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estimate of Sohio's depreciation each year. There were three Arco estimates in 1981, two in 1980, and one for each of 1978 and 1979. It was assumed that Sohio's depreciation number was applicable to 72% of field production and Arco's to 28%. This ratio reflects Sohio's 53% of overall production to the total production for which depreciation data are available (53% Sohio; 21% Arco). It is assumed that the missing data equals a weighted average of the available data.

For 1977, the only depreciation estimate was that based on Arco's production. Lacking any alternate estimate, it was used for that year. Since production in that year was relatively low, it is unlikely that changing the estimate by a reasonable amount will have a substantial effect on the results.

Per-barrel depreciation estimates for Prudhoe Bay are reported in Table II-2, above. Kuparuk depreciation is estimated at $2.91 per barrel. Although this estimate of Kuparuk depreciation is lower than that reported by some of the financial analysts discussed above, Barclay's reports that Kuparuk had an original estimated 1.9 billion barrels of recoverable crude oil. Given estimated investment in Kuparuk of $4.3 billion a depreciation charge of $2.28 per barrel (i.e. $4.3 billion/1.9 billion) is indicated. The $2.91 per barrel estimate may result in understatement of Kuparuk profit.

Total depreciation for each field is the product of crude oil production times the per-barrel amount. For non-ANS production, gas is converted to equivalent barrels using the standard 6 mcf of gas = 1 bbl. crude oil energy content ratio. It was assumed that non-ANS depreciation per barrel was 1/3 of ANS per-barrel depreciation. Use of this assumption yields total depreciation amounts that are relatively close to what one would expect given non-ANS investment and production levels. Total depreciation amounts for each year are presented in

Table II-3. These data represent the depreciation expense numbers included in the production profit estimates in Section III.

Table II-3
Total Depreciation Expense
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Total Alaska*
1987	$1,074	$ 263	$ 1,394
1986	1,110	253	1,418
1985	873	204	1,123
1984	710	117	866
1983	632	112	779
1982	581	83	698
1981	510		540
1980	476		504
1979	320		345
1978	254		280
1977	38		53
1976			16
1975			16
1974			16
1973			16
1972			16
1971			16
1970			17
1969			14
Totals	**$6,579**	**$1,032**	**$8,127**

SEVERANCE TAXES

Severance taxes are levied on the gross value of production which accrues to producers (i.e., working interest production). In Alaska, prior to 1981 severance taxes were 12.25% of production. Subsequent to 1981, the amount was revised to 15% of production (except that it remained 12.25% for the first five years of a field's commercial production). An economic limit factor is applied to production from each field which causes the actual severance tax to be lower than the statutory rate. The 1981 Legislation suspended the application of the economic limit factor at Prudhoe Bay until mid-1987. Prior to 1981, it was estimated that the severance tax on Prudhoe Bay production averaged approximately 11%. From 1982 to mid-1987, the Prudhoe Bay severance tax was estimated at 15%. From the middle of 1987 on, the Prudhoe Bay severance

tax was estimated at 12.25%.[9] Severance taxes on Kuparuk production have been estimated to range between an effective rate of 8% and 9%. A 9% rate was used for this study for Kuparuk. Recent severance tax returns suggest that by 1987 the economic limit factor reduced severance taxes on non-ANS Alaska production to close to zero. The effect of changes in the non-ANS depreciation amounts does not have a meaningful impact on reported profit.

To determine profit from oil producing activities, it is necessary to deduct severance taxes from revenues. Severance taxes are not reported separately for Alaska production in the annual reports of the producers. Therefore, the effective severance tax rates were applied to revenues reported here to obtain estimated severance tax expense for 1977 through 1987 for each field. For prior years, Alaska Department of Revenue reported collections were used as the severance tax expense. This amount corresponds closely to the expense that would be estimated if the statutory rate were applied to the production values.

The Alaska Department of Revenue reports severance tax collections from oil production in Alaska. Over time, severance tax expense as deducted to compute profit should tend to equal severance tax collections by the state. There is one significant wrinkle in this comparison. In 1975, the State levied a reserves tax which was allowed as a later credit against severance tax due later. The amount of the reserves tax was $493.7 million. This tax was considered a credit against severance tax payments due. Thus, when comparing severance tax collections to recorded expense, it is necessary to include this $493.7 million as a collection.

The estimated severance taxes for Prudhoe Bay, Kuparuk, non-ANS, and the total expense are summarized in Table II-4. These amounts are compared to

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[9]Effective severance tax rates are based on *Petroleum Intelligence Weekly* (February 1, 1988).

severance tax collections, including the reserves tax, as reported by the Department of Revenue. The results of the comparison indicate that the estimates are quite close to collections as they should be over time.[10]

Table II-4
Severance Taxes
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Non-ANS Alaska*	*Total Expense*	*Revenue Collections#*	
1987	$ 787	$ 85	$ 0	$ 871	$ 649	
1986	571	52	0	623	1,108	
1985	1,300	103	0	1,403	1,389	
1984	1,333	62	0	1,395	1,393	
1983	1,331	57	0	1,388	1,494	
1982	1,488	48	0	1,535	1,572	
1981	1,291		0	1,291	1,170	
1980	924		0	924	507	*
1979	622		0	622	174	*
1978	195		0	195	108	*
1977	76		0	76	295	*
1976			28	28	251	*
1975			27	27	27	
1974			22	22	22	
1973			11	11	11	
1972			11	11	11	
1971			11	11	11	
1970			8	8	8	
1969			6	6	6	
Totals	**$9,918**	**$ 406**	**$ 124**	**$10,441**	**$10,206**	

* Reflects differences due to reserves tax included in 1976 and 1977 collections but credited against later liabilities.

#Alaska revenue data are reported on a fiscal year basis. Company expense data are reported on a calendar year basis. This difference can affect some of the comparisons.

It is likely that some of non-ANS production during 1977 through 1987 incurred a severance tax liability. However, the amounts are too low to affect the analysis. Total severance tax expense reported in the analysis of profit is $10,441 million. Total actual tax collections amount to $10,206 million. The difference is 2.3%. It is possible that this difference is due to overstatement of effective severance tax rates or the delay between the time when severance

[10]Expense should exceed collections because collections are reported when received by the Alaska Department of Revenue and expenses are reported when the related production occurs.

taxes are due and when they are collected. The difference may also be due to the revenue estimates used. In any event, it is unlikely that the differences will have a significant effect on the results of the analysis.

OPERATING EXPENSES

Operating expenses are those costs which are necessary to continue production from an oil or gas field. They include well workover costs, fuel, maintenance and similar items. Information on these costs for the years 1980 to 1986 is available in the corporate annual reports of Sohio. Financial analyst reports include estimates of operating expenses as determined through meetings with company officials as well as based on their evaluation of operating costs.

For this report, operating expenses reported by Sohio were analyzed first. Sohio reports operating expenses combined with production taxes, windfall profit taxes and its net profits interest payments to BP America. It was necessary to separate production and windfall profit taxes from Sohio's reported data since these taxes are reported on another line in this income statement. The net profits interest payments to BP America would be an expense to Sohio, but a revenue item to BP America. This is a transfer payment between two field owners. The transfer payment needs to be cancelled when estimating income for the total project.

Net profits interest payments were reported in the notes to Sohio's financial statements. Severance taxes were estimated using the effective severance tax rates times the reported revenues. Windfall profit taxes were reported on a per-barrel basis in Arco's annual reports. These estimates were used to obtain an estimate of Sohio's windfall profit taxes. As described below, the resulting estimated windfall profit tax expense was lower than the reported windfall profit

tax collections by the U.S. Internal Revenue Service. As a result, the estimates of operating expenses may be higher than actual.

Table II-5 summarizes Sohio's reported production expenses, the computed estimates of severance and windfall profit taxes and the net profits interest payments to BP. The last column of Table II-5 is estimated operating expenses for the ANS based on the Sohio data.

Table II-5
Sohio's Operating Expenses
(millions of dollars)

Year	*Production Costs*	*Severance and Windfall Profit Taxes*	*Net Profits Interest*	*Operating Expenses*
1986	$ 727	$ 271	$ 44	$ 412
1985	1,216	680	108	428
1984	1,113	649	36	428
1983	1,021	699	0	322
1982	1,685	1,199	92	394
1981	2,550	2,030	153	367
1980	1,181	862	145	174

The resulting operating expenses were analyzed to see if they were mathematically related to revenues or production. It appeared that the operating expenses were not related to revenues and were only weakly related to production levels. Regression analysis, a statistical technique used to compare two sets of data (such as operating expenses and revenues), found no relationship between the numbers. This leads to the suggestion that these expenses are fixed costs. Further study of the expenses showed that they increased when the Prudhoe Bay waterflood project was installed and when the gas reinjection recovery program was installed. This further supports the suggestion that these costs are fixed with respect to annual production and revenues.

The best available overall estimate of production costs, then, is based on the relationship of Sohio's interest in Prudhoe Bay field. Thus, total ANS operating

expenses are estimated as equal to Sohio's operating expenses divided by Sohio's interest in Prudhoe Bay field. These expenses were subdivided between Prudhoe Bay and Kuparuk based on relative revenues from each field. Admittedly, this may misstate the precise relationship since operating expenses are not a function of annual revenues. However, there are no other direct operating expense data sources available publicly from the companies. The results of the calculations used for this estimate are presented in Table II-6.

Table II-6
Estimated Total Operating Expenses
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Total*
1987	$ 890	$ 218	$1,137
1986	662	152	845
1985	685	160	867
1984	726	120	850
1983	541	96	659
1982	651	92	771
1981	692		722
1980	328		335
1979	307		318
1978	261		289
1977	76		95
1976			28
1975			27
1974			23
1973			16
1972			14
1971			15
1970			15
1969			12
Totals	**$5,820**	**$ 837**	**$7,038**

Production costs for 1987 and for 1977 through 1979 were estimated based on an approximate relationship between revenues and these costs. Given the lack of other company data on these costs, reliance on revenues is one way available to approximate the operating expenses for the missing years.[11] There is a significant increase in the estimated operating expenses between 1980 and

[11]Although production costs are not related to revenues mathematically, there are relatively few options available for estimating costs attributable to each field. Since production costs are low relative to revenues, it is probable that the effect on reported profit is minor.

1981. This is probably due to the differences in windfall profit taxes included in the Arco data used to derive the windfall profit tax number and the Sohio data used as a basis for operating costs before deducting windfall profit taxes. As noted in the section on windfall profit taxes, Arco-based windfall profit tax numbers result in an expense that is lower than when using the I.R.S. collection data. It is possible that the use of Arco windfall profit tax numbers in the operating cost computation overstates operating costs with a resulting understatement of profit.

Other analysts such as *Petroleum Intelligence Weekly* and Salomon Brothers estimate that operating costs amount to an average of $1 per barrel of ANS crude oil production. *International Petroleum Finance* estimates operating costs at $.91 per barrel. The results here average $1.08 per barrel. Therefore, even though the expense number is calculated based on a number of assumptions, the outcome of the calculations follows closely, and conservatively, the costs indicated by other observers.

For 1984 to 1986, the operating costs per barrel for the Prudhoe Bay field should be greater than in prior years due to installation of the waterflood program. Since the method used here is based on a combined operating cost for Prudhoe Bay and for Kuparuk, it is probable that the costs for Kuparuk are somewhat overstated during 1984 to 1986 and the costs for Prudhoe Bay are understated by a like amount. The results could be a shifting of profit from Kuparuk to Prudhoe Bay in the amount of up to $100 million over the six-year period of Kuparuk operations. It does not appear that this is a significant amount relative to the profit for each field.

Production costs also include property taxes. Company data do not show the property taxes in Alaska separate from other production costs. Therefore, it is necessary to use alternate sources. Barclay's estimated Prudhoe Bay property

taxes at $.50 per barrel and Kuparuk at $.30. Non-ANS was estimated at $.25. The results were compared to Department of Revenue data and are comparable.

Production costs, net of property taxes, are obtained by deducting the property tax collections from the production costs reported in Table II6. Table II-7 shows the Alaska and municipal property taxes for the areas covered in this report. Table II-8 gives the production expenses net of property taxes.

Table II-7
Property Taxes
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Total*
1987	$ 150	$ 44	$ 197
1986	148	41	192
1985	150	35	188
1984	148	20	172
1983	147	17	159
1982	147	14	165
1981	146		151
1980	146		152
1979	123		130
1978	104		113
1977	30		31
1976			12
1975			13
1974			13
1973			13
1972			13
1971			13
1970			14
1969			13
Totals	**$1,438**	**$ 171**	**$1,754**

Table II-8
Operating Expenses
Net of Property Tax
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Total*
1987	$ 740	$ 174	$ 940
1986	514	110	653
1985	535	125	679
1984	578	100	678
1983	394	77	500
1982	504	78	606
1981	546		571
1980	182		183
1979	184		188
1978	157		176
1977	46		63
1976			14
1975			15
1974			10
1973			3
1972			1
1971			2
1970			1
1969			1
Totals	**$4,382**	**$ 666**	**$5,284**

WINDFALL PROFIT TAXES

The Crude Oil Windfall Profit Tax Act of 1980 levied a tax on the "windfall profit from a barrel of crude oil." The windfall profit was defined as the difference between the base price (essentially the price before oil price decontrol) and the selling price. The tax was in effect until 1988 although crude oil price declines rendered the effective amount of the tax at zero for years after 1985. In addition, ANS fields outside the Sadlerochit reservoir were exempt from the tax.

There are two primary sources of data concerning the windfall profit tax on Alaska crude oil production. The first is Arco's reported windfall profit tax per barrel of Alaska crude oil production. The second is the U.S. Internal Revenue Service *Statistics of Income Bulletin* which reported the aggregate windfall profit tax collections on ANS crude oil as a separate line item. Arco's per barrel windfall profit tax statistics are reproduced in Table II-9.

Table II-9
Windfall Profit Tax per Barrel
Arco Annual Report Data
($ per barrel)

Year	*Amount*
1985	$ .05
1984	.11
1983	.42
1982	1.59
1981	4.80
1980	2.03

To obtain the total windfall profit tax attributable to Prudhoe Bay, the Arco per barrel numbers were multiplied by field production. In addition, the Arco per barrel numbers were multiplied by the ratio of the all-company average field price to the Arco reported field price. This latter adjustment is designed to reflect the fact that other producers sold their ANS crude for a price that was different than that reported by Arco.[12]

Estimates of non-ANS crude windfall profit taxes were constructed by estimating the windfall profit on this crude and multiplying by a composite windfall profit tax rate. It was assumed that 1/2 of the crude was taxed at the 70% rate for old oil and 1/2 was taxed at a 30% rate. The base price was estimated as equal to the 1979 Cook Inlet price reported by DeGolyer and MacNaughton, adjusted for inflation for 1980 through 1985. The per barrel numbers obtained by this method were as follows in Table II-10:

Table II-10
Non-ANS Windfall Profit Tax
($ per barrel)

1985	$ 0.00
1984	1.42
1983	2.58
1982	5.46
1981	9.42
1980	1.91

[12]See Production Revenue section for further detail on this issue.

These per barrel amounts were multiplied by reported non-ANS production from column 1 of Table I-4 to obtain total windfall profit taxes for other Alaska production.

Estimated windfall profit taxes for Prudhoe Bay field and for all of Alaska are reproduced in column 1 of Table II-11. The computed amounts were compared to the reported collections from the *Statistics of Income Bulletins* shown in column 2 of Table II-11.

Table II-11
Windfall Profit Tax Expense
(millions of dollars)

Year	*Estimated for Prudhoe Bay*	*U.S. Internal Revenue Service ANS Collections*	*All Alaska*
1985	$ 26	$ 39	$ 39
1934	57	211	235
1983	215	426	475
1982	827	1,375	1,491
1981	2,487	3,089	3,314
1980	1,006	797	861
Totals	**$4,618**	**$5,937**	**$6,415**

Table II-11 shows that the U.S. Internal Revenue Service reported higher ANS windfall profit tax collections than those obtained using the Arco data adjusted for estimated price differences among the producers. The possibilities for these discrepancies are two-fold. First, the Arco-based revenue estimates may be too low as noted in the section on Production Revenue. Second, Arco may have had available to it adjustments to the windfall profit tax arising from the net income limitation provisions of the tax act. This part of the Act stated that windfall profit should not exceed 90% of the net income per barrel based on statutory computational rules. The net income limitation provision would not have been captured in the Internal Revenue Service data.

Column 3 of Table II-11 is the sum of the U.S. Internal Revenue Service reported ANS windfall profit tax collections plus the windfall profit taxes estimated for non-ANS production.

The difference between the two data sources is $1.3 billion. In the interest of providing a more conservative estimate of profit from Alaska oil operations, the higher figures of the Internal Revenue Service are used as the basis for Alaska windfall profit taxes.

EXPLORATION EXPENSES

Exploration expenses represent the costs incurred in finding new oil and gas deposits as well as certain costs incurred in defining an existing deposit. Data were not available to assign exploration costs to specific fields during this period. Moreover, there are few data series which overlap, so comparisons across estimates are not possible.

The U.S. Bureau of the Census provides data on Alaska oil industry exploration expenditures for 1978 to 1982 through its *Current Industrial Surveys.* The American Petroleum Institute *Joint Association Survey* provided the 1984 estimate of exploration expenditures. Both of these sources separated offshore expenditures from onshore. Presumably, the offshore expenditures were in Federal waters. These are the best sources of exploration expenditure data available, but they only were available for the years indicated.

For years prior to 1978, it was estimated that exploration expenditures totalled $25 million per year. This amount was compared to exploration drilling data obtained from the Alaska Oil and Gas Conservation Commission. The AOGCC provides numbers of wells drilled. The estimated exploration expenditures in 1969 to 1977 provided here would have financed the levels of drilling indicated by the AOGCC.

For 1983 and for 1985 to 1986 it was assumed that exploration costs equalled double the amount that Sohio reported as Alaska exploration expenses. It was assumed that 1987 exploration equaled 1986, although this is a conservative estimate. Comparing the amounts provided to the AOGCC drilling statistics indicates that these amounts would have easily financed the exploration activities reported by the AOGCC. Table II-12 shows the estimates of exploration expenses included in determining Alaska oil industry profit.

Table II-12
Exploration Expenses
(millions of dollars)

Year	*Amount*	
1987	$ 288	
1986	288	
1985	514	
1984	258	
1983	818	
1982	647	
1981	419	
1980	176	
1979	174	
1978	274	
1969 - 1977	25	annually
Total	**$ 4,081**	

OVERHEAD AND INTEREST EXPENSES

Overhead expenses are those that by their very nature cannot be traced directly to a particular activity. These costs are common to all activities in the company. The generally accepted accounting procedure is to allocate these costs to each activity that benefits from the cost on some basis that reflects either benefits received or cause-and-effect.[13] Frequently, as here, allocations are made in more than one step. Here, the first step is to allocate company overhead to Alaska operations. The second step is to allocate overhead to each field in Alaska.

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[13]See, for example, E. Deakin and M. Maher, *Cost Accounting 2nd. ed.* (1987), pp. 96 - 101. This topic has been addressed in detail by the former U.S. Cost Accounting Standards Board. The Cost Accounting Standards Board methodology is followed as closely as possible based on available data.

Sohio is the only producing company operating in Alaska from which sufficient data were available to make an allocation of overhead to Alaska activities based on assets and on revenues. In its corporate annual reports, Sohio presents segment information which, among other things, states Sohio's "Corporate and other" expenses. This line item was used as a proxy for the overhead cost.

To allocate this overhead, a two-factor formula was used. The two factors are value of crude production in Alaska to all company sales, and oil and gas property in Alaska to all Sohio property plant and equipment other than property plant and equipment related to the company's "corporate and other" activities.

Sohio data were available for 1977 through 1986. In 1987, BP America succeeded Sohio as a result of BP's buyout of the minority interest in Sohio. This purchase was accounted for by adding the extra funds paid to Sohio shareholders in excess of the book value of the assets received being attributed to the book values of the Sohio assets acquired. In effect, BP increased the accounting-based cost of its Alaska assets by a proportional amount of its payment to Sohio shareholders. This payment did not increase the actual costs expended in Alaska. Rather, it represented a transfer from BP to the former Sohio shareholders. As a result, the 1987 data necessary to perform the allocation would be affected by the amount of this transfer payment. Since this payment would result in attributing costs disproportionately to the actual costs incurred in Alaska, 1987 overhead was estimated by taking 1986 overhead and adding 4.5% for inflation.

A third factor commonly used in these formulas is payroll. These data are not publicly available. If the payroll data were available, the resulting allocation would be lower than that reported here because Sohio has proportionately fewer

employees in Alaska than the average of its assets and sales. The allocation method here used the value of Alaska production relative to total company sales. This ratio includes sales that have not been made to third parties. If third-party sales only were included, the allocation of overhead to Alaska operations would be lower than that reported here.

The result of this calculation is the first step in the allocation of Sohio overhead to all Alaska operations. Dividing the resulting allocation by Sohio's proportionate share in the Prudhoe Bay field yields an estimate of the total overhead attributable to Alaska by all producers. This is based on the assumption that other producers have a similar overhead structure to Sohio's and that the Prudhoe Bay ratio is a reasonable basis for estimating overall overhead. More complex allocations which include estimates of Kuparuk production have insignificant effects on the reported allocation.

To allocate to Prudhoe Bay and Kuparuk, overhead allocated to Alaska was subdivided in proportion to the revenues reported for Prudhoe Bay and Kuparuk. The original data used for the allocations and the results are give in Table II-13.

Table II-13
Overhead Allocations
(millions of dollars)

	-----Sohio Total-----			*-----Allocated to-----*		
Year	*Overhead*	*Assets*	*Revenues*	*Prudhoe*	*Kuparuk*	*Total*
1987				$ 109	$ 20	$ 139
1986	$ 234	$ 14,006	$ 10,022	105	20	133
1985	270	16,468	13,818	139	25	173
1984	160	16,421	12,251	89	11	106
1983	172	15,181	12,067	93	11	111
1982	132	14,347	13,529	77	8	91
1981	86	13,096	14,140	51		55
1980	24	8,506	11,346	15		16
1979	4	7,927	11,346	2		2
1978	-1	8,107	8,222	-		-1
1977	6	7,578	3,523	2		3
Totals				**$ 681**	**$ 94**	**$ 830**

This allocation assumes that overhead is proportional between Kuparuk and Prudhoe Bay. Such an assumption would usually be consistent with general accounting practices.

For lack of any data on the subject it was assumed that overhead for non-ANS activities was proportional to the revenues for those activities.[14] To obtain total overhead attributable to Alaska, the Prudhoe Bay and Kuparuk overhead were increased proportionately by the ratio of total Alaska production revenues to Prudhoe Bay and Kuparuk revenues. For years prior to 1977, overhead was estimated as a percentage of revenues based on the revenue percentage over the years 1977 through 1987. Overhead in each of the years prior to 1977 averaged less than $150,000.

Although these allocations are subjective and complex, they suggest that the overhead amounts are not so highly significant as to have a material effect on estimated profit. Aggregate overhead over the period of ANS production is estimated at $830 million. This is on the order of 2% of total profit. Even major changes in this number will have a minor effect on total profit.

To test one aspect of a source of variation in the overhead allocations, a composite estimate based on Arco's reported corporate and other expense using a two-factor formula was calculated. For most of the period at issue, Arco did not report its Alaska assets separately in its annual reports. These data were obtained from its SEC Form 10-K, Schedule VI.[15] Arco's total assets were obtained from its annual report segment disclosures. Total revenues were

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[14]Non-ANS overhead accounts for approximately 10% of the total overhead reported here. Similarly, non-ANS production is a small portion of total production in Alaska. In addition, as noted for the ANS, overhead is a small portion of overall costs and revenues. The effect of misstatements of the overhead will not have a significant impact on this analysis.

[15]In 1980 and 1981, Arco reported Alaska producing property plant and equipment in its annual report. The amounts were $1,087.7 million and $1,451.1 million respectively. The company reported Alaska property in its 10-K schedule for the same years as $1,789.2 million and $2,273.5 million respectively. The differences are substantial which suggests that the two series may not be comparable.

obtained from the annual report, but Alaska revenues had to be estimated by multiplying reported per barrel prices by reported Alaska production. Assuming that Arco accounted for 21% of Alaska activities and Sohio 51%, weighting the two overhead estimates gave a composite amount of $1,233 million over the period 1977 - 1987.

A second test of overhead variation is to construct an estimate using a payroll factor in the allocation formula. If Alaska payroll is assumed equal to 5% of each company's payroll, estimated overhead attributable to Alaska is $357 million over the period 1977 through 1987. The overhead amount included in the reported profit estimate is midway between these two numbers. Over the same period, the overhead estimate in this report averages 16.1¢ per barrel.

Interest expense was handled in a similar manner. Again, interest costs were based on data from Sohio's corporate annual reports because that was the only readily available source.[16]

Net interest expense for Sohio was reported in Sohio's segment disclosures in its annual reports or on the face of its income statements for 1977 through 1986. Since interest costs are related to the investment in assets rather than to sales, allocations of interest to Alaska were based on the ratio of property plant and equipment in Alaska to total company property plant and equipment. The result of this apportionment was the estimated interest expense attributable to Alaska.

The second step of the interest allocation required producing an estimate of interest attributable to Alaska by all producers. This was based on dividing

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[16]Arco reports some of the data required for this calculation, but the data are reported in different places which may not be consistent as noted in the overhead allocation discussion. It appears that Arco and Exxon experienced a lower overall rate of interest than Sohio. Therefore, Arco's and Exxon's interest costs should be lower than Sohio's. The amounts involved are small relative to the total reported income.

Sohio's assumed Alaska interest expense by its proportional interest in the Prudhoe Bay field. As with the overhead allocation, the results were not particularly sensitive to further refinement. The estimated total Alaska interest expense was subdivided between properties based on depreciation expense. This is more appropriate than sales because depreciation is considered more closely related to assets than to sales. Sohio's total company interest and assets and the resulting estimated interest allocations to the Kuparuk and Prudhoe Bay fields are given in Table II-14.

Table II-14
Interest Allocations
(millions of dollars)

	---Sohio Data---		*-----Allocated to-----*		
Year	*Net Interest*	*Assets*	*Prudhoe*	*Kuparuk*	*Total*
1987			$ 146	$ 32	$ 192
1986	$ 242	$14,006	139	32	183
1985	299	16,468	141	33	183
1984	242	16,421	119	20	148
1983	254	15,181	119	21	150
1982	300	14,347	139	20	171
1981	46	13,096	17		18
1980	22	8,306	10		11
1979	357	7,927	156		167
1978	458	8,107	203		247
1977	246	7,578	117		177
Totals			**$ 1,306**	**$ 159**	**$ 1,675**

The "net interest" column is Sohio's total corporate interest expense net of interest income. The "assets" column is Sohio's total assets less those designated as assets devoted to "corporate" (i.e., overhead) activities. Sohio's portion of net interest expense was allocated to Alaska based on the formula apportionment. The result was "factored up" to reflect an approximation of the total interest expense incurred by all Alaska producers.

For years prior to 1977, average estimated interest expense allocable to Alaska was less than $200,000 per year.

STATE INCOME TAXES

The State of Alaska levies an income tax on the income derived from oil and gas production operations in the State. During the 1977 - 1981 period, this tax was based on a direct measure of the income earned in the state. The statutory tax rate was 9.4% until 1981 when it rose to 11% for that year. Subsequent to 1981, the tax was levied using an indirect method referred to as modified formula apportionment. The latter tax is based not on a direct computation of the revenues accrued less expenses attributable to Alaska, but rather is based on a measure of the proportion of certain Alaska activities to overall company activities. The computed proportion is multiplied by overall company income to derive an estimate of income attributable to Alaska. *Petroleum Intelligence Weekly* suggests that the effective tax rate under this methodology is approximately 3%. As shown in Table II-15, a comparison of tax expense computed at the 3% rate is reasonably close to tax collections.

Individual company data on the Alaska income tax liability is not publicly available. The estimate of Alaska income tax is obtained by multiplying computed Alaska income by the effective tax rates for the periods at issue. The results are reported in Table II-15.

Table II-15
State Income Taxes
(millions of dollars)

Year	*Prudhoe Bay*	*Kuparuk*	*Total**	*Reported Collections**
1987	$ 83	$ 10	$ 92	$ 128
1986	37	2	37	134
1985	165	19	182	169
1984	171	11	189	265
1983	172	10	174	236
1982	168	8	175	669
1981	669		702	860
1980	550		556	548
1979	367		369	233
1978	67		66	33
1977	30		49	36
Prior to 1977			150	150
Totals	**$2,479**	**$ 60**	**$ 2,741**	**3,461**

*Alaska revenue data are reported on a fiscal year basis. Company expense data are reported on a calendar year basis. This difference can affect some of the comparisons. The collections include TAPS income taxes which are estimated to total $900 million.

The estimates differ from collections in part because of differences in the timing of when receipts are received by the State and when the expenses are reported on the income statements. Over the period 1969 through 1987, reported collections totalled $3.5 billion. The income statements here indicate total expenses of $3.6 billion, including the $.9 billion for TAPS. The differences are within a 5% margin of error.

FEDERAL INCOME TAXES

The U.S. government levies taxes on corporate income at statutory rates that ranged from 34% to 48% over the period 1969 through 1987. Under Federal rules, taxable income is net of state income taxes. Certain credits and deductions are allowed in the Federal taxing scheme which reduce the effective tax rates. It has been estimated that during the 1969 through 1980 period, the effective tax rates for oil companies averaged on the order of 29% (*Oil and Gas Journal*, (September 16, 1985), p. 76). This estimate was used for the 1969 to 1976 period.

For Alaska oil income after the start-up of Prudhoe Bay, this estimated Federal rate is unlikely to reflect actual Federal taxes. The taxes currently payable divided by estimated taxable income gives a number referred to as the effective tax rate. One important factor which results in a difference between statutory rates and effective rates is the Federal tax rules designed to provide an incentive to new investment like TAPS and tangible equipment on the North Slope. For example, an investment tax credit equal to 10% of the cost of tangible equipment was in effect during most of this period. This credit would serve to reduce Federal taxable income. That the effective tax rates were lower for Alaska producers may be seen by examining effective tax rates for these producers during the 1977 through 1986 period.

Effective tax rates for the major ANS producers were obtained from their corporate annual reports. The effective rate is the current Federal tax payments divided by reported net income. This information, as available, is reproduced in Table II-16.

Table II-16
Effective Federal Tax Rates

Year	*Arco*	*Sohio*	*Exxon*
1986	-55.49	-52.44	na
1985	40.94	41.53	23.18
1984	33.22	26.56	29.16
1983	19.68	31.60	33.81
1982	17.08	39.06	25.38
1981	16.23	36.41	23.93
1980	16.16	39.37	33.35
1979	12.30	11.22	35.29
1978	6.34	1.34	38.28
1977	na	10.19	na

It is widely presumed that Sohio's financial data was driven almost exclusively by its Alaska operations.[17] For this reason, Sohio's effective tax rates would tend to reflect the actual tax liability for Alaska oil operations during

[17]A review of Sohio's corporate annual repons from 1978 through 1986 indicate that over 90% of its profit arose from its Alaska activities.

the 1977 - 1986 period. Many oil companies, including the ANS producers, wrote-off substantial amounts from losing operations. The significant write-offs taken in 1986 resulted in negative Federal taxes for Alaska oil producers who accounted for most Alaska activities. Therefore, a zero effective Federal rate was used in 1986.

Although financial accounting standards for a company require that recognition be given currently to the possibility that some income tax benefits may need to be paid back to the government in the future, it appears from a review of the effective tax rates in Table II-16 that in this industry, the payback period continues to be deferred indefinitely. Use of current effective tax rates for the purposes of this study reflects better the economic consequences to the company of these investments than the use of statutory rates. In future years as tax benefits decline, these producers may be required to pay taxes in excess of the statutory rate.

With the merger of Sohio into BP, the assumption that Sohio's activities reflect Alaska closely would no longer hold. In addition, beginning in 1987, the tax law reduced many of the incentives for new investment. As a result, actual taxes are probably closer to the statutory rate. Therefore, the 34% statutory rate was used for 1987.

The Federal income tax expense used to estimate Alaska oil production income is reproduced in Table II-17.

These data were obtained by multiplying revenues from Table I-10 less expenses (covered in Tables II-3 (depreciation), II4 (severance taxes), II-6 (operating expenses), II-11 (windfall profit tax), II-12 (exploration expenses), II-13 (allocated overhead), II-14 (allocated interest), and II-15 (state income taxes)) by the related effective tax rates.

Over the entire period 1969 through 1987, Federal income taxes as shown in this report are 32.0% of estimated taxable income. This is higher than the 29% effective rates in the *Oil and Gas Journal* study. The net effect is that the estimates in this report are conservative and may tend to understate actual income.

Table II-17
Federal Income Taxes
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Total*
1987	$ 917	$ 105	$1,007
1986	0	0	0
1985	2,212	247	2,424
1984	1,469	91	1,627
1983	1,756	102	1,774
1982	2,125	104	2,212
1981	1,971		2,067
1980	2,086		2,110
1979	383		399
1978	9		8
1977	32		52
1976			63
1975			68
1974			66
1973			47
1972			44
1971			47
1970			47
1969			37
Totals	**$ 12,960**	**$ 651**	**$ 14,099**

III. PRODUCTION PROFIT

The result of all of the calculations in Sections I and II is to generate a statement which indicates the profit earned from oil and gas production in Alaska. This part of the report is divided into three parts: (1) profit for Prudhoe Bay, (2) Kuparuk and (3) all production in Alaska.

Table III-1
Profit from Prudhoe Bay Production
(millions of dollars)

1983 - 1987:

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

1977 - 1982:

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

Total profit over the eleven year production history of the Prudhoe Bay field are estimated as shown in Table III-2. The profit statements in Table III-1 are based on the producers' interest in the production. This is standard accounting practice, but the methodology excludes royalty interests which are important for the State of Alaska. Royalty interests have been estimated as equal to 1/7 of the producers' working interest less a gathering charge of $.63 per barrel. The state royalty is added to the producers' revenue to obtain revenues before royalty as shown in Table III-2.

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

Production Revenue	$ 83.5
Less Expenses:	
Depreciation	6.6
Operating Expenses	4.4
Overhead	.7
Interest	1.3
Royalty	10.0
Severance Taxes	9.9
Property Taxes	1.4
State Income Taxes	2.5
Windfall Profit Tax	5.9
Federal Income Taxes	13.0
Profit	**$ 27.8 Billion**
Profit per barrel: $5.81	

The estimate of profit from the Kuparuk field is also based on the combination of the data from Sections I and II of this report and is reproduced in Table III-3.

Table III-3
Annual Kuparuk Production Profit
1982 through 1987
(billions of dollars)

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

Combining the data for the six years of Kuparuk production gives overall Kuparuk profit as shown in Table III-4. State royalty was computed for Kuparuk in the same manner as for Prudhoe Bay.

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

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

Oil industry profit from production activities in Alaska are shown on a year-by-year basis in Table III-5.

Table III-5
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1983 - 1987:

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

1978 - 1982:

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

Table III-5 (continued)
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1973 - 1977:

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

1969 - 1972:

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

a. Less than $1 million

Total industry profit from production for the years 1969 through 1987 are shown in Table III-6, below. State royalty was computed in the same manner as for the Prudhoe Bay field.

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

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

Profit per barrel: $4.96

As stated throughout the report, this is the best estimate available of Alaska oil industry production profit. There are, however, some questions concerning the profit numbers which are necessary to understand the possible range within which the actual profit number might fall.

Revenue Issues. As noted in Section I, revenues have been estimated based on a weighted average of all producers. The resulting revenue amount is 1.19% greater than that which would be obtained using Sohio's data alone. The question is what effect would using estimated realizations have on the reported profit numbers. Over the production history of the Alaska North Slope, approximately 50% of ANS crude was sold on the U.S. West Coast where net realizations are approximately $1.40 greater than sales on the Gulf Coast

(Barclay's, 1988, p. 3). West Coast sales have been made almost entirely by producers other than Sohio. Under this assumption, revenues would increase by $1.8 billion with a resulting increase in after-tax profit of $ 1.0 billion. This was determined by taking the estimated average realization of $17.68 for Sohio and adding the extra value of West Coast sales for 50% of production. This step indicates that this approach would yield an additional average realization of $.37 per barrel over all 4.8 billion barrels of working interest production.

A second issue related to revenues is the 1986 Arco severance tax settlement. Arco paid $243 million in this settlement. Assuming that Arco's annual report data were based on its original pricing methodology, and that the severance tax rate was 15%, this would imply that the Arco revenue data which was used in this analysis understated revenues by $1.6 billion. After allowing for 15% severance tax, 3% Alaska income tax and 34% effective Federal income tax, the net profit effect is a $.8 billion increase. Part of the settlement may have been interest, but it is also likely that the settlement rate was less than 15%. If the net effect of these two factors is to offset each other, as expected, the profit increase suggested here is supported.

An additional revenue issue is the 1988 $171 million settlement on income taxes by Arco. The extent to which this settlement affected revenues and expenses is not public information. Presumably there would be an addition to the relevant items in the Arco income statements if those statements had been prepared on the basis which Arco used for its Alaska income tax. To the extent that the financial statements relied on here are the same as that used in the tax return, profit would be understated.

It should be noted with respect to both of these settlements with Arco that they are not final settlements. The outcome of ongoing litigation and its effect on profit estimates cannot be ascertained at this time.

Depreciation Expense. For the Prudhoe Bay field, the per barrel depreciation estimates used amounted to $2.15 in 1987, $2.25 in 1986 and $1.75 in 1985. *Petroleum Intelligence Weekly* (February 1, 1988) estimates Prudhoe Bay depreciation at $2.25, $2.17 and $1.53 for those years, respectively. On average for those years, this suggests that the depreciation estimates reported here may be too high by approximately $.07 per barrel. If this is the case, depreciation for Prudhoe Bay may be overstated by $336 million over the eleven-year production history. After a 3% Alaska income tax and a 34% estimated Federal income tax, this would imply that profit is understated by $217 million.

As noted in Section II, other sources have estimated Kuparuk depreciation at up to $3.80 per barrel, which is $.89 per barrel more than the average estimate included in this report. If these other estimates are correct, this would imply that Kuparuk depreciation needs to be increased by $307 million. This would decrease Kuparuk after-tax profit by approximately $198 million.

Operating Costs. This report indicates that operating costs, including property taxes were $1.08 per barrel over the life of Prudhoe Bay field. *International Petroleum Finance* estimates these costs at $.91 per barrel. *Petroleum Intelligence Weekly* estimates them at approximately $1.03 per barrel. This suggests that the estimate in this report may be between $.05 and $.17 per barrel greater than other estimates. At $.05 per barrel, after-tax profit would increase by $153 million and at $.17 the effect would be a $522 million increase in profit.

Windfall Profit Taxes. Based on Arco's estimates, total Prudhoe Bay windfall profit tax would equal $4.6 billion. Using the U.S. Internal Revenue Service data, windfall profit tax collections for the ANS totalled $5.9 billion. The latter number was used even though the net income limitation provisions of the tax act may have served to reduce the expense. On the other hand, the data reported by Arco would have been before any settlement of audit differences. The indicated range for windfall profit tax expense is, therefore, $1.3 billion before tax and an estimated $ .8 billion after tax, subject to possible adjustments as a result of settlements. Profit reported here may, therefore, be too low by up to $ .8 billion.

Overhead. As noted in Section II, overhead included in this report was estimated at $ .8 billion for the period of Prudhoe Bay production. Had a weighted average based on Arco's and Sohio's data been used in a two-factor allocation, overhead would have increased by $ .4 billion, which translates into an approximately $ .3 billion after tax decrease in profit compared to the amounts reported here.

On the other hand, using a three-factor formula for estimating overhead based on the Arco/Sohio composite results in overhead of $ .4 billion, which is $ .4 billion less than the amount used in this report. This would imply that profit had been understated by $.3 billion after tax.

Interest Expense. Analysis of the interest costs of Arco and Sohio suggests that the differences attributable to this factor amount to less than $50 million. Since adequate data are not available and since the amount is low relative to the total profit, this analysis has not been pursued further.

Federal Income Taxes. The estimated effective tax rate for Alaska oil production for this report is 32.1%. This is equal to the $14.2 billion in income taxes divided by pre-tax income of $44.3 billion. If the Federal income taxes had

been based on the estimated 29% effective tax rate for the industry, income taxes would have decreased by $1.0 billion, with a corresponding decrease in reported profit to producers.

Using the effective tax rates for the primary Alaska oil producers given in Table II-16, the unweighted average current effective tax rate is 26.3% for 1978 to 1985. The rate is negative in 1986. Had the Federal income taxes in this report been based on the average effective rate for the producers over this eight-year period, the amount would have been $11.5 billion, which is $2.7 billion less than that included in this report. This amount would pass directly through as an increase in profit of $2.7 billion.

Summary. The questions raised in this section cannot be resolved without additional data. For this reason, the effect of the different assumptions on profit are summarized so that one can adjust the results according to their own interpretation of the data. The effect of each assumption is given in Table III-7.

Table III-7
Effect of Assumptions on Profit
(billions of dollars)

Item	Increase in Profit	Decrease in Profit
Use of West Coast prices	$ 1.0	
Arco severance tax settlement	.8	
Outside Prudhoe depreciation estimates	.2	
Outside Kuparuk depreciation estimates		$ .3
Use of *Petroleum Intelligence Weekly* operating costs	.2	
Use of *Petroleum Finance* operating costs	.5	
Use of Arco windfall profit tax data	.8	
Composite two-factor overhead		.3
Three-factor overhead	.3	
39% Federal tax rate	1.0	
Composite company rate	2.7	
Total increases	$ 7.5	
Total decreases		$ 0.6

A review of these alternative estimates indicates that the profit reported here is within a reasonable range of actual profit and is probably on the conservative side.

IV. TAPS PROFIT

GENERAL METHODOLOGY

A review of data sources on the Trans Alaska Pipeline System indicates that the annual reports filed by Sohio Pipeline Company reflect quite closely a .3334 interest in pipeline revenues and expenses. This occurs in part because nearly 100% of Sohio Pipeline Company's activities are related to TAPS. Effective tax rates were used to estimate Federal income taxes for the reasons stated above. Sohio Pipeline Company reports were available for 1978 through 1987. Due to the short production period in 1977, the pipeline probably broke even or had such a small profit or loss that it would not affect the results.[18] For 1985 through 1987, Sohio Pipeline Company provided a separate statement of TAPS revenues, costs and profit. Most of the costs were incurred jointly through Alyeska and, thus, would be shared by all pipeline owners *pro rata*. The remaining expenses appear quite close to those indicated by other observers as appropriate for TAPS in total. Operating data in Table IV-1 represent the information reported in the Sohio Pipeline Company annual reports divided by .3334. Alaska income tax estimates were based on an effective rate of 9.4% during 1978 to 1981 and an effective rate of 3% thereafter. The Federal rate was estimated in the same manner as for production.

The amounts reported in Table IV-1 were compared to other sources. Property taxes were compared to the Alaska Department of Revenue's *Revenue Sources* reference. The amounts are quite similar.

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[18] 1977 throughput would have been approximately 28% of 1978 throughput. This would imply revenues of $690 million. Operating and administrative expenses are estimated at one-half of 1978. Depreciation would probably have been proportional to throughput. Property taxes would have been the same as in 1978. Interest expense would be approximately $236 million for an estimated before-tax loss of $20 million, which is not significant relative to other revenues and expenses.

Table IV-1
TAPS Profit Projected from Sohio Pipeline Co.
(millions of dollars)

1983 through 1987:	*1987*	*1986*	*1985*	*1984*	*1983*
Revenues	$2,765	$3,080	$3,578	$3,926	$3,899
Expenses:					
Operating and Administrative	255	343	247	387	483
Depreciation	351	364	363	507	558
Property Taxes	147	164	168	171	165
Interest	150	440	411	570	579
Alaska Income Taxes	56	53	72	69	63
Federal Income Taxes	633	0	993	609	669
Profit	**$1,174**	**$1,716**	**$1,325**	**$1,614**	**$1,382**

1978 to 1982:	*1982*	*1981*	*1980*	*1979*	*1978*
Revenues	$3,896	$3,605	$3,554	$2,963	$2,394
Expenses:					
Operating and Administrative	498	474	435	330	381
Depreciation	549	507	591	495	417
Property Taxes	168	171	168	174	174
Interest	648	681	720	771	846
Alaska Income Taxes	61	167	154	112	54
Federal Income Taxes	795	645	645	102	9
Profit	**$1,178**	**$ 961**	**$ 842**	**$ 980**	**$ 513**

Arco reported TAPS depreciation in its 10-K's for 1981 through 1987. The amounts were factored to reflect 100% depreciation for TAPS as shown in Table IV-2. The amounts for depreciation obtained in this manner were 38% lower than the amounts obtained from the Sohio analysis. Over the life of TAPS, the depreciation estimate is based on a weighted average of the Sohio and Arco depreciation data. The weighted average is based on Arco's 22% interest in TAPS and Sohio's 33% interest. The method assumes that the missing data are equivalent to the weighted average of the data that are available. The resulting depreciation expense number is $700 million lower than it would have been using the Sohio data alone.

Table IV-2
Arco-based TAPS Depreciation Estimates
(millions of dollars)

Year	*Arco 10-K*	*Estimated Total*
1987	$ 60.0	$ 272.3
1986	60.0	272.3
1985	60.0	272.3
1984	60.0	272.3
1983	58.9	267.7
1982	57.3	260.5
1981	80.4	365.5

Reducing the depreciation estimate increases taxable profit and income taxes. Alaska income tax was increased by $34 million based over the life of TAPS. Federal income tax was increased by $204 million over the same period. Apportioning the depreciation adjustment over the life of TAPS to date results in the schedule of TAPS profit shown in Table IV-3.

Table IV-3
TAPS Profit
(millions of dollars)

1983 through 1987:

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

Table IV-3 (continued)
TAPS Profit
(millions of dollars)

1978 to 1982:

	1982	*1981*	*1980*	*1979*	*1978*
Revenues	$3,896	$3,605	$3.554	$2,963	$2,394
Expenses:					
Operating and Administrative	498	474	435	330	381
Depreciation	467	431	503	421	355
Property Taxes	168	171	168	174	174
Interest	648	681	720	771	846
Alaska Income Taxes	63	203	162	119	60
Federal Income Taxes	802	599	617	129	8
Net Profit	**$1.250**	**$1.046**	**$ 949**	**$1.019**	**$ 570**
Profit per barrel	**$2.42**	**$2.15**	**$1.95**	**$2.49**	**$1.64**

Estimates of revenues and expenses included in this report were compared to information provided in connection with the TAPS settlement methodology. It appears from comparison with the data available to us that the revenue estimates here are approximately $400 million greater than indicated by the TAPS settlement data. The alternate estimates of operating and administrative expenses for 1978 to 1984 are within approximately $50 million. The estimates of Federal income taxes are lower in this report because the other sources used the statutory rate for tax expense purposes. Since the long-run relationship between before-tax profit and tax expense shows that the statutory rate overstates actual tax outlays, the effective rate is used in this income computations.

TAPS settlement data from Deloitte Haskins and Sells indicate that operating expenses average $.58 per barrel. The estimate in this report is $.64 per barrel. The Deloitte Haskins and Sells data indicate depreciation of $.59 per barrel. Before the Arco adjustment, the estimate in this report was $.80 per barrel. After the Arco adjustment, the estimate here is $.68 per barrel. The Federal income

tax allowance indicated from the Deloitte Haskins and Sells (DH&S) analysis of TAPS costs is $.75 per barrel. The estimate in this report is $.86 per barrel. The expense estimates used in the profit estimates reported here are consistently higher than those indicated by DH&S. Thus, profit reported here is lower than would be indicated using the DH&S data.

Barclay's de Zoete Wedd (1988) estimate cash costs of $.65 per barrel for TAPS. This would include operating and administrative costs plus property taxes. The estimate of these costs in this report is $.92 per barrel. Barclay's de Zoete Wedd estimates depreciation at $.80 per barrel, which is the same as used here after accounting for the Arco adjustment.

Petroleum Intelligence Weekly estimated that pipeline profit was $2.18 per barrel in 1985, $.64 per barrel in 1986 and $.53 per barrel in 1987. The estimates used in this report are $.75, $.94 and $.60 for each of those years respectively. Over the three-year period, they estimate a total profit of $6.1 billion. The profit reported here is $4.2 billion before the depreciation adjustment.

For the years 1983 through 1987, Arco reported the net income after tax of Arco Pipeline Inc., which holds Arco's interest in TAPS. Assuming that all of the income of Arco Pipeline is related to TAPS (which appears to be the case),[19] TAPS income for each of these years projected from the Arco Pipeline data would be $1.3 billion, $1.3 billion, $1.5 billion, $1.4 billion and $1.4 billion for a total over the five-year period of $6.9 billion. The estimate based on Sohio data is $7.2 billion. A weighted average estimate of profit based on 21.4% Arco ownership and 33.34% Sohio ownership gives a profit estimate for the four-year period for which both data series are available of $7.1 billion, which is within 2% of the estimate reported here.

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[19]TAPS income so completely dwarfs income from other pipelines that substantially all the income is attributable to TAPS.

Each of the sources which has looked into TAPS revenues, profit and costs has developed varying profit estimates. It appears that the adjusted profit indicated in Table IV-3 represent a "middle-of-the-road" estimate. Over the period of TAPS operation, estimated total profit is as follows in Table IV-4:

Table IV-4
Total Estimated TAPS Profit
(billions of dollars)

Revenues	$ 33.7
Expenses:	
Depreciation	4.0
Operating and Administrative	3.8
Interest	5.8
Property Taxes	1.7
Alaska Income Tax	.9
Federal Income Tax	5.1
Profit	**$12.4 Billion**

V. OTHER INFORMATION

Downstream Profit. The profit data which have been developed in this report do not include any profits earned beyond Valdez. It has been reported elsewhere that producers may earn between $.25 and $1.00 per barrel in profits on tanker and trans-Panama canal shipping operations. These profits serve to reduce the net cost of Alaska oil landed on the U.S. West and Gulf Coasts.

There is some evidence that U.S. West Coast prices are lower because of Alaska oil production than they would be without Alaska production. This occurs because prices of crude oil on the U.S. West Coast tend to average $1.00 per barrel less than prices on the U.S. Gulf Coast. If imported crude oil had to be substituted for Alaska crude on the U.S. West Coast, prices there would be at least equal to prices on the U.S. Gulf Coast. Indeed, a substantial argument can be made that prices on the U.S. West Coast would be greater than Gulf Coast prices because shipping costs for imported crude oil would be greater f.o.b. the West Coast than the Gulf Coast. Thus, there can be additional refining profits from Alaska crude which have not been included in this analysis.

These downstream profit issues are beyond the scope of this project. They do indicate, however, that the producer's economic benefits of Alaska oil production extend beyond the profit obtained within the boundaries of the State of Alaska.

Shares. The revenues from Alaska oil and gas production and transportation go to pay for costs incurred in those activities, state taxes and royalties, federal taxes and profit to the producers. The shares of revenues received by the producers, state and federal governments are itemized in Table V-1.

Table V-1
Shares
(billions of dollars)

	Producers	*State*	*Federal Government*
Royalties		$ 11.8	
Severance taxes		10.4	
Property taxes*		3.5	
Income taxes		3.6	$ 19.4
Windfall profit taxes			6.4
Production profit	$ 30.2		
TAPS profit	12.4		
Totals	**$ 42.6**	**$ 29.3**	**$ 25.8**
Percentages	**43.6%**	**30.0%**	**26.4%**

* Includes local property taxes.

Profit as an Hourly Rate. Forty-two billion dollars is a significant number and one that is difficult to put in perspective. Relating the number to an hourly rate over 10.5 years of production (91,980 hours at 24 hours per day, 365 days per year) gives a rate of $463,144 profit received after tax.

Return on Investment. It is also possible to relate profit received by Alaska producers to the investment made in TAPS and production activities. This analysis is referred to as return on investment. The analysis compares cash flows to investments.

Investment in TAPS was an estimated $9,400 million in 1975 to 1977. The initial investment in Prudhoe Bay was an estimated $3,700 million.[20] Over time, this investment was increased as a result of infield drilling, the waterflood project and the gas miscible fluid project. The estimated total accumulated investment in Prudhoe Bay is $8,700 million. As of 1987, the investment in Kuparuk is estimated to total $4.3 billion. This includes a portion of the waterflood project which was being installed in 1987 - 1988. The investment is Milne Point was

[20]Some of these expenditures were made as early as 1969. However, more precise dates are not available for these outlays. If the $900 million in 1969 lease bonuses is accounted for as a 1969 outlay, the rate of return (assuming no debt) drops to 28.1%. Alternatively, this analysis placed no value on the ANS properties for cash flows received after 1987. Assuming that these cash flows are worth $10 billion, the rate of return (assuming no debt) increases to 31.1%. Similary adjustments would be required to the returns assuming debt.

$575 million. Lisburne had an estimated investment cost of $1,000 million and Endicott an estimated project cost of $1,000 million. A summary of the estimated investments in the ANS is given in Table V-2. These amounts are based on estimates in Arco's and Sohio's annual reports and compared to other estimates.

Table V-2
Investment Schedule
(millions of dollars)

Year	*Prudhoe*	*TAPS*	*Other ANS*	*Total*
1987	$ 720		$1,900	$2,620
1986			1,000	1,000
1985	720			720
1984			570	570
1983	2,000			2,000
1982				0
1981	1,100		3,400	4,500
1980	250			250
1979	250			250
1978				0
1977	1,850	4,700		6,550
1976	1,850	4,700		6,550

Assuming 100% equity investment, cash returns on these investments would be equal to the reported profit numbers plus depreciation and interest. This is based on the fact that if one invested 100% equity, one would incur no interest costs. Column 1 of Table V-3 shows the production profit from Table III-5. Column 2 of Table V-3 is the depreciation on production. Column 3 is the sum of profit plus depreciation. Column 4 is the interest costs. Adding the profit plus depreciation from column 3 and the interest from column 4 gives the "all-equity cash flows" from production shown in column 5 of Table V-3.

The same process was followed for TAPS which yields the data in the fifth column of Table V-4.

Table V-3
Production Cash Flows
(millions of dollars)

Year	Profit	Deprec-iation	Profit plus Deprec.	Interest	Profit, Deprec. & Interest	Explor-ation	Profit, Deprec. & Explor.
1987	$1,956	$1,394	$3,350	$192	$3,542	$288	3,638
1986	1,192	1,418	2,610	183	2,793	288	2,898
1985	3,413	1,123	4,536	183	4,719	514	5,050
1984	4,498	866	5,364	148	5,512	258	5,622
1983	3,841	779	4,620	150	4,770	818	5,438
1982	3,452	698	4,150	171	4,321	647	4,797
1981	3,610	540	4,150	18	4,168	419	4,569
1980	3,250	504	3,754	10	3,764	176	3,930
1979	3,161	345	3,506	167	3,673	174	3,680
1978	623	280	903	248	1,151	274	1,177
1977	425	53	478	177	655	25	503

Table V-4
TAPS Cash Flows
(millions of dollars)

Year	Profit	Depreciation	Profit & Deprec.	Interest	Profit, Deprec. & Interest
1987	$1,226	$ 299	$1,525	$ 150	$1,675
1986	1,768	310	2,078	440	2,518
1985	1,386	309	1,695	411	2,106
1984	1,686	431	2,117	570	2,687
1983	1,457	475	1,932	579	2,511
1982	1,250	467	1,717	648	2,365
1981	1,046	431	1,477	681	2,158
1980	949	503	1,452	720	2,172
1979	1,019	421	1,440	771	2,211
1978	570	355	925	846	1,771

The total all-equity cash flows are shown in Table V-5. The first column is the investment flow from Table V-2. The second column is the production cash flow plus interest and depreciation from Table V-3. The third column is the TAPS cash flow plus interest and depreciation from Table V-4. The last column is the sum of the production and TAPS cash flows minus the investment flows.

Table V-5
All-equity Cash Flows
(millions of dollars)

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

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

According to the Sohio annual report of 1978, approximately 75% of the investment was financed with debt. In this case, the investments in 1976 and 1977 as shown in Table V-2 would be $1,638 million net each year. This is 25% of the investment outflows in those years. The remainder would have been financed with debt. Interest expense would be incurred on this debt and the debt would have to be repaid. The cash flow data from columns 3 of Tables V-3 and V-4 is the profit plus depreciation. These cash flows include a deduction for interest expense. These cash flow numbers are shown in column 2 and 3 of Table V-6. Assuming that all of the cash flows were used to pay off the debt as quickly as possible, the loan repayment would have consumed all of the cash flows in 1978 through 1979 and all but $2,131 million in 1980. The net cash flows in each year are shown in column 4 of Table V-6.

Table V-6
Cash Flows with 25% Equity
(millions of dollars)

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

The rate of return implied from the stream of cash flows shown in Table V-6 is 43.7%.

REINVESTMENT RATIOS

A question of interest is the extent to which cash flows from Alaska oil and gas operations are reinvested in Alaska. Reinvestment is defined as investments in ANS projects subsequent to the initial investment in Prudhoe Bay and TAPS plus exploration costs. These amounts are shown in column 1 of Table V-7. The relevant cash flows for reinvestment analysis are the production cash flows plus exploration costs and the cash flows from TAPS. Interest costs are deducted in determining these cash flows. The production amounts are shown in the last column of Table V-3. The production cash flows are shown in column 2 of Table V-7 and the TAPS cash flows are shown in column 3 of Table V-7. The total cash flows are shown in column 4 of Table V-7. The last column of Table V-7 is the ratio of reinvestment to the cash flows.

Table V-7
Reinvestment Ratios
(millions of dollars)

Year	*Re-investment*	*----Cash Flows----* *Production*	*TAPS*	*Total*	*Reinvestment Ratio*
1987	$2,908	$3,638	$1,525	$5,163	56.32%
1986	1,288	2,898	2,078	4,976	25.88%
1985	1,234	5,050	1,695	6,745	18.30%
1984	828	5,622	2,117	7,739	10.70%
1983	2,818	5,438	1,932	7,370	38.24%
1982	647	4,797	1,717	6,514	9.93%
1981	4,919	4,569	1,477	6,046	81.36%
1980	426	3,930	1,452	5,382	7.92%
1979	424	3,680	1,440	5,120	8.28%
1978	274	1,177	925	2,102	13.04%
Totals	**$15,766**			**$57,157**	

The data from Table V-7 indicate that the ANS producers are reinvesting approximately 27.8% of their cash flows in Alaska.

Appendix A
Sohio's 1982 Annual Report Disclosure

Supplementary Information on Oil and Gas Exploration, Development and Production Activities

This section provides information required by Statement of Financial Accounting Standards No. 69 (FASB 69), "Disclosures about Oil and Gas Producing Activities," which was issued in November 1982. FASB 69 aims to establish a comprehensive set of disclosures for oil and gas producing activities that replaces disclosures formerly required by either the Financial Accounting Standards Board (FASB) or the Securities and Exchange Commission (SEC), or both.

Three general disclosure areas comprise the information in this section. The first area provides historical information about costs and revenues, including the Company's aggregate recorded investment in oil and gas properties, annual costs incurred and a separate statement of the results of operations for producing activities. The second area contains the Company's petroleum engineers' quantity estimates for proved oil and gas reserves and the major factors causing changes in these reserve estimates. The final area of disclosure represents our compliance with the FASB's requirement to assign a monetary value to proved reserve quantities and changes therein using a standardized formula.

The Company has provided additional commentary throughout this section that is important for a proper understanding of the nature of the data provided and its inherent limitations.

Historical Information

Millions of Dollars	1982			1981			1980		
	Total	Alaska	Lower 48 States	Total	Alaska	Lower 48 States	Total	Alaska	Lower 48 States
Capitalized Costs as of December 31									
Proved properties	$6,318	$4,182	$1,037	$3,648	$3,387	$ 461	$2,905	$2,684	$321
Unproved properties	1,296	600	[illegible]	825	136	690	499	93	406
	8,614	4,782	[illegible]	4,873	3,523	1,150	3,404	2,877	727
Accumulated depreciation, depletion and amortization	1,747	1,309	838	1,320	966	354	986	717	269
	$4,767	$3,873	$1,164	$3,553	$2,557	$ 796	$2,418	$2,160	$458
Costs Incurred (capitalized or expensed)									
Acquisition of properties	$ 626	$ 420	$ 206	$ 383	$ –	$ 383	$ 190	$ 2	$188
Exploration	418	84	332	363	98	265	144	30	114
Development	1,146	804	342	856	802	61	368	364	32

Results of Operations for Producing Activities

The following summarizes the "Results of Operations for Producing Activities" as defined by FASB 69, for the years ended December 31, 1982, 1981 and 1980. As required, financing costs are not included in this statement. Income taxes are included in the results, but were computed under FASB guidelines using statutory tax rates, while considering the effects of permanent differences and tax credits relating to oil and gas producing activities.

Millions of Dollars	1982			1981			1980		
	Total	Alaska	Lower 48 States	Total	Alaska	Lower 48 States	Total	Alaska	Lower 48 States
Revenues	$6,457	$6,139	$ 268	$6,342	$6,116	$ 276	$4,496	$4,315	$181
Production costs	1,801	1,685	116	2,679	2,550	129	1,247	1,181	66
Depreciation and depletion	324	276	48	289	272	17	206	270	16
Exploration expenses									
Geological and geophysical	126	33	93	107	22	85	37	2	35
Amortization of unproved properties	163	7	156	78	8	70	64	16	53
Dry hole costs	84	6	90	124	14	110	40	13	27
Other	104	11	93	63	4	59	31	8	23
	477	57	434	370	46	324	176	38	138
	2,613	2,017	596	3,338	2,868	470	1,778	1,489	213
Income before interest and income taxes	3,794	3,122	[328]	3,004	3,248	[194]	2,718	2,826	[381]
Income taxes	1,362	1,822	[160]	1,629	1,770	[91]	1,566	1,574	[118]
	$1,432	$1,800	$ [168]	$1,375	$1,478	$ [103]	$1,232	$1,252	$ [20]

Appendix B
Barclay's de Zoete Wedd Prudhoe Bay Model (1988)

PROFITABILITY MODEL FOR PRUDHOE BAY FIELD

($/barrel)	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Alaskan Crude Price*	26.48	14.07	17.37	14.01	14.50	15.23	15.99	16.79	17.62	18.51	21.28
Less:											
Tanker Freight+	(3.24)	(2.71)	(2.60)	(2.70)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)
TAPS charge	(5.31)	(4.50)	(3.93)	(3.11)	(2.60)	(2.25)	(2.25)	(2.45)	(2.65)	(2.90)	(3.15)
Pipeline Loss	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)
Value at Pump Station One	17.83	6.76	10.74	8.10	8.80	9.88	10.64	11.24	11.87	12.51	15.03
Severance Tax	(2.59)	(0.68)	(1.29)	(0.97)	(1.06)	(1.19)	(1.28)	(1.35)	(1.42)	(1.50)	(1.80)
Field Operating Costs	(1.00)	(0.90)	(0.90)	(0.90)	(0.95)	(0.95)	(1.00)	(1.05)	(1.10)	(1.15)	(1.20)
Field Overheads	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.25)	(0.25)	(0.25)	(0.30)	(0.30)	(0.30)
Depreciation & Depletion	(1.60)	(2.00)	(2.00)	(2.10)	(2.20)	(2.20)	(2.30)	(2.40)	(2.40)	(2.45)	(2.45)
Ad Valorem Tax	(0.30)	(0.30)	(0.30)	(0.30)	(0.31)	(0.32)	(0.34)	(0.35)	(0.36)	(0.38)	(0.39)
Pre-tax Earnings Per Barrel	12.14	2.48	6.05	3.63	4.08	4.97	5.47	5.84	6.23	6.73	8.38
Operating Profit ($m)	3015	617	1539	934	1058	1269	1278	1257	1262	1277	1621

NOTES:

* *The Alaskan crude price is a weighted averaged of the prices received for sales on the West and Gulf Coasts; Gulf Coast sales normally fetch around $1/barrel more than those on the West Coast. We assume 1/3 of sales are made on the West Coast with the balance on the Gulf.*

\+ *Tanker freight is again a weighted average of the rate for deliveries from Valdez to the West and Gulf Coasts. Because shipping costs to the Gulf Coast are normally some $2.40/barrel higher, sales on the West Coast are more profitable to BP despite the fact that the crude oil commands a lower price than on the Gulf (see Section 5 below). In 1989 we have assumed that tanker costs rise by around 50c/barrel due to an increase in the use of expensive to operate Jones Act vessels (see Section 5), partly offset by a 70,000 barrel/day increase in shipments by pipeline from the West to Gulf Coasts (which is some 60c/barrel cheaper than transport by ship via Panama).*

Appendix C
Salomon Brothers' Arco Alaska Profits Model (1987)

Figure 5. Atlantic Richfield Company — Actual and Projected Alaskan Production Earnings, 1988-92E
(Dollars Per Barrel Unless Otherwise Indicated)

	1988	1989	1990E	1991E	1992E	1993E	1994E	1995E
Prudhoe Bay Field								
Selling Price — West Texas Intermediate Crude	$20.00	$15.75	$17.50	$20.00	$22.00	$24.00	$25.00	$26.00
Prudhoe Bay Field Crude Price[a]	14.00	11.20	12.90	14.75	16.25	17.75	18.50	19.25
Transportation Deductions								
Valdez to U.S. Gulf Coast	$4.90	$3.80	$3.85	$4.10	$4.25	$4.40	$4.50	$4.60
TransAlaska Pipeline Charge	3.28	4.75	3.90	3.50	3.25	3.00	3.00	3.00
Equals Prudhoe Bay Field Wellhead Price	$5.82	$3.65	$5.15	$7.15	$8.75	$10.35	$11.00	$11.65
Production Expenses								
Severance Tax	$1.30	$1.50	$1.50	$1.58	$1.88	$2.13	$2.25	$2.38
Windfall Profit Tax	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Field Operating Expenses	0.90	0.75	0.80	0.85	0.90	0.95	0.95	1.00
Depreciation and Depletion	1.60	1.75	1.80	1.85	1.90	1.95	2.00	2.05
Unit Operating Profit	$2.15	$2.65	$5.05	$7.42	$9.09	$10.72	$11.45	$12.09
Prudhoe Net Production (mb/d)	308.5	307.1	307.0	308.0	308.0	285.0	266.0	245.0
Prudhoe Operating Profit (Dollars in Millions)	$1,388	$297	$566	$834	$1,022	$1,116	$1,112	$1,081
Kuparuk River Field								
Kuparuk River Field Crude Price in U.S. Gulf	$20.60	$15.05	$16.70	$19.10	$21.00	$22.00	$23.00	$24.05
Transportation Deductions								
Valdez to U.S. Gulf Coast	$4.50	$3.80	$3.85	$4.10	$4.25	$4.40	$4.50	$4.60
TransAlaska Pipeline Charge	3.28	4.75	3.90	3.50	3.25	3.00	3.00	3.00
Kuparuk River Spur Line Charge	0.87	0.85	0.85	0.65	0.65	0.85	0.85	0.85
Equals Kuparuk Field Wellhead Price	11.15	5.65	8.30	10.85	12.85	14.05	15.75	16.60
Production Expenses								
Severance Tax	$1.30	$0.45	$0.85	$0.85	$1.05	$1.20	$1.25	$1.35
Field Operating Expenses	2.50	1.85	1.85	1.80	1.85	1.90	1.95	2.00
Depreciation and Depletion	3.75	3.55	3.55	3.65	3.75	3.85	3.90	4.00
Unit Operating Profit	$3.60	$0.20	$2.45	$4.55	$6.20	$7.90	$8.65	$9.25
Kuparuk Net Production (mb/d)	94.9	109.9	110.0	110.0	110.0	110.0	110.0	110.0
Kuparuk Operating Profit (Dollars in Millions)	$298	$8	$98	$183	$249	$317	$347	$371
Lisburne Formation								
Lisburne Formation Crude Price in U.S. Gulf[a,b]		$14.95	$16.65	$19.00	$20.90	$22.80	$23.75	$24.70
Transportation Deductions								
Valdez to U.S. Gulf Coast		$3.80	$3.85	$4.10	$4.25	$4.40	$4.50	$4.60
TransAlaska Pipeline Charge		4.75	3.90	3.50	3.25	3.00	3.00	3.00
Equals Lisburne Wellhead Price		6.40	8.90	11.40	13.40	15.40	16.25	17.10
Production Expenses								
Severance Tax		$0.64	$0.90	$1.15	$1.35	$1.55	$1.65	$1.70
Field Operating Expenses		2.70	2.75	2.75	2.85	2.90	3.00	3.10
Depreciation and Depletion		6.00	6.00	6.00	6.00	6.00	6.00	6.00
Unit Operating Profit		$(2.94)	$(0.75)	$1.50	$3.20	$4.95	$5.60	$6.30
Lisburne Net Production (mb/d)		4.1	15.0	20.0	30.0	35.0	40.0	40.0
Lisburne Operating Profit (Dollars in Millions)		$(4)	$(41)	$11	$35	$63	$82	$92
Total Alaskan Operating Profits Before Exploration Expenses (Dollars in Millions)	$1,686	$301	$660	$1,028	$1,306	$1,496	$1,541	$1,544
MEMO: Net Alaskan Crude Oil Production (mb/d)	403.4	421.3	432.0	438.0	448.0	430.0	410.0	395.0

[a] Assumed prices of Prudhoe Bay, Kuparuk River and Lisburne field oil production tied to the forecast prices of West Texas intermediate grade oil, based on the historical relationships of those crude prices to the WTI crude prices.
[b] Lisburne production began in the fourth quarter of 1988.
Mb/d: Thousands barrels per day. E: Estimate.

Appendix D

Alaska Oil Industry Development Time Line

1954 - BLM issues 272 oil and gas leases.

1957 - Swanson River oil discovered.

1962 - Cook Inlet oil discovered (Middle Ground Shoals)

1965 - Three additional Cook Inlet oil fields discovered (Granite Point, McArthur River, Trading Bay)

1967 - Prudhoe Bay oil is discovered. With over 10 billion barrels of reserves, it is a "super-giant" and the largest oil field in North America.

- Middle Ground Shoals, Granite Point and Trading Bay begin production.

1969 - Prudhoe Bay lease sale.

- Kuparuk River oil discovered. With a billion barrels of reserves it is a "giant" and is second only to Prudhoe Bay as the most productive field in the United States and Canada.

1977 - Prudhoe Bay oil Begins flowing to Valdez through Trans-Alaska Pipeline System (TAPS).

1978 - Endicott oil discovered.

1985 - Milne Point begins production.

1986 - Lisburne begins production.

- Kuparuk production peaks at 300,000 barrels per day.

1987 - Endicott begins production.

- Milne Point shuts down.

Appendix E

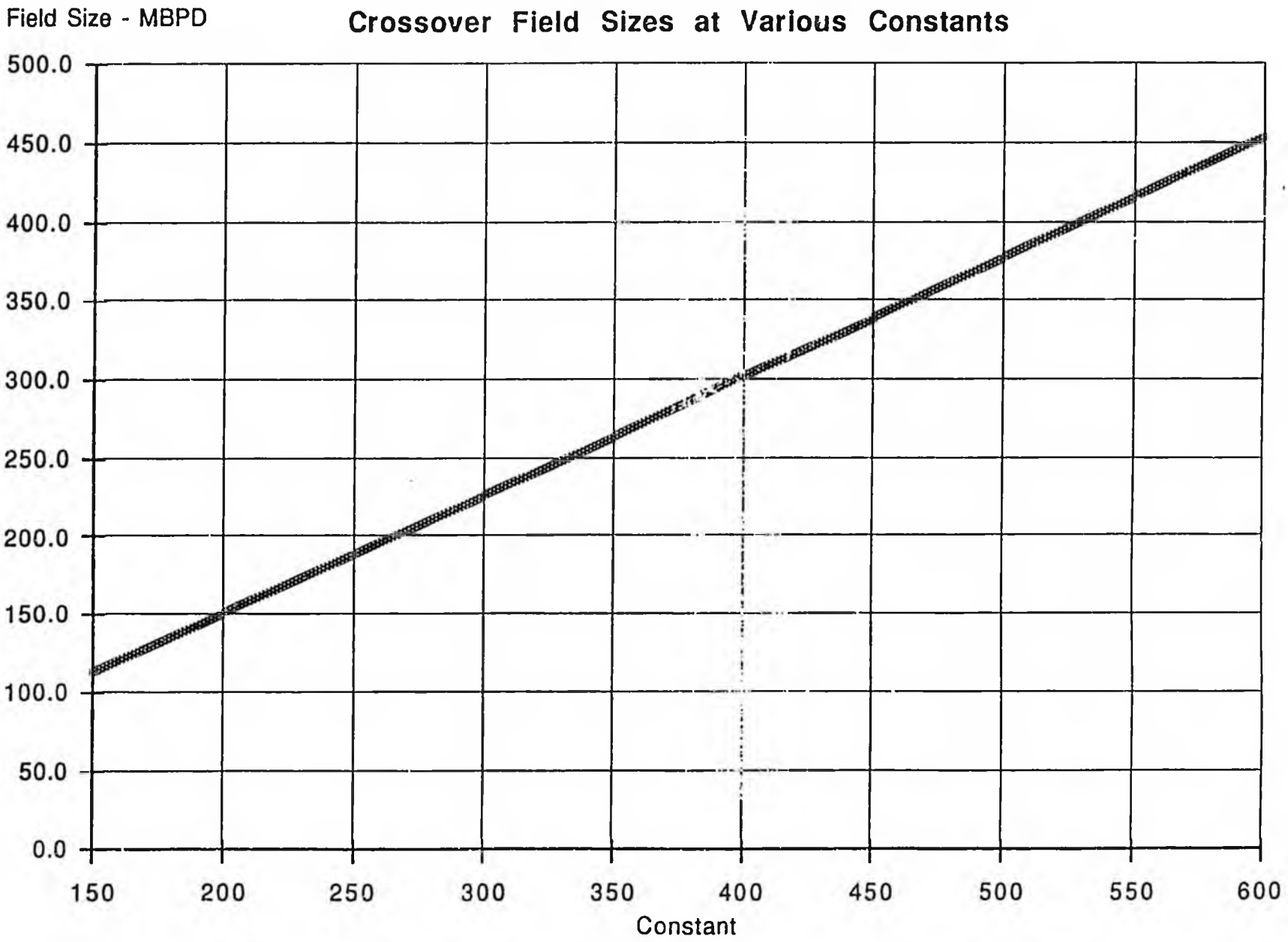
Total ANS Production and TAPS Profits
1977 through 1987
(millions of dollars)

1982 - 1987

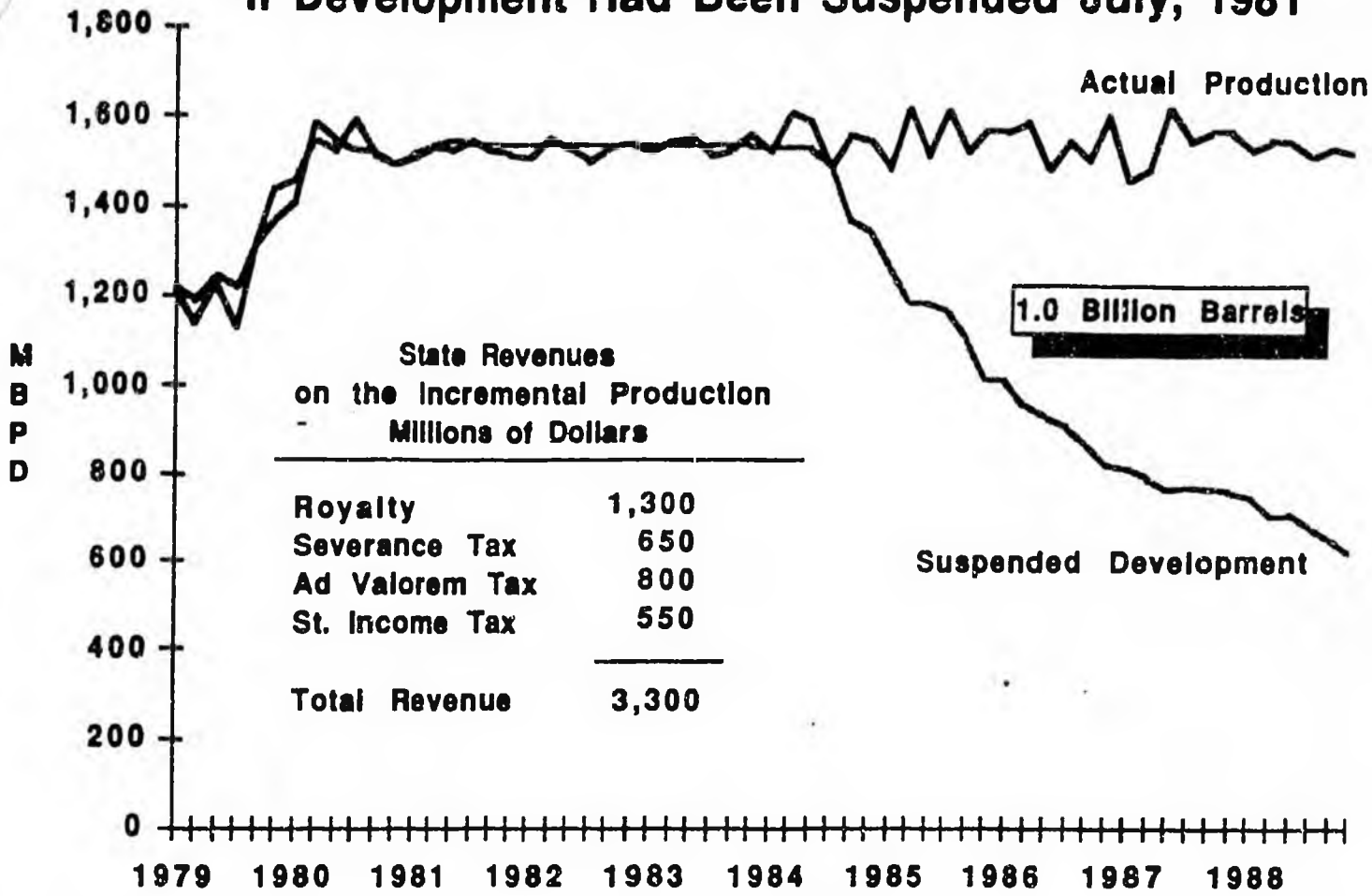
	1987	*1986*	*1985*	*1984*	*1983*	*1982*
Revenue	10393	8051	14707	14790	14685	15758
Expenses:						
Depreciation	1636	1674	1386	1258	1219	1131
Operating Expenses	1169	967	907	1065	954	1080
Overhead	129	124	164	100	104	84
Interest	328	611	585	709	719	807
Royalty	900	587	1316	1291	1283	1413
Severance Taxes	872	623	1403	1395	1388	1536
Property Taxes	341	353	353	339	329	329
State Income Taxes	150	94	257	253	248	239
Windfall Profit Taxes			39	211	426	1375
Federal Income Taxes	1653	0	3443	2170	2532	3031
Profits	**3215**	**3018**	**4854**	**5999**	**5483**	**4733**
Profit ($ per barrel)	**5.45**	**5.23**	**8.54**	**11.27**	**10.43**	**9.14**

1977 - 1981

	1981	*1980*	*1979*	*1978*	*1977*
Revenue	16935	13095	8855	4243	717
Expenses:					
Depreciation	941	979	741	609	38
Operating Expenses	1020	617	514	538	46
Overhead	51	15	2	0	2
Interest	698	730	927	1049	117
Royalty	1596	1143	706	221	86
Severance Taxes	1291	924	622	195	76
Property Taxes	317	314	297	278	30
State Income Taxes	872	712	486	127	30
Windfall Profit Taxes	3089	797			
Federal Income Taxes	2570	2703	512	17	32
Profits	**4490**	**4161**	**4048**	**1209**	**260**
Profit ($ per barrel)	**9.24**	**8.56**	**9.88**	**3.47**	**2.58**


Field Size - MBPD
Crossover Field Sizes at Various Constants
500.0
450.0
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
150
200
250
300
350
400
450
500
550
600
Constant

Prudhoe Bay Production
If Development Had Been Suspended July, 1981



State Revenues
on the Incremental Production
Millions of Dollars

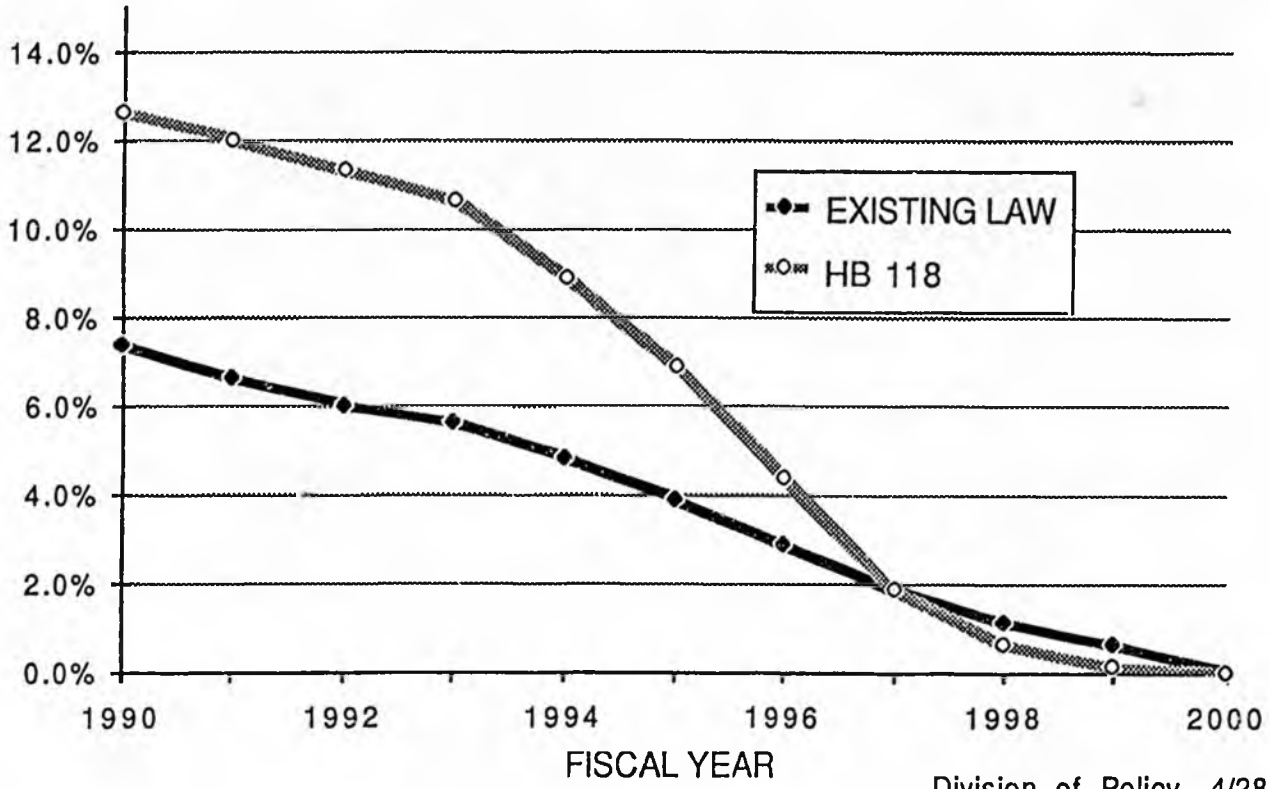
Royalty	1,300
Severance Tax	650
Ad Valorem Tax	800
St. Income Tax	550
Total Revenue	3,300

Prudhoe Bay
1981-1988 Industry Investment

		$ MM
Additional Wells		2,550
Producing Wells	450	
Injection Wells	123	
Other Wells	23	
Waterflood		2,099
Production Facilities		1,475
Gas Handling		470
Enhanced Oil Recovery		620
Other		820
Total		$8,040

Figure 2

PROJECTED TAX RATES AT KUPARUK



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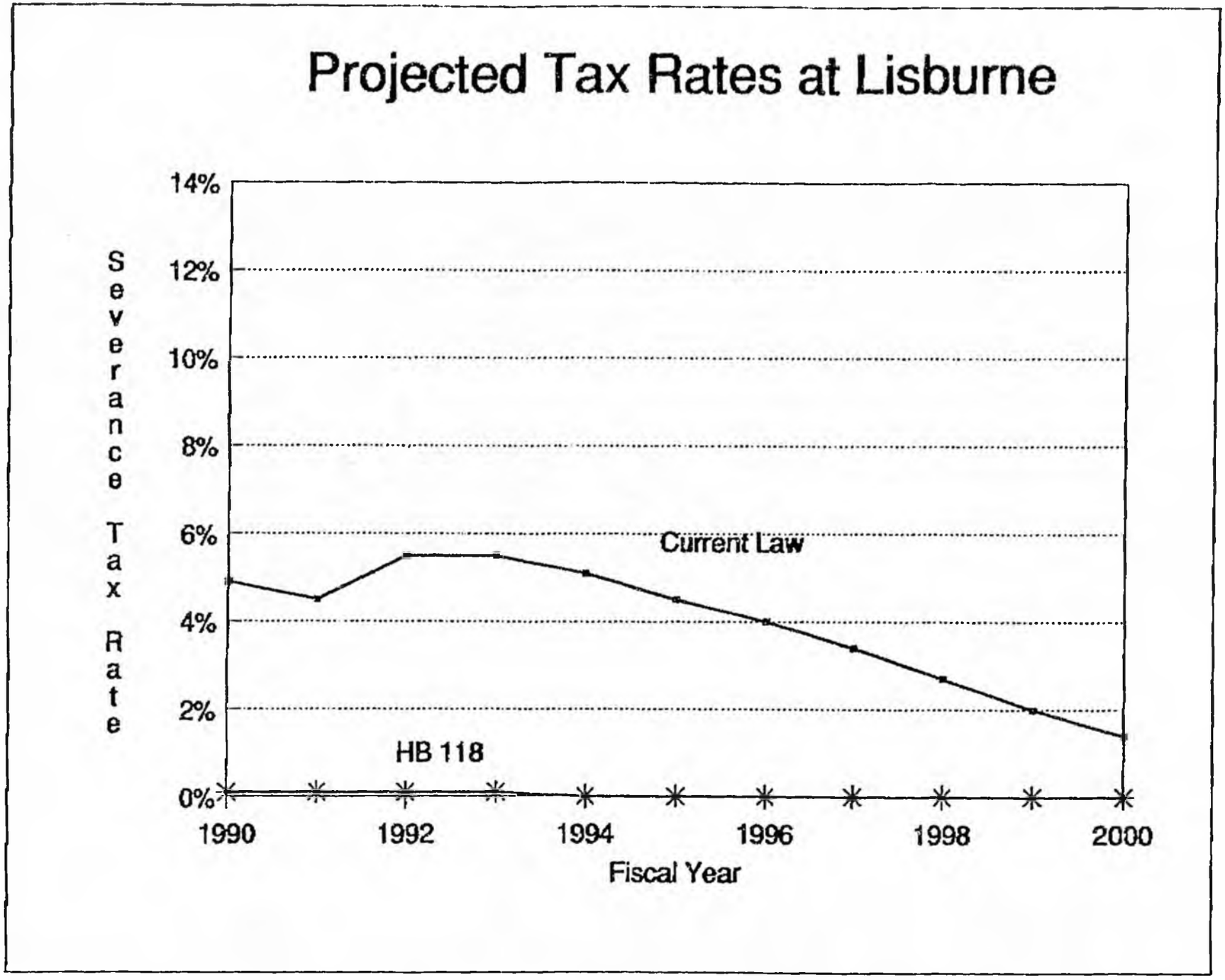
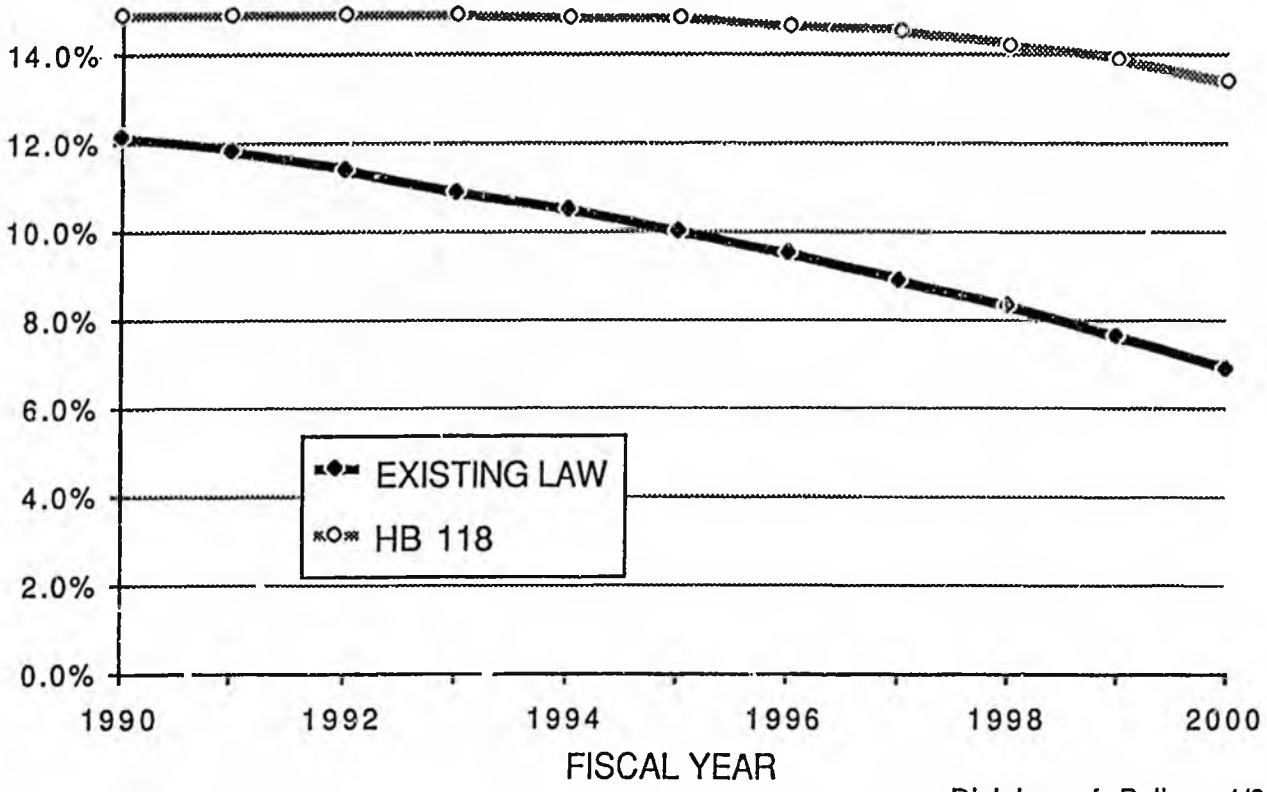


Figure 1

PROJECTED TAX RATES AT PRUDHOE BAY



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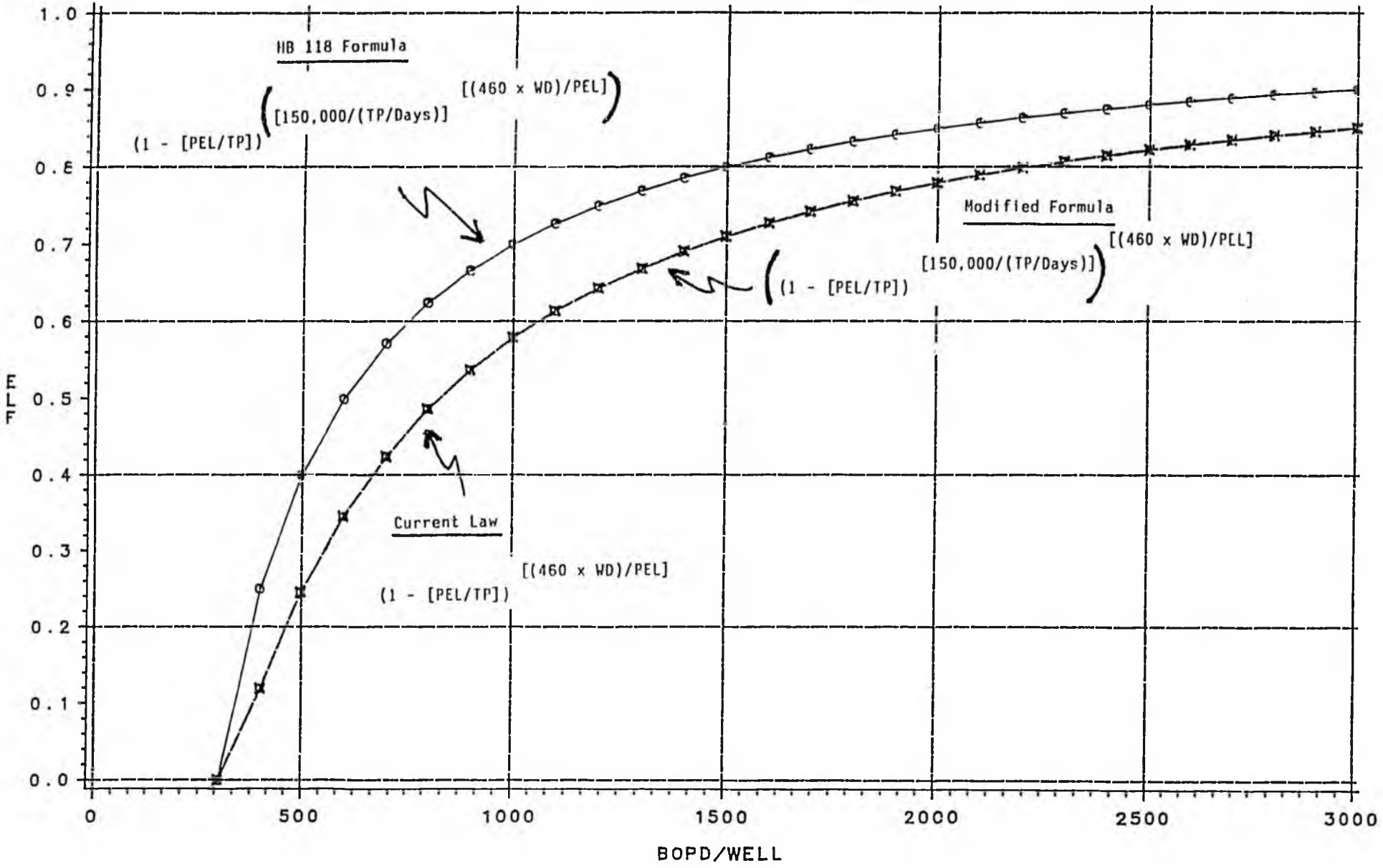
HB 118 – ELF FORMULA SENSITIVITIES

150,000 BOPD FIELD

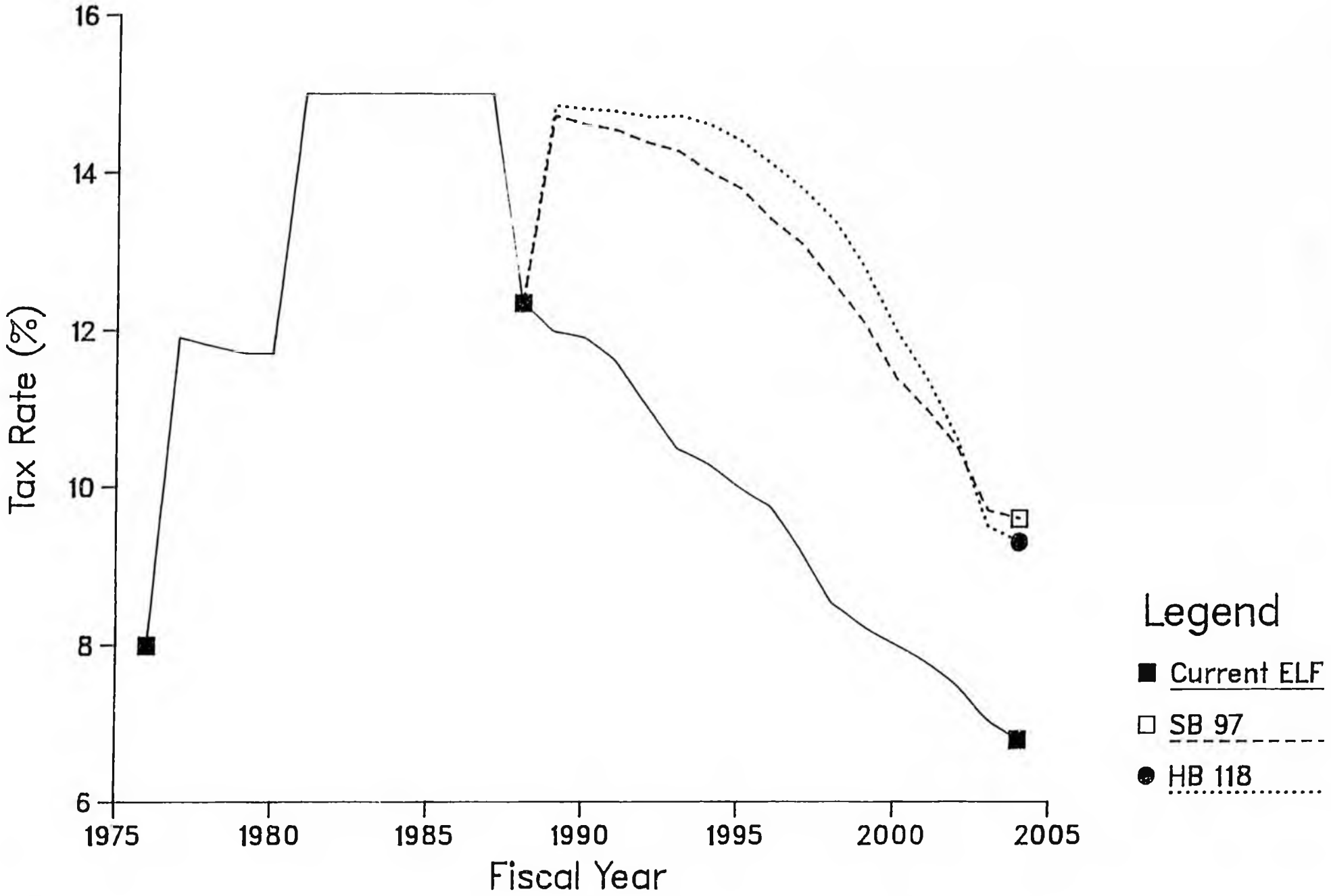


X X X X X CURRENT TAX
o o o o oHB118 FORMULA
¤ ¤ ¤ ¤ ¤MOD FORMULA

HOUSE FINANCE COMMITTEE
03-16-89
B.V. LIDDELL

PBU Historical and Projected Tax Rate

Includes SB 97 and HB 118 Impacts



B. V. Liddell
4-23-89

INCREMENTAL SEVERANCE TAX EXAMPLE 20-Apr-89

KUPARUK EXAMPLE

THE ADDITION OF 1 WELL PRODUCING AT THE AVERAGE RATE

ACTUAL DEC'88 FIGURES

	CURRENT LAW		HB-118	
	BASE	+1 WELL	BASE	+1 WELL
PRODUCTION MBPD	307.2	308.1	307.2	308.1
TOTAL PRODUCTION MBL/MO	9,522.37	9,552.27	9,522.37	9,552.27
WELLS	318	319	318	319
BBL/DAY/WL	965	965	965	965
ELF	0.564894	0.564894	0.883291	0.883817
EFFECTIVE TAX RATE	8.4734%	8.4734%	13.2494%	13.2573%
TOTAL FIELD TAX M$	4,165.46	4,178.55	6,513.28	6,537.63
TOTAL FIELD TAX $/BBL	0.500	0.500	0.782	0.782
INCREASE IN TAX $M		13.08		24.35
INCREASE IN MBBLS		26.17		26.17
INCREMENTAL SEVERANCE TAX $/BBL		0.500		0.930

ARCO Kuparuk Example

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

[illegible] of Price, [illegible]

CURRENT LAW

Field Rate x Wellhead Price x Severance Tax x ELF

90,168,000 BOPY x $/BBO x 0.15 x 0.85134

= $63,461,000/year

Addition of 1 well:

90,277,000 BOPY x $/BBO x 0.15 x 0.8504

=$63,433,305/year

A decrease of $37,846 year

PROPOSED LAW

Field Rate x Wellhead Price x Severance Tax x ELF

90,168,000 BOPY x $/BBO x 0.15 x 0.7500

=$58,88,273/year

Addition of 1 well:

90,277,000 BOPY x $/BBO x 0.15 x 0.7238

=$58,578,464/year

An increase of $58,611 year

[Copy of ARCO Handout, March 27, 1987]

"a $38,000 tax break for the oil industry, is that a good thing for Alaska ?"

The Administration says, No.

For the citizens of Alaska, as Royalty Owners, the answer is definitely , Yes !

The Rest of the Story on the ARCO Drilling Example

	Without Royalty	Including Royalty	Royalty
Original Kuparuk bbl / Yr.	90,168,000	103,049,143	12,881,143
With New Well	90,277,000	103,173,714	12,896,714
		Additional Royalty	15,571
		x $9.00 / bbl	$140,143
		+ Ad Valorem Tax	$20,000
		- ELF Impact	($37,846)
		Total State Revenue Impact	**$122,297**

Kuparuk River Field	Net Pay Feet	Gross Reserves MMBL
Kuparuk Maximums	70-80	60.9
Current Kuparuk Developed Area Average	55	42.7
Remaining Drill Site Development Areas		
Drill Site 1 K	25	8.9
Drill Site 1 M	10	12.8
Drill Site 1 J	25	6.2
Drill Site 2 K	20	22.6
Drill Site 2 M	25	32.3
Drill Site 2 L	15	21.5
Drill Site 2 P	15	11.8
Drill Site 3 G	15	22.7
Drill Site 3 R	25	13.2
Drill Site 3 L	25	15.7
Total		167.6
Average		16.8

PROJECT PORTFOLIO

KUPARUK

Project	Description	Timing
Drilling		
• Peripheral Drillsite 2K	Selective peripheral DS development	1989 SU
• Peripheral Drillsite 3R	on 160 acre spacing. Total of 98	1989 SU
• Peripheral Drillsite 2M	additional wells	1990 SU
• Peripheral Drillsite 2L		1990 SU
• Peripheral Drillsite 3G		1990 SU
• Rem. Peripheral Dev.	14 drillsite expansions, 6 new drillsites, 180 additional wells 1 rig 1989, 2 rigs thereafter	1990===>
Waterflood/EOR		
• LIP-3 Expansion	Additional water handling capacity @ CPF-3	1990 SL
• Infill Drill @ DS 1Y/2Z	22 new wells. Improve EOR efficiency	1989===>
• Infill Drill @ DS 1A	16 wells. Seed for Phase I infill	1989 SU
• Phase I Infill Drilling	160 + 80 acre accelerate reserves	1991 SU
• Fullfield EOR	19 drillsites staged over 4 years	1991 SU

ANS Net Revenue

	Kuparuk $/bbl	Kuparuk $/bbl	Kuparuk $/bbl
Assumed Crude Price	**13.42**	**16.41**	**18.96**
Tanker Freight	2.70	2.70	2.70
Quality Differential	0.40	0.40	0.40
TAPS Tariff	3.11	3.11	3.11
Kuparuk Pipeline	0.70	0.70	0.70
Pipeline Loss	0.10	0.10	0.10
Wellhead Price	6.41	9.40	11.95
Production Cost and Capital Recovery	5.43	5.43	5.43
Total Net Revenue	0.99	3.98	6.53
State Royalty	0.75	1.12	1.44
Severance Tax	0.50	0.73	0.92
Property Tax	0.44	0.44	0.44
State Income Tax	-0.02	0.05	0.11
Total State	1.66	2.34	2.91
Federal Income Tax	-0.23	0.56	1.23
Producer Profit	-0.45	1.08	2.38

Source:
Barclays de Zoete Wedd, September 1988
Alaska Department of Revenue October 1988
State of Alaska Royalty and Severance Methodology

ANS Net Revenue Under HB-118

	Kuparuk $/bbl	Kuparuk $/bbl	Kuparuk $/bbl
Assumed Crude Price	**13.42**	**16.41**	**18.96**
Tanker Freight	2.70	2.70	2.70
Quality Differential	0.40	0.40	0.40
TAPS Tariff	3.11	3.11	3.11
Kuparuk Pipeline	0.70	0.70	0.70
Pipeline Loss	0.10	0.10	0.10
Wellhead Price	6.41	9.40	11.95
Production Cost and Capital Recovery	5.43	5.43	5.43
Total Net Revenue	0.99	3.98	6.53
State Royalty	0.75	1.12	1.44
Severance Tax	0.75	1.10	1.40
Property Tax	0.44	0.44	0.44
State Income Tax	-0.03	0.04	0.10
Total State	1.91	2.70	3.37
Federal Income Tax	-0.31	0.43	1.07
Producer Profit	-0.61	0.84	2.08

Source:
Barclays de Zoete Wedd, Septer
Alaska Department of Revenue I
State of Alaska Royalty and Seve

3.50 - Capital recovery
2.00 production cost.

SB 97 and HB 118 ELFs COMPARED

An analysis prepared for the
Senate Special Committee on Oil and Gas
20 April 1989

As the chair requested, this analysis focuses on three fields -- Prudhoe, Kuparuk and Lisburne -- and the differences between SB 97 and HB 118.

ELF formulas in both SB 97 and HB 118 have two variables: productivity per well, and total productivity (or, field productivity). In the real world these variables are closely interrelated; both are subject to continuous change over the life of an oil field. Figure 1 illustrates what realistically will happen when the two variables are considered together. Figure 2 illustrates what happens if total production is hypothetically held constant and per-well productivity is varied. Figure 3 hypothetically holds per-well productivity constant for the three fields, and illustrates the severance tax rates that would result when the total production is varied. The declining tax rates illustrated in Figure 1 are depicted graphically in Figures 4-6.

Figure 7 shows the declining total production and per-well productivity projected for the three fields, and which underly the rates in Table 1.

As requested, step-by-step instructions for calculating the ELFs under the two bills are included following Figure 7.

Division of Policy and Department of Revenue.

The Economic Limit Factor or ELF is a fraction which reduces severance taxes as well productivity declines.

EFFECTIVE SEVERANCE TAX RATE equals nominal severance tax rate times ELF.

For example, 15.00% times 0.824 equals an effective severance tax rate of 12.36%.

Department of Revenue (April 20, 1989)

Figure 1

PROJECTED SEVERANCE TAX RATES, FY 1990-2000
UNDER EXISTING LAW, SB 97, AND HB 118

Fiscal Year	PRUDHOE			KUPARUK			LISBURNE		
	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118
1990	12.1%	14.7%	14.9%	7.4%	11.1%	12.6%	5.4%	1.3%	0.4%
1991	12.0%	14.7%	14.9%	6.6%	10.4%	12.0%	4.7%	0.7%	0.1%
1992	11.8%	14.6%	14.9%	6.0%	9.6%	11.3%	5.7%	0.9%	0.2%
1993	11.4%	14.5%	14.9%	5.6%	8.9%	10.6%	5.7%	0.9%	0.2%
1994	11.1%	14.4%	14.8%	4.8%	7.3%	8.9%	5.4%	0.6%	0.1%
1995	10.5%	14.2%	14.8%	3.9%	5.5%	6.9%	4.4%	0.2%	0.0%
1996	9.7%	14.0%	14.6%	2.9%	3.6%	4.4%	4.0%	0.1%	0.0%
1997	8.9%	13.6%	14.5%	1.9%	1.7%	1.9%	3.5%	0.0%	0.0%
1998	7.9%	13.2%	14.2%	1.1%	0.6%	0.6%	2.9%	0.0%	0.0%
1999	6.8%	12.6%	13.9%	0.6%	0.2%	0.1%	1.3%	0.0%	0.0%
2000	5.6%	11.9%	13.4%	0.0%	0.0%	0.0%	1.4%	0.0%	0.0%

Division of Policy, 4/19/89

Figure 2

HYPOTHETICAL SEVERANCE TAX RATES RESULTING WHEN FIELD PRODUCTION IS HELD CONSTANT AND AVERAGE DAILY PRODUCTION PER WELL IS VARIED--UNDER EXISTING LAW, SB 97, AND HB 118

(Approximate FY 90 averages shown in highlighting.)

Average Daily Production Per Well	PRUDHOE 1,452,100 barrels per day			KUPARUK 279,500 barrels per day			LISBURNE 43,800 barrels per day		
	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118
300	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
325	0.3%	10.9%	13.9%	0.3%	2.8%	5.6%	0.2%	0.0%	0.0%
350	0.8%	11.7%	14.1%	0.8%	4.2%	7.1%	0.6%	0.0%	0.0%
375	1.3%	12.2%	14.3%	1.3%	5.2%	8.1%	1.0%	0.0%	0.0%
400	1.8%	12.6%	14.4%	1.8%	6.0%	8.8%	1.5%	0.0%	0.0%
500	3.7%	13.4%	14.6%	3.7%	8.2%	10.5%	3.0%	0.3%	0.0%
600	5.2%	13.7%	14.7%	5.2%	9.5%	11.5%	4.2%	0.7%	0.1%
700	6.4%	14.0%	14.7%	6.4%	10.4%	12.1%	5.2%	1.2%	0.3%
800	7.3%	14.1%	14.8%	7.3%	11.0%	12.5%	6.0%	1.7%	0.6%
900	8.1%	14.3%	14.8%	8.1%	11.5%	12.8%	6.6%	2.2%	0.8%
1,000	8.7%	14.3%	14.8%	8.7%	11.9%	13.1%	7.1%	2.8%	1.2%
1,100	9.2%	14.4%	14.9%	9.2%	12.2%	13.3%	7.5%	3.2%	1.5%
1,200	9.6%	14.5%	14.9%	9.6%	12.4%	13.4%	7.9%	3.7%	1.8%
1,300	10.0%	14.5%	14.9%	10.0%	12.6%	13.6%	8.2%	4.1%	2.2%
1,400	10.4%	14.6%	14.9%	10.4%	12.8%	13.7%	8.5%	4.5%	2.5%
1,500	10.7%	14.6%	14.9%	10.7%	13.0%	13.8%	8.7%	4.8%	2.8%
1,600	10.9%	14.6%	14.9%	10.9%	13.1%	13.8%	8.9%	5.1%	3.1%
1,700	11.1%	14.6%	14.9%	11.1%	13.2%	13.9%	9.1%	5.4%	3.4%
1,800	11.3%	14.7%	14.9%	11.3%	13.3%	14.0%	9.3%	5.7%	3.7%
1,900	11.5%	14.7%	14.9%	11.5%	13.4%	14.0%	9.4%	6.0%	3.9%
2,000	11.7%	14.7%	14.9%	11.7%	13.5%	14.1%	9.5%	6.2%	4.2%
2,100	11.8%	14.7%	14.9%	11.8%	13.6%	14.1%	9.7%	6.4%	4.4%
2,200	12.0%	14.7%	14.9%	12.0%	13.6%	14.2%	9.8%	6.6%	4.7%
2,300	12.1%	14.7%	14.9%	12.1%	13.7%	14.2%	9.9%	6.8%	4.9%
2,400	12.2%	14.7%	14.9%	12.2%	13.7%	14.2%	10.0%	7.0%	5.1%

Division of Policy, 4/19/89

Figure 3

HYPOTHETICAL SEVERANCE TAX RATES RESULTING WHEN PER-WELL PRODUCTIVITY IS HELD CONSTANT AND AVERAGE DAILY PRODUCTION PER FIELD IS VARIED--UNDER EXISTING LAW, SB 97, AND HB 118

(Approximate FY 90 averages shown in highlighting.)

Average Daily Production for the Field	PRUDHOE 2,290 barrels per well per day			KUPARUK 817 barrels per well per day			LISBURNE 730 barrels per well per day		
	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118
10,000	12.1%	1.1%	0.0%	7.4%	0.0%	0.0%	5.4%	0.0%	0.0%
20,000	12.1%	4.1%	0.7%	7.4%	0.2%	0.0%	5.4%	0.1%	0.0%
30,000	12.1%	6.4%	2.9%	7.4%	0.9%	0.1%	5.4%	0.5%	0.0%
40,000	12.1%	7.9%	5.2%	7.4%	1.8%	0.5%	5.4%	1.1%	0.2%
50,000	12.1%	9.0%	7.0%	7.4%	2.8%	1.3%	5.4%	1.8%	0.7%
60,000	12.1%	9.8%	8.5%	7.4%	3.7%	2.3%	5.4%	2.4%	1.4%
70,000	12.1%	10.4%	9.5%	7.4%	4.5%	3.4%	5.4%	3.1%	2.2%
80,000	12.1%	10.9%	10.4%	7.4%	5.3%	4.5%	5.4%	3.6%	3.1%
90,000	12.1%	11.3%	11.0%	7.4%	5.9%	5.5%	5.4%	4.2%	3.8%
100,000	12.1%	11.6%	11.5%	7.4%	6.5%	6.4%	5.4%	4.6%	4.6%
200,000	12.1%	13.2%	13.7%	7.4%	9.9%	11.2%	5.4%	7.5%	8.7%
300,000	12.1%	13.8%	14.3%	7.4%	11.3%	12.8%	5.4%	8.9%	10.2%
400,000	12.1%	14.1%	14.5%	7.4%	12.2%	13.5%	5.4%	9.6%	10.9%
500,000	12.1%	14.2%	14.7%	7.4%	12.7%	14.0%	5.4%	10.1%	11.3%
600,000	12.1%	14.4%	14.8%	7.4%	13.0%	14.2%	5.4%	10.4%	11.5%
700,000	12.1%	14.5%	14.8%	7.4%	13.3%	14.4%	5.4%	10.7%	11.7%
800,000	12.1%	14.5%	14.8%	7.4%	13.5%	14.5%	5.4%	10.9%	11.8%
900,000	12.1%	14.6%	14.9%	7.4%	13.7%	14.6%	5.4%	11.0%	11.8%
1,000,000	12.1%	14.6%	14.9%	7.4%	13.8%	14.6%	5.4%	11.1%	11.9%
1,100,000	12.1%	14.7%	14.9%	7.4%	13.9%	14.7%	5.4%	11.2%	11.9%
1,200,000	12.1%	14.7%	14.9%	7.4%	14.0%	14.7%	5.4%	11.3%	12.0%
1,300,000	12.1%	14.7%	14.9%	7.4%	14.1%	14.8%	5.4%	11.4%	12.0%
1,400,000	12.1%	14.7%	14.9%	7.4%	14.1%	14.8%	5.4%	11.4%	12.0%
1,500,000	12.1%	14.7%	14.9%	7.4%	14.2%	14.8%	5.4%	11.5%	12.1%
1,600,000	12.1%	14.8%	14.9%	7.4%	14.2%	14.8%	5.4%	11.5%	12.1%

Division of Policy, 4/19/89.

Figure 4

PROJECTED TAX RATES AT PRUDHOE BAY

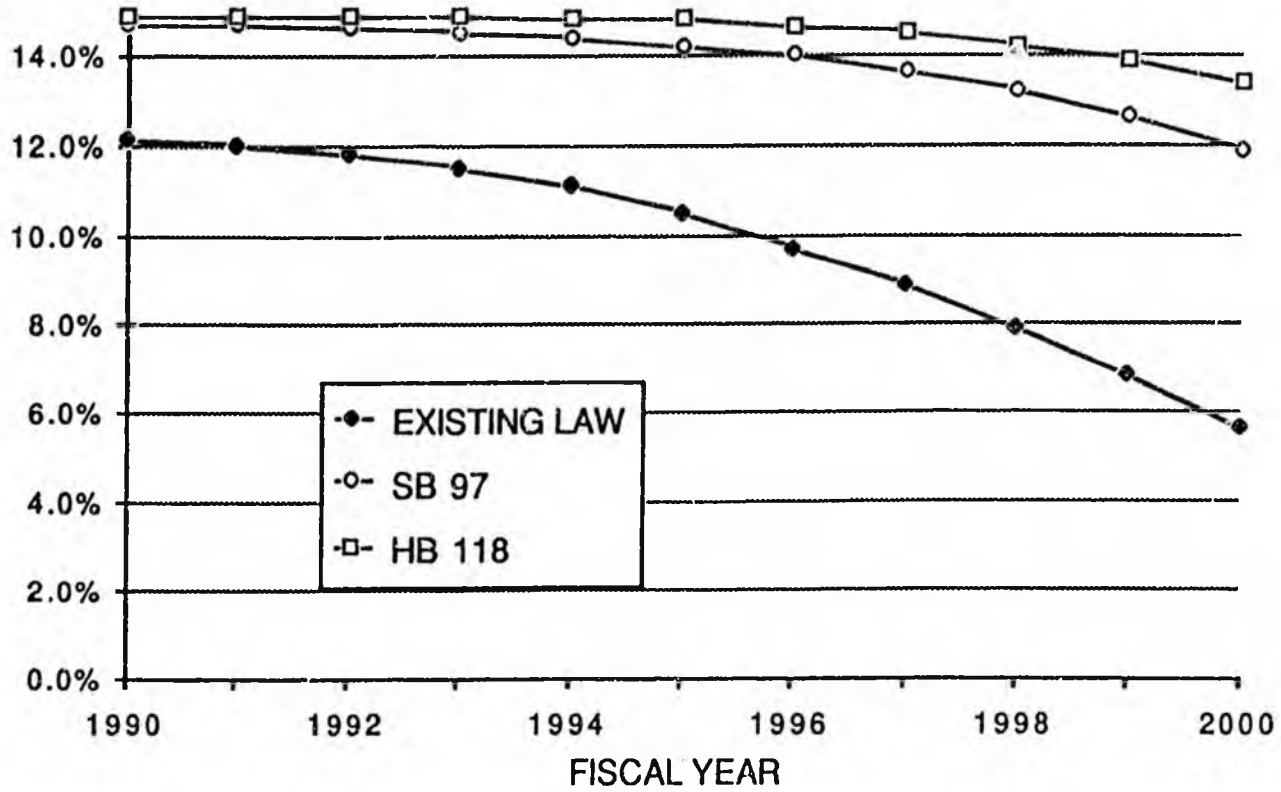


Figure 5

PROJECTED TAX RATES AT KUPARUK

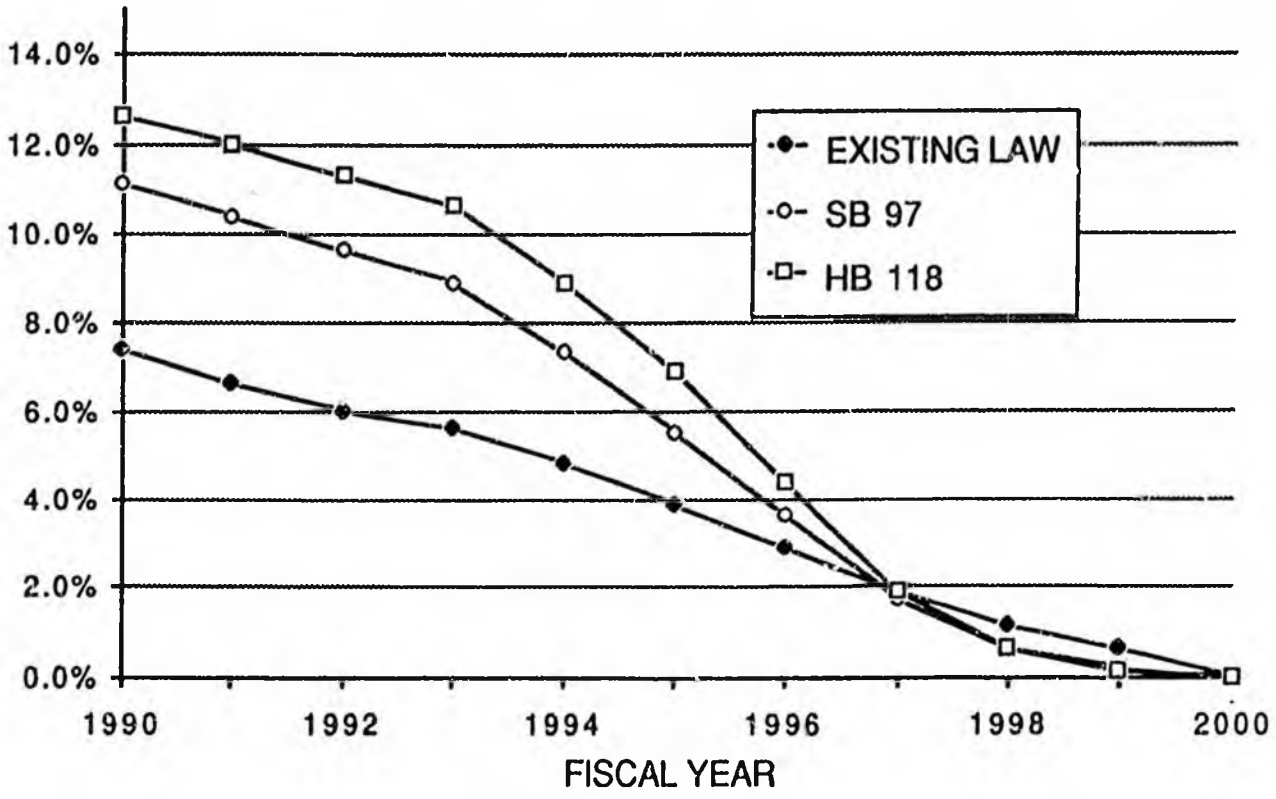


Figure 6

PROJECTED TAX RATES AT LISBURNE

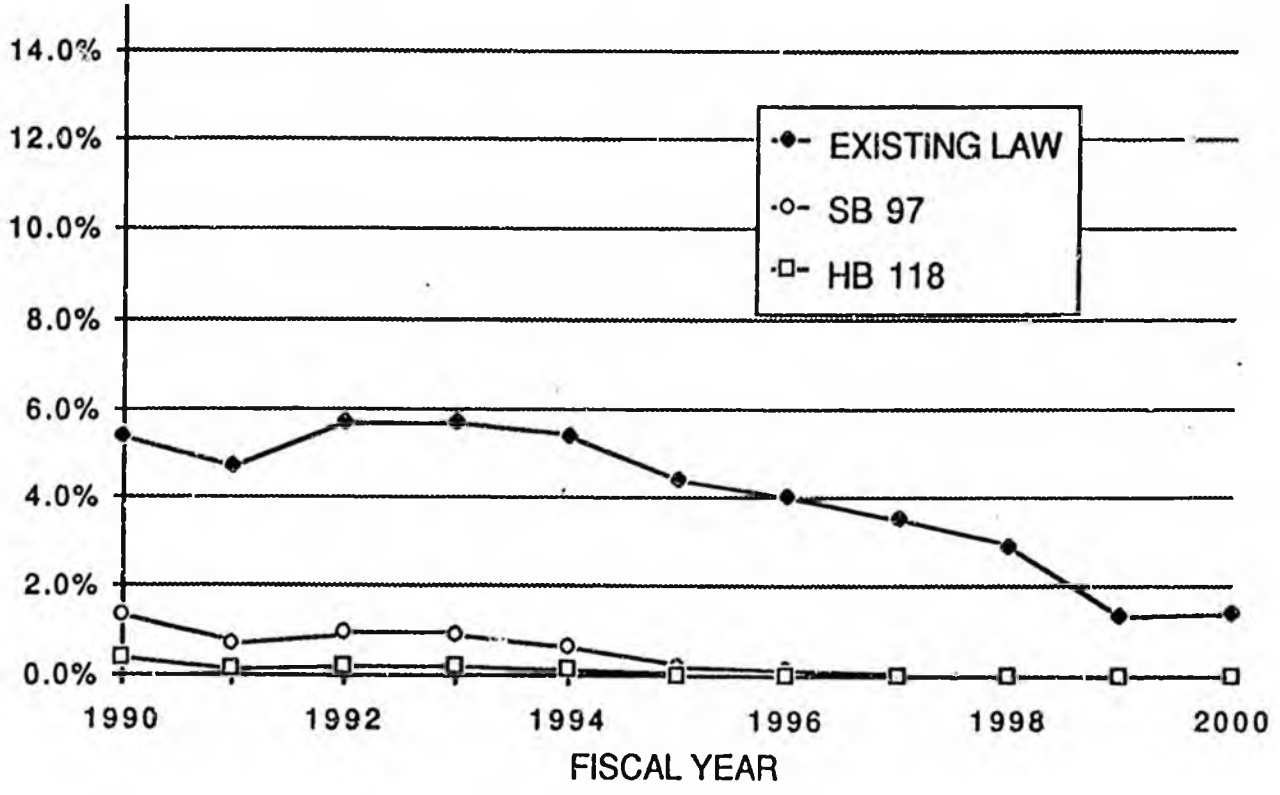


Figure 7
Estimated Production and Well Productivity
Prudhoe Bay, Kuparuk, Lisburne

	Prudhoe Bay		Kuparuk		Lisburne	
	Volume (mmbbl/yr)	Avg p/well Prod (bbl/day)	Volume (mmbbl/yr)	Avg p/well Prod (bbl/day)	Volume (mmbbl/yr)	Avg p/well Prod (bbl/day)
1990	530	2290	102	817	16	731
1991	504	2080	97	724	15	642
1992	472	1845	89	666	15	642
1993	427	1614	81	536	15	642
1994	387	1450	69	569	14	619
1995	332	1303	59	513	12	548
1996	282	1165	50	457	11	520
1997	239	1039	42	404	10	489
1998	203	930	36	365	9	457
1999	173	834	32	341	7	376
2000	147	753	26	294	7	376

Based on the Dept of Revenue's Spring 1989 forecast. Well productivity is adjusted for well days.

COMPUTING THE SB 97 ELF

(Using typical Prudhoe Bay field values in the examples.)

The SB 97 Economic Limit Factor formula is:

ELF = (1-PEL/TP)EXP[(55,000,000*WD)/(PEL*TP/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 * 634 wells * 30 days = 5,706,000 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:
*634 wells * 30 days * 2290 barrels per well = 43,555,800 barrels of production per month.*

EXP (Exponent) -- Means that the expression following is an exponent.

WD (Well Days) =
(average number of operating wells during the month)*
(number of days of production for the month).
For example:
*634 wells * 30 days = 19020 well days.*

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

CALCULATION EXAMPLE

=(1- PEL / TP) EXP[(55,000,000* WD)/(PEL * TP / Days)]

=[1 -(5,706,000/43,555,800)]EXP[(55,000,000*19,020)/(5,706,000*43,555,800/30)]

= (1 - .1310) EXP (.1263)

= $(.8690)^{(.1263)}$

= .9824

COMPUTING THE HB 118 ELF

(Using typical Prudhoe Bay field values in the examples.)

The HB 118 Economic Limit Factor formula is:

ELF = (1-[PEL/TP])EXP([150,000/(TP/Days)] EXP [(460*WD)/PEL])

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 * 634 wells * 30 days = 5,706,000 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:
*634 wells * 30 days * 2290 barrels per well = 43,555,800 barrels of production per month.*

EXP (Exponent) -- Means that the expression following is an exponent.

WD (Well Days) =
(average number of operating wells during the month)*
(number of days of production for the month).
For example:
*634 wells * 30 days = 19,020 well days.*

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

CALCULATION EXAMPLE

= (1-[PEL/TP])EXP([150,000/(TP/Days)] EXP [(460*WD)/PEL])

=[1 -(5,706,000/43,555,800)]EXP[(150,000/(43,555,800 /30)] EXP [(460* 19,020)/ 5,706,000])

$= (1 - .1310)\ EXP\ .1033^{1.5333}$

$= .8690^{.0308}$

= .9957

MEMORANDUM

State of Alaska
Office of the Governor
Division of Policy

TO: The Hon. Alyce Hanley DATE: April 20, 1989

FROM: Gregg Erickson

SUBJECT: Corporate Profits Earned Alaska

During the March hearings on the ELF legislation in the House you requested information on the net income earned by the fishing industry.

Based on tax data from the Department of Revenue, we estimate that 1987 taxable corporate net income in Alaska totaled $2.010 billion. Of this, $24 million (1.2 percent) was earned by corporations in fishing or fishing related fields.

Based on Dept. of Revenue data, we estimate taxable oil company income at $1.681 billion, or 84 percent of the total.

Taxable income may differ substantially from the income shown on a company's books of account. This is especially true under the special taxation arrangements adopted for the oil industry by Alaska in 1981. The recent study by Professor Deakin found that 1987 oil industry net income totaled $3.182 billion. Based on the Deakin analysis, it is likely that the oil industry accounts for more than 90 percent of total book income attributable to Alaska. The figure cannot be determined precisely, however, because comparable figures for non-petroleum book income are not available for the state.

cc: Senate Special Oil and Gas Committee

PROFITABILITY OF OIL AND GAS PRODUCTION ALASKA VERSUS FOREIGN COUNTRIES 1983–87

Thomas Horst
Horst & Associates
March 13, 1989

Introduction

The ultimate objective of this Report is to compare the royalty and tax burden of oil and gas operations in Alaska with that in foreign countries. In our search for information on how the total income from oil and gas production was shared between producers and governments, we undertook a comprehensive investigation of data published by the World Bank and other international agencies, the U.S. government, domestic and foreign trade publications, academic studies, and the companies' annual reports. In the end, we could identify only one reliable comprehensive source of data describing companies' actual oil and gas production: the supplemental information U.S. oil and gas producers are required by Financial Accounting Standard No. 69 ("FAS 69") to disclose in their annual financial reports. Although FAS 69 does not require companies to disclose total royalties, taxes or other payments to various governments per se, it does require companies to report their revenues, expenses (including income taxes), and a bottom-line result of operations by major geographic area of operations. Accordingly, we tabulated the results of foreign oil and gas producing activities for 1983-87 for the ten largest U.S. producers and compared those results to the comparable results reported by BP America and Sohio, the only U.S. company that reports separately the results of its Alaska operations.

FAS 69 Disclosure Requirements

Before describing those results, we should summarize the disclosure required by FAS 69. Broadly speaking FAS 69 requires companies to disclose information pertaining to: (1) proved oil and gas reserves, (2) capitalized costs relating to oil and gas producing activities, (3) costs incurred for property acquisition, exploration and development activities, (4) results of operations, and (5) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Domestic and foreign producing activities must be disclosed separately, and individual countries or groups of countries must be disclosed separately if appropriate for meaningful disclosure.

In disclosing their results of operations, oil and gas producers are required to report information on their (1) revenues, (2) production (lifting) costs, (3) exploration expenses, (4) depreciation, depletion, and amortization, and valuation provisions, (5) income tax expense, and (6) and the result of operations, which generally equals the excess of revenues over the

various expenses.[1] Royalty payments and net profit disbursements are excluded from gross revenues. Production or severance taxes are not excluded from gross revenues, but are instead included in production costs.

Neither corporate overhead nor interest expense is included in production costs or otherwise deducted in calculating the results of operations. Moreover, income taxes are calculated using the statutory income tax rate applied to revenues less production (lifting costs), exploration expenses, depreciation, depletion, and amortization, and valuation provisions, but not corporate overhead or interest expense. Calculation of income tax expenses reflects permanent differences between book and taxable income (e.g., the excess of percentage depletion over cost depletion) and tax credits and allowances (e.g., the investment credit), but not book-tax timing differences (e.g., book depreciation versus accelerated tax depreciation, or the expensing of intangible drilling and development costs for tax, but not for book, purposes). Because book-tax timing differences usually result in a portion of book income tax expense being deferred until a later period, and because

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[1] The reported results of operations would also be reduced by the after-tax income attributable to minority interests in consolidated subsidiaries. Because the revenue and expenses include amounts attributed to minority interests are not reported separately, the after-tax income amounts shown in the tables of this Report are before deduction of after-tax income attributable to minority interests in the consolidated subsidiaries. Moreover, we have not included amounts attributable to interests of the reporting company in non-consolidated entities (e.g., Aramco).

no account is taken of the deductions for corporate overheads and interest expense, the amount of income tax expense recorded under the FAS 69 disclosure will generally overstate the amount of income tax actually paid on account of oil and gas production. What effect this overstatement of income tax has had on the comparison of the results of foreign oil and gas operations to the results of Alaska oil and gas operations is uncertain because income tax expense has potentially been overstated in both instances.

Results of Foreign Oil and Gas Operations for 10 Largest U.S. Producers, 1983-87

The results of foreign oil and gas operations for the 10 largest U.S. producers are described in detail in Appendix I and are summarized in Table 1 on the following page. Because results for a particular producer vary widely from region to region and may vary from year to year for a particular region, we have shown on the following page the five-year (1982-87) cumulative results for all foreign operations of each of the 10 producers. Exxon is not only the largest U.S.-based foreign producers, but also the most profitable with after-tax income averaging 21.4 percent of total oil and gas revenues. At the other extreme was Shell, which consistently reported losses on its limited foreign operations. (Obviously, these results do not include the very substantial and presumably profitable non-U.S. operations of Shell's U.K. and Dutch parent corporation or its foreign sister subsidiaries.)

TABLE 1: RESULTS OF FOREIGN PRODUCTION
10 LARGEST U.S. COMPANIES, 1983-87

Company	Years	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Amoco	1983-87	18,866	7,088	3,879	3,209	17.0%
ARCO	1983-87	2,789	357	330	27	1.0%
Chevron	1983-87	14,391	8,748	6,548	2,200	15.3%
Exxon	1983-87	42,198	20,696	11,673	9,023	21.4%
Mobil	1983-87	25,153	14,301	9,836	4,465	17.8%
Occidental	1983-87	8,561	3,391	3,012	379	4.4%
Phillips	1983-87	8,140	4,450	3,848	602	7.4%
Shell	1983-87	711	(77)	54	(131)	-18.4%
Tenneco	1983-87	1,033	236	137	99	9.6%
Texaco	1983-87	16,469	9,269	7,110	2,159	13.1%
10 Companies	1987	24,472	10,653	5,998	4,655	19.0%
10 Companies	1986	20,053	7,549	4,711	2,836	14.2%
10 Companies	1985	33,867	18,041	12,986	5,055	14.9%
10 Companies	1984	32,808	18,165	12,705	5,460	16.6%
10 Companies	1983	27,111	14,051	10,027	4,024	14.8%
10 Companies	1983-87	138,311	68,459	46,427	22,032	15.9%

One of the more striking features of the results shown in Table 1 is the clear correlation between the size of a U.S. company's foreign operations and its profitability (Exxon has the largest and most profitable, Mobil the second largest and second most profitable, etc.). Whether this correlation reflects economies of scale, a tendency of older foreign operations (and longer established foreign operators) to be more profitable, or some other phenomenon has not been investigated.

Results of Alaska Oil and Gas Operations for BP America, 1986-87, and Sohio, 1983-85

The only major U.S. company that discloses separately the results of its Alaska oil and gas operations is BP America and its major predecessor corporation, Sohio.[2] The BP America/Sohio results for the 1983-87 period are summarized in Table 2. For the entire five-year period, BP America and Sohio reported after-tax income from Alaska oil and gas operations equal to 27.7 percent of Alaska revenues. This result is higher than the comparable 21.4 percent after-tax income margin reported by Exxon, the company with the most profitable foreign operations, and substantially above

[2] BP America was formed in 1987 when BP successfully acquired the remaining 45 percent of the outstanding shares in Sohio. BP America was the result of the merger of Sohio with BP North America, which held BP's Trans Alaska Pipeline System subsidiary, BP's minority interest in the Kuparuk field and associated pipeline, and other BP-owned U.S. assets.

TABLE 2: RESULTS OF ALASKA PRODUCTION
BP AMERICA 1986-87, SOHIO 1983-85

Company	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
BP America	1987	3,340	1,358	611	747	22.4%
BP America	1986	1,973	248	108	140	7.1%
Sohio	1985	4,433	2,571	1,241	1,330	30.0%
Sohio	1984	4,146	2,675	1,240	1,435	34.6%
Sohio	1983	4,013	2,336	1,037	1,299	32.4%
BP/Sohio	1983-87	17,905	9,188	4,237	4,951	27.7%

the 16.0 percent average margin for the foreign operations of the 10 largest producers taken together.

The annual results for BP America and Sohio shown in Table 2 indicates that for years through 1985 Sohio was consistently reporting after-tax income of 30 percent or more of its Alaska oil and gas revenues. The sharply lower after-tax income, 7.1 percent of Alaska oil and gas revenues, reported in 1986 was attributable primarily to the collapse of oil prices, but also to a series of unusual expenses recognized in that year. Specifically, BP America stated in the notes to its 1987 financial statements:

> During 1986 the Company recorded special charges of $1.13 billion pretax which have been classified as unusual items in the Statement of Income. The charges principally represented provisions for the restructuring of certain operations, the loss on the disposal of certain operations and the impairment of properties where future cash flows were no longer expected to recover current book values. Also included was a provision representing the excess of the Company's settlement with the Internal Revenue Service of the windfall profit tax valuation of Alaskan crude oil for the period 1980-83 over amounts previously provided.
>
> In addition to these unusual items, the exploration and production businesses recorded pretax charges of $410 million in 1986 for the impairment of leases held in oil and gas prospect inventory, over and above normal lease amortization expense. These charges were included in exploration expenses in the Statement of Income and resulted from technical reassessment and expected lower future oil prices.

The pattern of the BP America/Sohio results provide an interest contrast to that for foreign operations for U.S. companies. While both total revenues and after-tax income from foreign operations were down sharply in 1986 on account of the