiving field is shown on the front page of this form. Complete Part C if there has been a previous election in respect of any of the expenditure in Part A column 5.
2. An election may be made in respect of expenditure incurred on or after 17 March 1987 by the participator making the election or, if that participator is a body corporate, by an associated company in connection with a relevant new field (the field of origin) if, in relation to that field the expenditure is allowable under Section 3 or Section 4 Oil Taxation Act 1975 or Section 3 Oil Taxation Act 1983, has been allowed as qualifying for supplement, and is not expenditure falling within Section 5A(1) Oil Taxation Act 1975 [exploration and appraisal expenditure] - Section 65(1) and (2).
3. No election may be made in respect of an amount of expenditure until a final decision as to supplement has been made on a claim in respect of that amount under Schedule 5 or 6 Oil Taxation Act 1975 - para 2(1) Schedule 14.
4. A participator may not make an election in respect of expenditure incurred before the date which is his qualifying date (Section 113 Finance Act 1984) in relation to a receiving field unless that date falls before the end of the first chargeable period in relation to the receiving field - Section 65(3).
5. Certain of the terms used in this form are defined by the statutory provisions listed below -

associated company	para 10	Schedule 14
elected amount	para 1(2)(a)	Schedule 14
final decision as to supplement	para 2(2)	Schedule 14
field of origin, receiving field...	Section 65(1)	
relevant new field	para 8	Schedule 14
6. The time limits for making an election are set out in paragraphs 2 and 3 of Schedule 14.



Ref. No.

**Oil Taxation Office
Inland Revenue
Melbourne House
Aldwych
LONDON WC2B 4LL**

NOTES ON COMPLETION

1. All statutory references on this form relate to the Oil Taxation Act 1975, unless otherwise indicated.
2. The details given in Parts 2 and 3 should provide full particulars of the amounts claimed including —
 - (a) the blocks to which each item of expenditure relates;
 - (b) details of any expenditure claimed which was incurred jointly with other persons including a description of the basis on which such expenditure has been apportioned;
 - (c) whether the whole or any part of the licence covering the blocks mentioned under (a) has been disposed of or surrendered and the extent and circumstances of any such disposal;
 - (d) any restriction required under Schedule 4, paragraph 2.
3. Where any expenditure claimed represents only a part of the total abortive exploration expenditure incurred in the calendar year in question this should be indicated and cross references made to any other claims for expenditure incurred in the same year.
4. Details should be given in Part 2 of the nature of the connection between the person incurring any expenditure claimed in B and the participator.
5. Separate details should be given in Part 3 for each asset included in the claim.
6. Where any qualifying receipts arise under S.5(6), which have been included in form PRT 1, reference should be made to these in completing Parts 2 and 3.
7. Where it has been necessary to apportion any item of expenditure full particulars of the basis on which the apportionment has been made should be included.
8. Details should be provided in a separate schedule of any asset which has been the subject of an allowance (computed under Section 5(2)) in any previous claims under Schedule 7, and which has since been disposed of.

SCHEDULE 7, OIL TAXATION ACT 1975

Claim by a Participator in an Oil Field for expenditure to be allowed under Section 5 Oil Taxation Act 1975

Abortive exploration expenditure incurred before 16 March 1983

This form should be completed by the Participator making the claim and sent with any accompanying Schedules to the Oil Taxation Office at the above address.

PART 1

Field for which claim is to be made

Full name of participator

DECLARATION

I declare that to the best of my knowledge and belief:

- (a) all the statements made in this claim and its supporting schedules are correct;
- (b) the expenditure which is the subject of this claim has not been allowed and is unlikely to become allowable on a claim under Schedules 5 or 6 or any other claim under Schedule 7 of the Oil Taxation Act 1975 for this or any other field;
- (c) none of the expenditure claimed is of a type for which an allowance is prohibited by Section 3(4) as modified by Section 5(4) of the Oil Taxation Act 1975;
- (d) all the expenditure claimed has been incurred wholly and exclusively for the purpose of searching for oil in the United Kingdom, the territorial sea thereof or a designated area and is not and is unlikely to become allowable under Section 3 or 4 for any oil field.

Signature of secretary or other proper officer of the participator

Status of signatory Date 198.....

U.K. Registered Office address

.....Postcode

PRT 60 (1983)

PART 2		CLAIM FOR ABORTIVE EXPLORATION EXPENDITURE OTHER THAN EXPENDITURE ON ASSETS WITH A USEFUL LIFE OF MORE THAN 12 MONTHS		
A	Expenditure incurred by the Participator	Description of expenditure	Date incurred	Amount
B	Expenditure incurred by a company associated with the Participator in respect of the expenditure for the purposes of Section 5(7)(c)			
TOTAL EXPENDITURE CLAIMED				

PART 3		CLAIM FOR ABORTIVE EXPLORATION EXPENDITURE ON ASSETS WITH A USEFUL LIFE OF MORE THAN 12 MONTHS			
Description of asset	Cost	Date expenditure incurred on acquiring the asset	Expected or actual useful life from date of acquisition	Dates between which asset was used for abortive exploration	Expenditure claimed
	£				£
<p>Note Please ensure that if an asset for which a claim has been made in this or any previous claim has been sold, details are included on form PRT 1 in accordance with Paragraphs 11 & 12 Schedule 8 Finance Act 1983.</p>					

Notes on completion

1. All statutory references on this form are to the Oil Taxation Act 1975 as amended by Finance Acts 1983 and 1985, except where otherwise shown.
2. The details given in Parts 2 and 3 should provide full particulars of the amounts claimed including -
 - a. the licence and block numbers to which each item of expenditure relates and the percentage interest in each block held by the participator or the associated company incurring the expenditure
 - b. details of any expenditure claimed which was incurred jointly with other persons including a description of the basis on which such expenditure has been apportioned, showing separately operator's and participator's costs
 - c. any restriction required under Schedule 4 Paragraph 2
 - d. in the case of a claim under Section 5A(2)(d) details regarding the expiry, determination, revocation or surrender of the licensed area in respect of which the expenditure is claimed.
3. Details should be given in Part 2 of the nature of the connection between the participator and the person incurring any expenditure claimed, if other than the participator.
4. Separate details should be given in Part 3 for each asset included in the claim.
5.
 - a. Where any expenditure has been reduced by the receipt of any sums under Section 5(6) details of the receipts should be separately identified in Parts 2 and 3.
 - b. Receipts from the disposal of oil won in the course of operations should be distinguished. Where a market value was necessary under Section 5A (5B) the claim should be noted accordingly.
 - c. Where any qualifying receipts arise under Section 5(6) which have been included in form PRT 1, reference should be made to these in completing Parts 2 and 3 (Part III Schedule 8 Finance Act 1983).
6. Where it has been necessary to apportion any item of expenditure full particulars of the basis on which the apportionment has been made should be included.
7. Where a notice of a proposed field determination has been given (Schedule 1 Paragraph 2 (a)) the area proposed is treated, for the purposes of claims under Section 5A, as having become a field when the notice was given. However expenditure may be claimed in respect of an area which was comprised within a notice of proposed determination, but which was subsequently not covered by the final determination.
8. In connection with item c. of the declaration on page 1, Section 5A(2) was amended by Section 90(2) Finance Act 1985 which introduced a territorial restriction. For expenditure incurred on or after 1 April 1986 the qualifying area of exploration and appraisal is restricted to the territorial sea of the United Kingdom or a designated area.
9. No relief is available for exploration and appraisal expenditure incurred before the participator's qualifying date in relation to a field. See Section 113 Finance Act 1984.
10. Penalties are exigible under Paragraph 8 Schedule 2 where an incorrect statement or declaration in connection with any claim is made fraudulently or negligently.



**Inland Revenue
Petroleum Revenue Tax**

Reference
Consecutive number of claim

**Oil Taxation Office
Melbourne House
Aldwych
LONDON
WC2B 4LL**

**Exploration and appraisal expenditure
Schedule 7, Oil Taxation Act 1975**

**Claim by a participator in an oil field for expenditure to be allowed
under Section 5A Oil Taxation Act 1975**

Use this form only for claims for expenditure incurred after 15 March 1983. The participator making the claim should complete and send it with any accompanying schedules to the Oil Taxation Office at the above address. Please refer to the notes on page 4 when completing this form.

Part 1

Field for which claim is made _____

Full name of participator _____

Declaration

I declare that to the best of my knowledge and belief -

- a. All the statements made in this claim and supporting schedules are correct.
- b. None of the expenditure when incurred related to a field in respect of any part of which consent for development had been granted, or a programme of development had been served on the licensees, by the Secretary of State for Energy.
- c. All the expenditure claimed has been incurred wholly and exclusively for one or more of the purposes specified in Section 5A(2) Oil Taxation Act 1975.
- d. None of the expenditure claimed is of a type for which an allowance is prohibited by Section 3(4) as modified by Section 5(4) Oil Taxation Act 1975.
- e. None of the expenditure has been allowed under Schedules 5, 6 or 7, Oil Taxation Act 1975 for this or any other oil field.
- f. Any expenditure claimed which has given rise to the receipt of any sum at the date of the claim has been reduced by the receipt in accordance with Section 5(6) as applied and amended by Section 5A(4)-(5C) Oil Taxation Act 1975.

Signature of Secretary or other proper officer of participator _____

Status of signatory _____ Date _____

UK Registered Office address _____

Postcode _____

Part 2 Claim for exploration and appraisal expenditure other than expenditure on assets with a useful life of more than 12 months

Expenditure incurred by the participant or a company associated with him in respect of that expenditure

Type of expenditure	Description of expenditure - see note 2	Date incurred	Amount £
For the purpose of searching for oil S.5A (2) (a)			
For the purpose of ascertaining the extent or characteristics S.5A (2) (b)			
For the purpose of ascertaining what are reserves S.5A (2) (c)			
For the purpose of making licence payments described in S.5A (3) S.5A (2) (d)			
Total claimed £			

Part 3 Claim for exploration and appraisal expenditure on assets with a useful life of more than 12 months						
Description of asset	Cost £	Date expenditure incurred on acquiring the asset	Expected or actual useful life from date of acquisition	Dates between which asset was used for exploration or appraisal	Blocks and licence numbers of areas in which asset used	Expenditure claimed £
Total claimed £						

Please note that if an asset for which a claim has been made in this or in any previous claim, has been sold, details are to be included on form PRT 1 in accordance with Paragraphs 11 and 12 Schedule 8 Finance Act 1983.

Total claimed £ _____

Part 4 Summary
Total of Part 2 £ _____ Total of Part 3 £ _____ Total expenditure claimed £ _____

Declaration

I declare that Parts 1, 2 and 3 of this return, including the attached schedules, are correct and complete.

Signed _____ Date _____

Status of signatory _____

Full name of participator _____

UK registered office address _____

_____ Postcode _____



Inland Revenue Petroleum Revenue Tax

Oil Taxation Office
Melbourne House
Aldwych
London
WC2B 4LL

Tel. 01-432 6525

Return by Participator

Under the provisions of paragraph 2, Schedule 2, Oil Taxation Act 1975, you are required to complete this form and deliver it to me within two months after the end of the chargeable period.

The return, including the schedule sheets attached, must contain a complete account of all oil, as defined in Section 1(1) of the Act, (i.e. all substances won other than methane gas won in the course of operations for making and keeping mines safe) which is or was included in your share of any oil won from the field. If appropriate, include information about oil won in an earlier chargeable period.

Throughout this form statutory references are to the Oil Taxation Act 1975, unless otherwise stated.

The notes within will help you complete the form. If you need further information please apply to this office.

R M Elliss
Controller

Notes

General

This return is in three parts. Part 1 consists of the summary printed on page 3; the supporting schedules; and the Declaration which relates to the entire return. Part 2 consists of monthly reconciliations of nominations; a summary of reconciliations and/or a statement in respect of nominations made for the chargeable period; and a reconciliation in respect of blended oil which has been nominated. Part 3 consists of details relating to tariff and disposal receipts; qualifying receipts and exploration and appraisal expenditure.

Throughout this return references to the following should be read as shown below:

- | | |
|--------------------------|---|
| 'the period' | the chargeable period which ended on the date stated above. |
| 'Secretary of State' | includes the Department of Commerce, Northern Ireland. |
| 'licences' | licences granted under the Petroleum (Production) Act 1934. It includes licences under Section 2 of that Act as applied by Section 1(3), Continental Shelf Act 1964 and the Petroleum (Production) Act (Northern Ireland) 1984. |
| 'disposal crude' | the disposal of oil whether or not it has undergone initial treatment (Section 12(1)). |
| 'market value' | except as otherwise stated, as defined in paragraphs 2, 2A and 3 Schedule 3 (as amended by Section 62 and Schedule 11 Finance Act 1987). |
| 'assumed delivery place' | as defined in paragraph 2(2)(b), Schedule 3. |

Penalties

The Act provides penalties for

- failure to complete the return within the statutory period *paragraph 3, Schedule 2*
- fraudulent or negligent delivery of an incorrect return *paragraph 8(1) and (2), Schedule 2*

Part 2

Monthly nomination reconciliation

See the notes on completion for guidance on filling in this form

Participant _____ Field _____ Month _____ Year _____

Delivery date 1	Nom. no. 2	Nominal volume		Amount delivered		Effective volume bbls. 7	Equity volume not nominated bbls. 8	Price \$ 9	Exchange rate 10	Nominated Proceeds # 11	MV of equity volume not nominated 12	
		Specific volume 3	Tolerance % 4	Equity 5	Other 6							
Totals			X		Y			Z	S		W	
Market value			Market value of excess (para 11(3) Sch 10 FA 1987)						[W (X - Y) / Z]			T
									Aggregate nominated proceeds [S + T]			

Part 2

"Nominations of blended oil" - Allocation of "aggregate nominated proceeds" to originating field interests

Participantor _____ Blend _____ Month _____ Year _____

See the notes on completion for guidance on filling in this form

Fields	Volume of equity production 1	Aggregate nominated proceeds
		2
		3
Total		

Notes

1. For each field enter the volume of "equity production". Note that this does not include the quantity of any excess delivery of RIK.
2. Enter the "aggregate nominated proceeds" for the blend (taken from the appropriate "monthly nomination reconciliation").
3. Enter the share allocated to each field proportional to volumes of "equity production"

Thus for field 1 the above is given by :

$$\text{Total "aggregate nominated proceeds"} \times \frac{\text{Volume for field 1}}{\text{Volume total}}$$

C									
---	--	--	--	--	--	--	--	--	--

Part 1

Participant _____ Field _____ Chargeable period ended _____ Schedule of relevant appropriations of _____

Date of appropriation		Nomi- nation no. 2	Method and manner of appropriation 3	Quantity appropriated Units 4	Market value at the material time					Assumed delivery place 6
day	1 month				Per Unit 5a	Foreign currency 5b	Exchange Date 5c	Rate 5d	Sterling or Sterling equivalent 5e	
							d.	m.		

Total

Total £

Total quantity in tonnes (crude oil and condensates) or '000cu metres (gases) for oil allowance purposes

--

Part 1

Participantor _____

Field _____

Chargeable period ended _____

Description 1	Quantity in transit 2	Other quantities		Market value of the quantity in 3.					Assumed delivery place 5
		3(a)	3(b)	Per unit 4(a)	Foreign currency 4(b)	Exchange date 4(c)	Exchange rate 4(d)	Sterling or sterling equivalent 4(e)	
Crude oil	Barrels	Barrels	Tonnes			d m			
Condensates	Tonnes		Tonnes						
								Total £	

Butane	Tonnes	Tonnes	Cubic metres ('000s)						
Propane									
Ethane (as a liquid)									
Other gas	Therms/ Megajoules*	Therms/ Megajoules*	Cubic metres ('000s)						
Ethane (gas)									
Other									
								Total £	

*delete as appropriate

Participator _____ Field _____ Chargeable period ended _____

A Chargeable tariff receipts and chargeable receipts from disposals

Enter below details of all amounts which are chargeable receipts attributable to the field in accordance with the provisions of Sections 6 & 7 and Schedules 1 and 2 OTA 1983, or which are to be treated as such in accordance with Paras 2, 5(3), 7, 11, or 12 Schedule 2 OTA 1983.

If the asset giving rise to a chargeable receipt has been used in connection with more than one field, the receipt should be attributed to one of those fields in accordance with Section 8(3), OTA 1983.

Details of any apportionment under Paragraph 3, Schedule 2 OTA 1983 should be provided on a separate sheet.

Chargeable tariff receipts (Section 6 and Schedule 2 OTA 1983)

If a tariff agreement has not already been supplied to the OTO please attach a copy.

For tariffs payable otherwise than in sterling please indicate, on a separate sheet, the sterling equivalent and the basis of translation. If the tariff was not payable in cash the nature of consideration and the basis used to calculate its value should also be shown.

Nature of use of asset or service/facility provided	Date of receipt	Amount received

Disposal receipts (Section 7 and Schedules 1 and 2 OTA 1983)

If the chargeable asset has been sold to or appropriated by a connected person state, on a separate sheet, the full name of that person and the original cost of the asset.

Nature of, or interest in, the asset	Details of any insurance claims admitted but not received	Date of receipt, admission of claim or cessation of use in connection with the field	Sterling amount or equivalent received and, if applicable, basis of translation

A Summary *from other side*

	Disposal receipts	
	Tariff receipts	
Less	Tariff receipts allowance	
	Total	

Tariff receipts allowance - S9 OTA 1983 - Please set out your computation on a separate sheet.

B Qualifying receipts arising from Schedule 7 expenditure *(Part III Schedule 8 Finance Act 1983)*

Enter particulars of any 'qualifying receipt' as defined in paragraph 10, Schedule 8 FA 1983, whether received by you or a person connected with you. If the sum was received otherwise than in sterling, please state the amount in both the foreign currency and its sterling equivalent and explain the basis of the conversion. Please provide sufficient information about related expenditure to enable the claim to be identified.

Amount received	Date of receipt	Name of recipient (if received by a connected person)	Related expenditure claimed	Date of claim

C Exploration and appraisal expenditure *(Part II Schedule 8 Finance Act 1983)*

This section is to be completed only if this is the first return made by you in respect of the field.

1 Has a claim under Schedule 7 been made in respect of exploration and appraisal expenditure to which Section 5A applies, and which relates to, or to a licence for, any part of the field.

- a. by you? Yes No
- or b. by a company associated with you in respect of that expenditure? Yes No
- or c. by the old participator, or a company associated with him, (because you are, or a company associated with you is a new participator within the meaning of Schedule 17 Finance Act 1980). Yes No

2 If you have replied yes to any part of question 1 above, please give the following details.

Amount claimed	Nature of expenditure e.g. well/seismic	Licence and Block number	Field against which claim was made	Full name of company concerned (if Yes to 1b or 1c)	Date of claim	Claim number

North Sea now offers 14 export crudes

Leo R. Aaiund
Refining editor

The casual observer of the North Sea crude oil production scene could be by now be hopelessly confused. That province is beginning to look a lot like Nigeria with a multitude of large and small oil deposits producing separately or linked into blends.

A close and constant watch on the region is necessary to keep the picture straight. To this end the Journal in this and a following issue will present the North Sea suite of assays. In this issue, analyses for 13 individual crudes or blends are printed running in alphabetical order from Argyll to Ekofisk. The next installment (OGJ, June 6) will complete the North Sea coverage, carrying an additional 13 assays running from Flotta to Thistle.

Presently, 14 individual crudes or blends are exported from the North Sea. As Fig. 1 shows, four systems and two giant fields dominate production. Table 1 lists all the producing fields—except newly onstream Hutton—plus several of future interest. Assays have been collected for all.

There are, of course, more fields listed than export streams because of blending. In addition, some 40 designated fields and finds of dubious or unknown potential are not shown on the map.

Assays for some crudes that may never appear unmixed are presented to indicate their influence on the blend or because they have never been published before.

One crude, Brent, is produced pure and is a major component in the Brent blend. This is a key U.K. crude. Shell and Esso, the field operators, produce pure Brent over the SPAR loading facility in the field. (SPAR is not an acronym. The Shell designers so designated the system because of its similarity in appearance to a conventional spar buoy.)

It should also be noted that a system such as the Brent does not day in and day out carry a blend with a specific contribution from each field. If, for example, Sullom Voe is shutdown because of weather, the Shell/Esso fields send most of their production to

Table 1

North Sea assays and field operators

Denmark

1. Dan*-Dansk Undergrunds Consortium (DUC)
2. Gorm*-DUC

Norway

1. Ekofisk*-Phillips Petroleum
2. Gullfaks*-Statoil
3. Murchison*-Conoco
4. Statfjord*-Mobil

United Kingdom

1. Argyll*-Hamilton Bros.
2. Auk*-Shell/Esso
3. Beatrice*-Britoil
4. Beryl*-Mobil
5. Brae*-Marathon
6. Brent*-Shell/Esso
7. Brent Blend*†
8. Buchan*-BP
9. Cormorant, North*-Shell/Esso
10. Cormorant, South (Cormorant "A")*-Shell/Esso
11. Dunlin*-Shell/Esso
12. Flotta*‡
13. Forties*-BP
14. Fulmar*-Shell/Esso
15. Magnus*-BP
16. Maureen*-Phillips Petroleum
17. Montrose*-Amoco
18. Murchison*-Conoco
19. Ninian Blend*
20. Statfjord*-Conoco
21. Tartan*-Texaco
22. Thistle*-Britoil

* Offshore production.

† Several field operators contribute to blend.

‡ Occidental and Texaco as field operators, contribute to blend.

§ Chevron and Union as field operators contribute to blend. BP later.

the offshore storage they have while the other fields move the oil to Sullom Voe storage. This means that at times the blend could contain perhaps X or perhaps Y Brent.

Following are some comments on new developments and crudes in the North Sea region.

U.K. The North Sea production system is still dynamic with production constellations still being created or expanded.

Last month, Northwest Hutton began production into the Brent system at 10,000 b/d with the objective of 100,000 b/d by year's end. A full scale analysis of this crude production sample has not yet been run. But a drill-stem test sample had a gravity of

38° API, sulfur content of 0.32 wt %, and a pour point of 25° F. A second sample has a gravity of 34.4° API.

Hutton is scheduled to be linked with the Brent system early next year. After that, the hectic pace of additions over the past 5 or so years should come to a stop because plans for Tern and Eider fields are now "on ice."

The two-crude Ninian blend will get a third contributor the second quarter of this year when Magnus field sends its crude south to Ninian central platform then to Sullom Voe. Peak production from Magnus is expected to be 120,000 b/d.

The veteran Forties field, the North Sea's largest, with a flow rate of over 450,000 b/d, will be joined by a smaller partner this summer. Brae field, as part of a \$2-billion development program by Marathon, will be connected to Forties transmission facilities. The new Brae "A" platform is designed to handle 100,000 b/d oil.

Assuming the preproduction analysis of Brae reflects its future quality, the North Sea's marker crude will become slightly heavier and higher in sulfur content.

Maureen is scheduled to begin in late 1983 or early 1984 as a single-field stream.

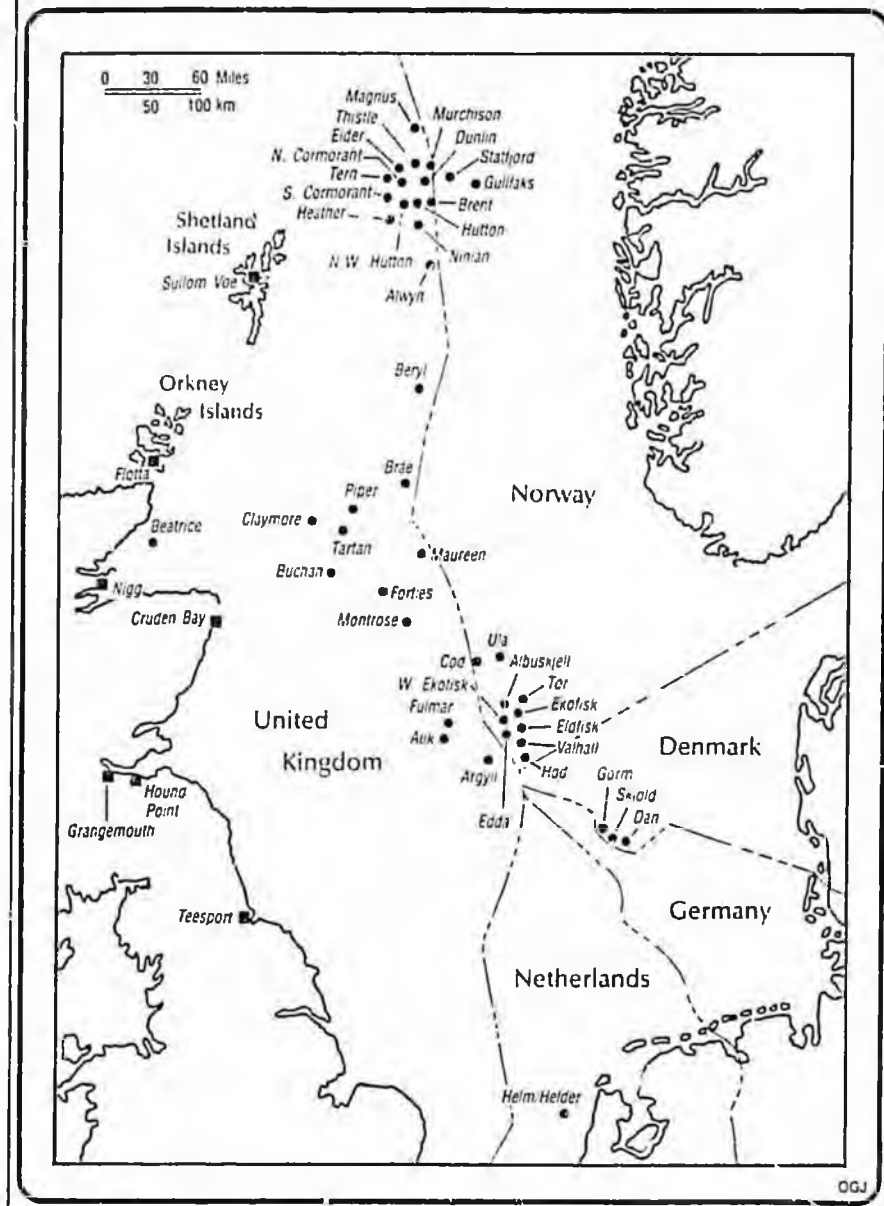
Norway. Norway's major North Sea system, Ekofisk, will enlist another contributor this year. Valhall "A" field will join the Ekofisk system. Hod field should be next in line.

Farther down the road, Norway plans to develop the Gullfaks field in block 34/10 which will give the region one of its most unusual crudes to date relative to those found. Its analysis reveals a gravity of 28.6° API. This could make it the heaviest crude produced in the North Sea (Piper field in U.K. waters runs a close second).

Gullfaks is expected to go into production in 1987 and become a major producer in the early 1990s.

In Statfjord field, a second production platform ("B") went into operation last fall, making the field the largest producer in Norwegian waters, with a flow of about 370,000 b/d. Peak rate will be even higher. The Ekofisk system produces some 300,000 b/d crude.

Major producers and prospects



Netherlands. The Dutch catalyzed the search for oil and gas in the North Sea with their huge gas finds onshore near Groningen in the early 1960s. Now, some two decades later, operators are finding the first commercial oil on the Dutch shelf. The first production from Helm and Helder fields came ashore last fall. Other fields in the area are slated for development.

Production to date is rather minor, and it is too soon to tell if the reserves would support exports.

Argyll, U.K. North Sea

SBM in producing area

Crude
Density @ 15° C.: 0.8549
Sulfur, wt %: 0.18
Pour pt., °C.: +6
Vis., cSt @ 40° C.: 4.79

Naphtha
Range, °C.: 160-175
Yield, vol %: 25.2
Density @ 15° C.: 0.723
Sulfur, wt %: <0.001

Kerosine
Range, °C.: 175-260
Yield, vol %: 14.9
Density @ 15° C.: 0.804
Sulfur, wt %: 0.03
Copper strip test: 1.A
Smoke pt., mm: 22
Freeze pt., °C.: -37

Gas oil
Range, °C.: 260-360
Yield, vol %: 18.9
Density @ 15° C.: 0.839
Sulfur, wt %: 0.11
Cetane index: 64.5
Cloud pt., °C.: 0
Pour pt., °C.: -3
Cold filter pt., °C.: -2
Vis., cSt @ 40° C.: 4.45

Residue
Range, °C.: 360+
Yield, vol %: 40.6
Density @ 15° C.: 0.9136

Key to the assays...

Each assay is headed, in the following order, by the official name of the crude, the former or secondary name in parenthesis, the country of origin, and location and type loading facilities. Loading systems that frequently crop up are abbreviated. Those used are CBM (conventional buoy mooring), SPM (single point mooring), SBM (single buoy mooring), CALM (catenary anchor leg mooring), and SALM (single anchor leg mooring).

Sulfur, wt %: 0.34
V/Ni/Fe, ppm: 3.9/2.1/2.7
Pour pt., °C.: +30
Vis., cSt @ 100° C.: 17.19

Auk, U.K. North Sea

SBM in producing area

Crude
Gravity, °API @ 60° F.: 37.15
Sulfur, wt %: 0.45
Wax, wt %: 6.5
Pour pt (ASTM max.), °C./°F.: +9/+50
Kin. vis., cSt @ 40° C.: 4.38
H₂S existent/potential ppm: <1/<1
Acid value, mg KOH/g (TAN): 0.13
Rvp, lb: 6
C₄—, vol %/wt %: 2.2/1.5

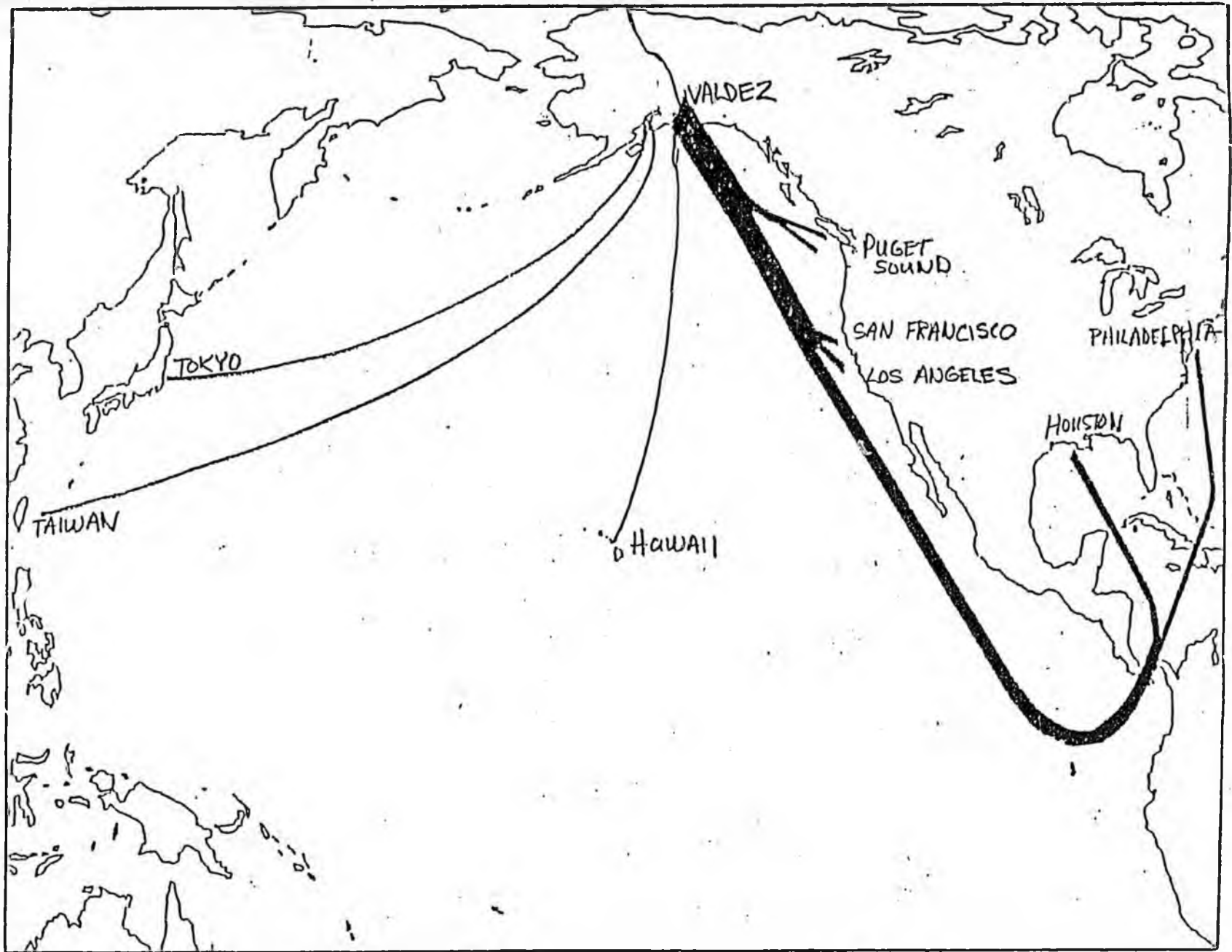
Gasoline
Range, °C.: C₅—85
Yield, vol %/wt %: 8.0/6.5
Sp gr @ 15° C.: 0.685
RON, clear: 66
RON + 0.5 g Pb/l Pb: 82

Naphtha
Range, °C.: 85-165
Yield, vol %/wt %: 15.5/14.0
Sp gr @ 15° C.: 0.755
Sulfur, wt %: 0.002
P/N/A, wt %: 51/34/15

Kerosine
Range, °C.: 165-235
Yield, vol %/wt %: 13.0/12.5
Sp gr @ 15° C.: 0.802
Sulfur, wt %: 0.01
Smoke pt., mm: 25
Aromatics, vol %: 19

Gas oil
Range, °C.: 235-300
Yield, vol %/wt %: 12.5/12.4
Sp gr @ 15° C.: 0.828
Sulfur, wt %: 0.09
Cetane no.: 60
Cloud pt., °C.: -19

Gas oil
Range, °C.: 300-350
Yield, vol %/wt %: 9.4/9.6
Sp gr @ 15° C.: 0.847
Sulfur, wt %: 0.35
Cetane no.: 63
Cloud pt., °C.: +9
Kin. vis., cSt @ 40° C.: 5.53



Tons \rightarrow barrels

reservoir knowledge / research program

getting tax records for oil cos. - biggest problem + delay

state has spent \$93m prosecuting tax / Am't cases -

43.21 - sep acctg

transp. costs -

in coast mktg histg Δ dramatically 2. x \rightarrow ARCO refg; exchanges -

volume-wtd contract price -

has this been tested? retroactively on past sales?

is the contract ^{volume} % likely to remain stable?

IMPORTANCE OF THE PETROLEUM SECTOR IN NORWAY

THE PETROLEUM SECTOR'S SHARE OF:

	1985	1986	1987
GNP	19%	12%	12%
NORWEGIAN EXPORTS	38%	29%	28%
GROSS INVESTMENTS (REAL)	22%	28%	
TOTAL STATE REVENUE	21%	15%	10%
EMPLOYMENT	0.5%	0.5%	0.5%

2

GUIDELINES REGARDING MARKETING OF NORWEGIAN OIL AND GAS

- MARKETING OF NORWEGIAN OIL BY THE COMPANIES INVOLVED SHALL BE BASED ON ORDINARY COMMERCIAL PRINCIPLES. THIS ALSO INCLUDES THE MARKETING POLICY OF THE STATE OWNED COMPANY STATOIL

- THERE IS NO RESTRICTIONS ON SALES OF NORWEGIAN OIL DUE TO FOREIGN POLICY CONSIDERATION APART FROM SELLING NORWEGIAN OIL TO SOUTH AFRICA

- COMPANIES INVOLVED IS SETTING THEIR OWN SALES PRICES; HENCE THERE ARE NO OFFICIAL SELLING PRICES SET BY THE GOVERNMENT

ORGANIZATION OF GAS SALES

- COMPANIES RESPONSIBLE FOR PLANNING AND SALES NEGOTIATIONS
- SALES CONTRACTS EVALUATED BY THE GOVERNMENT WHEN COMPANIES APPLY FOR DEVELOPMENT OF A FIELD
- COORDINATION OF GAS SALES BY STATOIL

4

DISPOSAL OF NORWEGIAN CRUDE OIL

- PRODUCING COMPANIES RESPONSIBLE
FOR MARKETING THEIR CRUDE OIL

- ROYALTY CRUDE TAKEN IN KIND AND
NOW SOLD TO STATOIL

- UNDERSTANDING ABOUT NO SALES OF
NORWEGIAN CRUDE OIL TO SOUTH
AFRICA

PRICING

- COMPANY RESPONSIBILITY

- NO OFFICIAL PRICES

- PRICES FOR TAXATION PURPOSES
(NORM PRICES) DETERMINED

- EX POST BY THE PETROLEUM PRICE
BOARD

DT.PRP. 26 (1974-75):

PETROLEUM TAX LAW

JUNE 13, 1975

WORMPRICE REGULATIONS

JUNE 25, 1976

6

WHY?

- Integration
- Concentration
- Size of the sector
- Difficult to control each sale

NORM PRICE

ADMINISTRATIVE

SIMPLIFICATION

7

"The norm price shall be equivalent to the price at which petroleum could have been sold between independent parties in a free market."

Indicators:

- Other prices
- Quality adj.
- Transport "
- Product prices

"THE NORM PRICE SHALL CORRESPOND TO THE PRICE AT WHICH PETROLEUM COULD HAVE BEEN SOLD BETWEEN INDEPENDENT PARTIES IN A FREE MARKET. "INDEPENDENT PARTIES" MEANS BUYERS AND SELLERS WHO MUTUALLY HAVE NO SUCH COMMON INTEREST AS COULD HAVE INFLUENCED AN AGREED PRICE. VALUATIONS SHALL TAKE INTO ACCOUNT AMONGST OTHER THINGS THE REALIZED QUOTED PRICES FOR PETROLEUM OF THE SAME OR EQUIVALENT NATURE, MAKING THE NECESSARY ADJUSTMENTS FOR DIFFERENCES IN QUALITY, TRANSPORT COSTS ETC. TO THE NORTH SEA AREA OR TO OTHER MARKETS CONCERNED, DELIVERY TIME, PAYMENT TIME AND OTHER TERMS, THE REALIZED AND QUOTED PRICES FOR PETROLEUM PRODUCTS, MAKING NECESSARY ADJUSTMENTS FOR PROCESSING ETC. AND ANY OTHER COMPARABLE PRICES OR VALUATIONS ETC. THAT MAY EXIST. CONSIDERATION SHALL BE GIVEN TO WHETHER THE AGREEMENTS ARE BETWEEN ASSOCIATED COMPANIES OR ARE SUCH THAT SPECIAL CIRCUMSTANCES OR OTHER CONDITIONS HAVE INFLUENCED THE STIPULATED PRICE."

ed by Saudi ever

THE PETROLEUM PRICE BOARD

6 MEMBERS:

- 8 yrs → MRS. KARIN BRUZELIUS (LEADER) - *ministry of communication*
- 12 yrs → MR. CHARLES PHILIPSON (DEPUTY LEADER) - *2. sep Ct. judge, was*
- 8 yrs - MRS. AINA UDHE - *economist / prof. exp. c. CITY court judge*
- MR. JARLE BERGD
- 12 yrs MR. KJELL MATHISEN (MIN. OF FINANCE) - *working*
- 2 1/2 yrs MR. ODD S. HARALDSEN (MIN. OF PETR. & ENERGY) - *was chair of the Board*
- + 4 yrs as dep.

2 DEPUTY MEMBERS

MR. EJARNE STAKIESTAD

MR. ERIK JOHNSEN

SECRETARIAT IN THE MINISTRY,

O: PETROLEUM AND ENERGY

DECISIONS WHEN 4 PRESENT AND

A MAJORITY OF 4.

PROCEDURE

- "EX POST"
- QUARTERLY
- COMPANY INFORM (3 weeks)
- BOARD'S "RANGE"
- COMPANIES COMMENT
(2 weeks)
- FINAL STIPULATION

PPB's information: 18

-sales reports

-other company info.

-secretariat "parity
calculations"

-general market info.

PARITY ARAB LIGHT -
EKOFISK

FOB-price Arab light
+ freight to Rotterdam
+ quality difference in
R'dam

= CIF-price Ekofisk in
R'dam

- freight to Teesside

FOB-price EKOFISK

NORM PRICE

CRUDE OIL 1975

NGL contract prices (PPB)

CONDENSATE - - - - -

NATURAL GAS

contract prices

^{P/}
APEAL PROCEDURE WHEN PPB STIPULATE THE NORM PRICE

1. THE COMPANIES CAN ASK FOR A SPECIAL COMMITTEE TO
ADVISE THE MINISTRY WHETHER THE PRICE WAS
STIPULATED "UNREASONABLY HIGH"

2. THE MINISTRY OF PETROLEUM AND ENERGY DECIDES ON
^{P/}
THE APEAL

3. NEXT STEP IS NORMAL COURT PROCEDURE

REGULATIONS RELATING TO THE STIPULATION OF NORM PRICES. ISSUED BY ROYAL DECREE OF 25 JUNE 1976 PURSUANT TO ACT OF 13 JUNE 1975 NO. 35.

Chapter I

Norm price for tax assessment purposes

Section 1

For tax assessment purposes, including the assessment of special tax pursuant to Act No. 35 of 13 June 1975 relating to the taxation of submarine petroleum resources etc. (The Petroleum Tax Act), norm prices may be stipulated for the different types and grades of petroleum or for parts of such produced in the areas mentioned in Section 1, a-b of the Act.

Section 2

The norm price shall be equivalent to the price at which petroleum could have been sold between independent parties in a free market. "Independent parties" means buyers and sellers who mutually have no such common interests as could have influenced an agreed price. For the valuation, account shall be taken, inter alia, of the realized and quoted prices for petroleum of the same or equivalent nature with necessary adjustments for quality variations, transport costs etc. to the North Sea area or to other possible markets, delivery time, time of payment and other terms, realized and quoted prices for petroleum products with necessary adjustments for processing etc. and other comparable prices or valuations which might exist. Consideration shall be given to whether the agreements are between associated companies or are such that special circumstances or other conditions have influenced the stipulated price.

The norm price shall be stipulated in arrears as a common price for petroleum produced during a specific period, normally for each quarter. If deemed appropriate, the norm price may be stipulated for a period shorter than one quarter.

For petroleum landed by pipeline, the norm price shall be stipulated on the basis of its value where landed. For petroleum landed by ship, the Ministry shall decide, after evaluating the selected means of transport, whether the norm price shall be stipulated on the basis of its value delivered at a North Sea port, or on the basis of its value at the production area shipment point.

In case of doubt the Ministry shall decide what is to be regarded as the landing point or the shipment point. The Ministry may make exceptions from the provisions of this paragraph when this is considered necessary or expedient in order to enforce the provisions relating to Norwegian taxation rights pursuant to legislation relating to taxation and charges or agreements with other countries concerning the taxation of petroleum activities etc.

Section 3

The

Unless otherwise indicated by special circumstances, the norm price shall be stipulated four times a year, normally for one quarter each time.

Provisional norm prices may be stipulated.

The parties involved are required to submit opinions on the norm price for each quarter, within four weeks after each of the first three quarters and within three weeks after the fourth quarter. Further, the authority that is to stipulate the price may call meetings with the parties for discussion and to obtain additional information. As far as possible each of the parties involved should also be given an opportunity to study the data etc. submitted by the other parties involved. The price stipulating authority may withhold internal documents, statements received and other documents which contain information concerning trade secrets etc. pursuant to the provisions of Sections 18 and 19 of the Administration Act.

Handwritten notes in a circle:
+ handle
6/15
5/7 - 87
in margin for
under
signature

Subsequently the price stipulating authority shall give the parties involved, in writing or at a meeting, a provisional evaluation of the price stipulation position. When the provisional evaluations are announced to the parties involved, the latter may submit opinions within two weeks. Longer respites for submitting opinions may be granted when the price stipulating authority finds reason to do so.

If possible the parties involved shall be notified and given a short respite to submit opinions when provisional norm prices are being stipulated. If after a provisional evaluation the price stipulating authority finds that no essential changes have occurred, it may decide that the last final norm price stipulated shall apply as a provisional norm price for subsequent periods.

When production is effected by two or more co-operating companies, the Ministry may demand that the group shall appoint in writing one or more representatives who are to receive notices, be called to attend meetings, submit statements, etc. on behalf of the group.

Section 4

The Ministry is authorized to stipulate provisional and final norm prices and to decide that norm prices shall not be stipulated for certain production areas. The Ministry may also decide that a stipulated norm price shall not apply to certain types or grades of petroleum or to parts of such.

Authority to adopt the resolutions mentioned in these regulations may be delegated by the Ministry to a special Petroleum Price Board.

Section 5

Petroleum Price Board resolutions relating to the stipulation of provisional or final norm prices may be appealed to the Ministry. Appeals shall have been received by the Petroleum Price Board within 30 days after adoption of the resolution. The other parties shall be

notified of the appeal and shall be entitled to join the appeal, even if no appeal has been filed by them before the expiry time limit.

In connection with appeals in accordance with the first paragraph of this Section against resolutions relating to the stipulation of final norm prices, the parties who filed the appeal or who subsequently joined the appeal may demand that the price stipulation be referred to a committee of experts to obtain their opinion as to whether the stipulated norm price is obviously inequitable, before any decision is made by the Ministry.

Requests for the appointment of such a committee of experts must be received by the Ministry not later than 14 days after the expiry of the time limit for appeals. The committee shall consist of three members appointed by the Chief Justice of the Supreme Court after the Ministry and the involved parties participating in the appeal have had an opportunity of submitting opinions concerning the appointments. The Committee shall allow the Petroleum Price Board and the parties who requested the appointment of a committee to present statements verbally or in writing, and otherwise collect such information as the Committee considers desirable. The Committee shall deliver its opinion not later than two months from its appointment.

The committee itself shall stipulate its fee and decide how payment of this fee and any other expenses incurred for the committee's work shall be divided between the parties.

Section 6.

Ministry resolutions relating to the stipulation of provisional or final norm prices may be appealed to the King when the resolution has been adopted by the Ministry as the first instance or if the Ministry has reserved a resolution previously adopted by the Petroleum Price Board without the resolution having been the subject of appeal.

The provisions of the first paragraph of Section 5 above shall apply accordingly.

Section 7.

General rules of administrative law and Section 35 of the Administration Act apply as regards a higher authority's power to reverse norm price resolutions at its own initiative, however the time limit for such reversal shall be six months from adoption of the resolution by the lower authority. The provision relating to notifying the lower authority pursuant to the second paragraph of Section 35 of the Administration Act, shall not be applicable to norm price resolutions.

Section 8.

Legal proceedings to try the validity of norm price resolutions may not be instituted unless the forms of appeal allowed pursuant to these Regulations have been employed. Otherwise Section 437 of the Civil Procedure Act shall apply accordingly.

Section 9.

Any person for whom the assesment of income and capital assets tax, including the special tax pursuant to Section 5 of the Petroleum Tax Act, will be based upon norm prices, is obligated to furnish all the information required for norm price stipulation. Such persons shall furnish of their own initiative also any further information that must be considered to have significance for the valuation of petroleum produced in the areas mentioned in Section 1, a-b, of the Petroleum Tax Act.

It may be required that information concerning the sales etc. of petroleum produced on the Norwegian continental shelf shall be furnished on special price statement forms issued by the Ministry. Price statements shall be forwarded to the Ministry each month. The time limit within which such statements shall be submitted will be stipulated by the Ministry.

Within 15 days from the end of each quarter, the price statements submitted shall be confirmed by the persons required to return such statements.

Any changes in submitted information shall be reported to the Ministry within 15 days after the person returning the statement has learned of the change.

Violation of the provisions of the preceding paragraphs is punishable by fines, cf. Section 339 No. 2 of the Penal Code, provided that no severer penal provision is applicable.

Section 10

The Petroleum Price Board shall consist of six members, appointed by the King.

The period of office for members and deputy members shall be two years. Different periods of office may be stipulated in particular cases to ensure continuity in the Board.

Resolutions may be adopted by the Board when at least 4 members are present and at least 4 vote in favour of the resolution. Discussion with the parties involved or the collection of information may be entrusted to a member or a committee or to the Board secretariat, as decided by the Board.

Chapter II

Norm price for royalty calculation

Section 11

The provisions contained in these Regulations shall apply accordingly for the stipulation of the royalty calculation basis or the calculation basis for provisional payments pursuant to Section 26 of the Royal

Decree of 8 December 1972 relating to exploration for and exploitation of petroleum in the seabed and sub-strata (as subsequently amended).

In all cases the calculation basis shall be stipulated on the basis of the value of the produced petroleum at the production area shipment point.

Chapter III
Norm price for consigned petroleum

Section 12

By issuing regulations or in the particular case, the Ministry may decide that the stipulation of prices for produced petroleum consigned under agreements concluded relating to Government participation in petroleum production on the Norwegian continental shelf, shall be based wholly or partly upon the provisions contained in these Regulations.

Chapter IV
General provisions

Section 13

For the purpose of this Decree, the Ministry means the Royal Ministry of Petroleum and Energy, petroleum means all liquid and gaseous hydrocarbons produced from the seabed and sub-strata as well as all other substances produced in conjunction with such hydrocarbons.

Section 14

The Ministry may issue regulations to implement the provisions of this Decree, issue complementary regulations relating to norm price stipulation by the Petroleum Price Board and issue regulations relating to Petroleum Price Board procedures.

Chapter V
Amendments

Section 15

Royal Decree of 8 December 1972 relating to exploration for and exploitation of petroleum in the seabed and sub-strata, shall be amended as follows:- - - -

Chapter VI
Entry into force

Section 16

These Regulations enter into force immediately.