

Oil Taxes General

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this report is the
conclusion of
examination for the



THE TAXATION OF THE PETROLEUM INDUSTRY
UNDER ALASKA'S CORPORATE INCOME TAX

A Report Prepared for the Alaska Legislature
and the Alaska Department of Revenue

By:

Jerome M. Zeifman

and

Kenneth G. Ainsworth

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Introduction

During the 1975 and 1976 sessions of the Tenth Alaska Legislature concern was expressed by many legislators as to the effectiveness of the present corporate income tax law with respect to the income of multi-jurisdictional corporations which do business in other states as well as in Alaska.

Briefly summarized, the present Alaska law applicable to multi-jurisdictional corporations operates as follows:

First: A determination is made of the corporation's entire taxable income from all sources. Since the Alaska law incorporates the Federal Internal Revenue code by reference, with certain modifications, the corporation's entire taxable income from all sources is largely the same amount of income that is taxed by the Federal Government.^{1/}

Second: To determine the percentage of entire income attributed to Alaska, the State has adopted the Uniform Division of Income for Tax Purposes Act. In addition, Alaska has become a member of the Multistate Tax Compact, an organization currently comprised of 21 states, each of which also has adopted the Uniform Act. Under the Uniform Act, Alaska taxable income is determined by multiplying the taxpayer's entire taxable income by a fraction which is the average of the ratios of Alaska-to-total "property", "payroll" and "sales".^{2/}

As a result of the concerns expressed in 1975 and 1976, serious policy questions have arisen with respect to two interrelated aspects of the present corporate tax system. On the one hand, questions arise as to the extent to which multi-jurisdictional corporations are currently able to offset their Alaska income by losses and other deductible items relating to activities outside of Alaska. On the other hand, questions also arise as to the effectiveness of the present statutory apportionment method used to determine the percentage of a multi-jurisdictional corporation's entire income attributed to Alaska for tax purposes.

In October, 1976, we were retained as consultants to the Alaska State Legislature and the Alaska State Department of Revenue. Since then, we have undertaken a coordinated legal and economic analysis of the present corporate income tax system as applied to the taxation of income from the production of non-renewable natural resources in general and petroleum in particular.

We have obtained information and data from the following sources: The Alaska Department of Revenue; the Multistate Tax Commission; the staff of the Joint Committee on Internal Revenue Taxation of the United States Congress; the Congressional Budget Office; the United States Department of Commerce; and the California Franchise Tax Board. Based on our analysis to date, we have made findings concerning both the current Alaska method for determining entire taxable income and the Alaska method for apportioning income. We have concluded that the present method is ineffective and embodies policies which the Alaska Legislature ought appropriately to re-evaluate.

As is discussed in greater detail in the body of our report, Alaska's use of the Federal corporate tax base has created an anomalous situation in which Alaska currently ~~provides a tax base for corporate taxpayers~~ ~~which is not designed to subsidize, and~~ ~~as well,~~

As is also discussed below, the present apportionment formula operates in such a way as to reduce the amount of taxable income attributable to Alaska by corporations which extract non-renewable petroleum resources from the State. This effect occurs largely because the Uniform Division of Income for Tax Purposes Act contains a "destination-oriented" sales factor, in which sales of Alaskan oil are generally assigned to Alaska only with respect to petroleum products which are ultimately consumed in the State. As a result, the exportation of petroleum from Alaska has the effect of reducing the tax liability of the extractor of the Alaska petroleum.

To provide for a more effective means of taxing the income of multi-jurisdictional petroleum companies, we have formulated legislative recommendations which are summarized below in Section A of our report.

Sections B and C of the report include our analysis of the present tax base and apportionment formula, as well as discussions of alternative recommendations.

As is set forth in Section D, the enactment of the proposed legislation would increase Alaska's annual income tax revenues from the petroleum industry by about 400 per cent of whatever amount can be realized under the present law.

Additional considerations relating to our recommendations are set forth in Sections E, F, and G.

A. SUMMARY OF LEGISLATIVE RECOMMENDATIONS

1. Outline of Proposed Bill

A privilege (franchise) tax would be imposed on corporations engaged in the extraction, refining or transportation of petroleum in Alaska.

The tax would be measured by the Corporation's "book income" of Federal taxable income, whichever is higher. "Book income" would be determined without regard to taxes on or measured by income.

Corporations engaged in business both within Alaska and within other states or foreign countries would be required to apportion their income according to a three factor formula based on the ratios of Alaska-to-total: [REDACTED] and [REDACTED]

The property and payroll factors of the formula would be similar to the property and payroll factors in the Uniform Division of Income for Tax Proposed Act, which is currently in effect in Alaska.

[REDACTED]

[REDACTED]

Affiliated corporations engaged in unitary businesses would be required to file combined reports.

2. Some Policy Considerations Concerning the Structure of the Proposed Bill.

(a) Taxable Event

The [REDACTED] taxation [REDACTED] is conventional among the states and is partially modeled after the so-called "double barreled" income tax structure of states such as California, Idaho, Minnesota, Oregon, Pennsylvania and Utah.^{3/}

Under the Supreme Court's decision in the Colonial Pipelines case,^{4/} Alaska can impose such a privilege tax on corporations which do not intra-state business but are engaged exclusively in interstate commerce.

In effect, the tax can be structured so that no corporation would have a lower tax liability than would be possible under the present direct tax on corporate net income.

The privilege tax feature would tend to strengthen the State's position in court cases involving apportionment disputes. It could have special significance in enabling Alaska to tax income relating to economic activities on the outer continental shelf which might otherwise be exempt from the present direct tax.

(b) Corporations Subject to Tax

The determination of the corporations subject to the privilege tax would involve a simple computation based on gross income. The test might simply be whether more than 50 percent of the corporation's "ordinary gross income" is derived from the extraction, transportation, refining, processing developing or marketing of petroleum or petroleum related products. Such a test would substantially limit the imposition of the privilege tax to vertically integrated multi-national corporations. However, it might also be desirable to provide a test which specifically excludes from the scope of the privilege tax any corporation which has a total gross income of less than a specified dollar amount, such as \$250 million.^{5/}

(c) Tax Base

~~_____ income included in~~
~~_____ to taxes~~

~~_____~~ Since the corporations included within the scope of the tax are generally publically held, their annual reports to shareholders are currently required to be certified by independent Certified Public Accountants and are used for Federal regulatory purposes.

In the case of an affiliated group of corporations, the Commissioner should have the authority to prescribe whether the report between common parent corporation to its shareholders rather than the report of subsidiaries to the parent

will be taken into account for determination of the tax base.

It should be noted that the use of federal taxable income, if higher, an alternative base would probably occur only in very unusual cases involving the operation of Federal recapture provisions.

(d) A Possible Alternative to The Use of "Book Income"

Although the use of "book income" allows for both easy enforcement and the simple removal of tax subsidies from the tax base, it may be desirable to provide for an item-by-item upward adjustment of federal taxable income. This would restore only specific "erosions" from the Federal tax base.

If an item-by-item approach is taken, it might also be desirable to continue to allow tax subsidies and tax incentives, but only with respect to purely Alaskan activities.

(e) Apportionment Formula

The use of an origin-oriented ~~method~~ based on ~~the location of the taxpayer's business~~ would tend to maximize the effectiveness of Alaska's apportionment in the simplest and most efficient way.

(f) Combining of the Income of Affiliates

It is essential to the fundamental purposes of the proposed tax that separate accounting methods of reporting not be permitted in the case of any affiliated corporations engaged in unitary enterprises. It is also essential that multi-national corporations be required to apportion their income on a world-wide combined basis in the manner currently being advanced in Alaska and other states.

(g) Administrative Considerations

The proposed legislation would afford Alaska the advantages of continuing to participate in the joint audit program of the Multistate Tax Commission as well as the advantages of dealing effectively with problems which may be peculiar to Alaska.

B. ANALYSIS OF ALASKA'S CORPORATE
INCOME TAX BASE UNDER PRESENT LAW

The following analysis relates to Alaska's present method of determining a corporation's entire income from all sources. It should be clearly understood that in the case of a corporation doing business both within and without Alaska, the corporation's entire income will be subsequently subjected to apportionment, so that only a percentage will ultimately be attributed to Alaska for tax purposes. The present Alaska method of apportionment is analyzed in Section C of this report. Thus, this section of the report is limited to a discussion of Alaska's system for determining entire income from all sources.

1. Present Law

Under AS 43.20.021, the responsibility for determining Alaska's total corporate income tax base has largely been delegated by the State Legislature to the United States Congress. This is because provisions of the Federal Government's Internal Revenue code are incorporated by reference for purposes of Alaska's corporate income tax. In effect, the corporate taxpayer first determines the Federal taxable income and is then required simply to make a limited number of adjustments. These are as follows: Income taxes paid to Alaska and to other states and foreign countries are not allowed as a deduction; the foreign tax credit is not allowed; the exemptions relating to Domestic

International Sales Corporations provide under Section 991 of the Internal Revenue code are not allowed by Alaska; and the job development investment credit provided under Section 50 of the Internal Revenue code is limited for Alaska tax purposes to the first \$500,000 of qualified investment put into use for each taxable year.

Since Federal taxable income is used as a starting point for the computation of the Alaska tax base, any changes in the exemptions from tax or credits against tax made by the United States Congress would be reflected immediately in changes in Alaska revenues were it not for the recent adoption by the Alaska Legislature of CH 124, SLA 1976 which postpones the effective date of such changes for two years.

2. Federal Policies Currently Reflected in Alaska's Tax Law

On a Federal level there is now wide-spread agreement that the Internal Revenue code and the Federal tax system have not been structured simply as a means for raising Federal revenues. Instead, by creating special tax provisions, the United States Congress has seen fit to encourage or subsidize some types of economic activities and to discourage or frustrate others.

As has been pointed out in the recent "Report to the Senate and House Committee on the Budget" of the United

States Congress,^{6/} the encouragement or subsidy, as the case may be, takes the form of a reduced income tax liability. The amount of the reduction from the "normal" tax owed has come in recent years to be called a "tax expenditure". In theory, at least, the Government could have collected the full tax and used some part of it in some other way -- by a Federally administered grant or loan program, for example -- to encourage the same activity or help the same industry.

Thus, for example, Congress has sought to encourage the development of oil and gas by allowing write-offs through the expensing of exploration and development costs. The provision will mean an estimated annual revenue loss to the Federal Government of 1.8 billion dollars by 1981. That same money could be spent by Congress in other ways to stimulate activity in the oil and gas industries. Instead, Congress has decided to "expend" it in the form of tax reductions.

The concept of tax expenditures has been incorporated in the Congressional Budget Act of 1974, which requires the listing of present and proposed tax expenditures and a calculation of their revenue loss implications. In particular, Section 202(f)(1) requires the Director of the Congressional Budget Office to report annually on the "levels of tax expenditures under existing law."

The projected tax expenditures in the most recent report

of the Director of the Congressional Budget Office is relevant in assessing the extent to which Alaska, in following Federal definitions of taxable income is, in turn, providing tax incentives and tax subsidies to corporations subject to Alaska tax.

To assist in making such an assessment, we have prepared the following Table of some of the specific tax expenditure estimates made by the Congressional Budget Office. We have selected those items which are particularly helpful both because of their applicability to corporations generally, and to oil companies in particular.

TABLE I
SELECTED FEDERAL TAX EXPENDITURE ESTIMATES FOR CORPORATIONS
(Millions of dollars, fiscal years)

Function	1977	1978	1979	1980	1981
Expensing of exploration and development costs	840	1,045	1,285	1,540	1,850
Expensing of research and development expenditures	695	725	755	785	815
Capital gains: (Other than farming & timber)	900	1,015	1,090	1,170	1,260
Asset Depreciation Range (ADR)	1,630	1,825	2,000	2,095	2,135
Deferral of income of controlled foreign corporations	365	365	365	365	365
Deductibility of charitable contributions (social services)	352	402	446	489	536

In considering the above data, it is important to note that the tax incentives and tax subsidies granted to corporations by Congress are not limited in a geographical sense to activities that relate to particular States. For example, the provisions of the Internal Revenue code which allow petroleum companies to expense, rather than capitalize, intangible drilling costs have the effect of encouraging the corporation to engage in drilling activities in any state or foreign country in which it may choose to operate. Thus, if the corporation is doing business both within and without Alaska, the tax expenditures made by Congress can be used for non-Alaskan drilling.

In other words, since Alaska has simply adopted the relevant provisions of the Internal Revenue code, Alaska, in effect, offers the same type of tax incentives to develop non-Alaskan wells as Alaskan wells.

Obviously, the same type of effects are produced under the present law with respect to each of the tax expenditures listed in the above table. To give some specific examples: Alaska currently offers preferred tax treatment with respect to gains from the sale of capital assets located outside of Alaska; a corporation engaged in the development of mines outside of Alaska is currently allowed to reduce its Alaska tax by expensing rather than capitalizing the non-Alaskan mine development costs; contributions to non-profit charitable

organizations which do not operate in Alaska can be used to reduce Alaska income tax liability.

In considering the effects on Alaska income tax liability of the above items, it is also important to point out, that Alaska follows Federal policies with respect to net-operating loss carryovers. As a result, corporations which do not incur "normal" losses in an economic sense but simply have "tax losses" due to a super-abundance of deductions emanating from tax incentives and tax subsidies, are able to carry over such losses from one tax year to another. Thus, the coupling of the tax incentive and tax subsidy provisions of the Internal Revenue Code with the carryover provisions, allows the corporation with non-Alaskan "losses" the opportunity to use the non-Alaskan "loss" to reduce Alaska tax liability to the maximum extent possible over a five year period.

3. Revenue Losses to Alaska Due to the
Use of the Eroded Federal Tax Base

A meaningful perspective can be obtained concerning the effects of federal tax subsidies and federal tax incentives on Alaska revenues by a comparison that we have made concerning the difference between the federal taxable income reported by a selected sample of thirteen petroleum corporations and the so-called "book income" of the same corporations.

The following table (II) compares book values (before income taxes) with Federal taxable income as reported on the income tax form. The estimates of the differences between book value and Federal taxable income for ten of the thirteen sample corporations for which data was available, show that book values exceed taxable income values by 1.6 to 3.0 billions of dollars per year. This variation is not unexpected because not all of the returns in the sample have been fully audited, but more important for state tax policy, Federal taxable income reflects the changing national policies with respect to goals such as lowering the rate of unemployment, encouraging nationwide conservation of resources and nationwide investment in energy supply.

The differences between book income and Federal taxable income indicate that coordinating State taxable income with book income rather than Federal taxable income would have generated about 5 million dollars of additional Alaska taxable income in 1975.

See table on following page.

TABLE II

DIFFERENCE BETWEEN BOOK INCOME AND TAXABLE INCOME
FOR A SAMPLE OF OIL COMPANIES OPERATING IN ALASKA

<u>Company</u>	<u>Difference 1973 (thousands \$'s)</u>	<u>Difference 1974 (thousands \$'s)</u>	<u>Difference 1975 (thousands \$'s)</u>
A	NA	221,219	38,825
B	177,629	208,882	129,451
C	NA	NA	17,009
D	39,814	34,204	NA
E	166,769	242,587	150,231
F	193,072	368,175	110,248
G	NA	NA	464,781
H	335,080	448,695	608,333
I	84,495	93,351	NA
J	(61)	(333)	72
K	NA	46,338	(120,374)
L	261,888	280,454	NA
M	278,634	784,519	193,439
Total	1,834,298 (4 cases Not available)	3,056,434 (2 cases Not available)	1,592,015 (3 cases Not available)

4. Alternatives to the Use of Federal Taxable Income
as a Measure of the Alaska Corporate Tax Imposed
on Petroleum Corporations

Should the Alaska legislature wish to discontinue the present reliance on the "eroded" Federal tax base, several alternative approaches might be considered. [REDACTED]

[REDACTED]

[REDACTED] book income /

[REDACTED] on Federal

[REDACTED] created

[REDACTED]

Admittedly, the use of book figures will allow corporations some flexibility in determining their total tax base.

Nevertheless, that flexibility will be limited in the same manner that the corporation is limited in the preparation of its report to its own shareholders, creditors and Federal and State regulatory agencies with respect to its annual earnings and profits.

At the same time, the Alaska legislature could require the use of either book income or Federal taxable income, whichever is higher. In addition, the State could prescribe its own specific requirements for the determination of book figures.

Although we have recommended the use of book income as a means of determining the entire net income of petroleum companies for Alaska tax purposes, there are other approaches which are both feasible and reasonable. These other approaches would involve item by item adjustments, working either downward from book income or upward from Federal taxable income. Such adjustments themselves could take two forms. Alaska could choose simply to allow a specific tax incentive, regardless of whether the activities related to the incentive are conducted within or outside Alaska. On the other hand, Alaska could allow the tax incentive only if the incentive relates to Alaska activities. Precedents for the latter approach currently exist in a number of states which allow special deductions only for anti-pollution equipment used in the State, as well as the practice in New York of allowing double depreciation

deductions only with respect to property located in New York, and a Wisconsin law which requires tax savings from percentage depletion to be used only for prospecting in Wisconsin.

Another approach might be to limit each item by item adjustment for specific tax subsidies and incentives to an overall dollar amount. Precedent for this approach already exists in Alaska with respect to the investment tax credit which is limited to \$500,000.

If the legislature were to choose an item by item approach, we recommend that specific consideration be given to making adjustments which would include such items as the following:

1. The capitalization rather than the expensing of intangible drilling costs.
2. The elimination of accelerated depreciation including ADR. This could be done simply by limiting depreciation deductions to book depreciation.
3. The elimination of the distinction between capital gains and ordinary income (as now done by California and other states).

4. The capitalization rather than the expensing of such items as mine development costs, which are currently given preferred tax treatment under the Internal Revenue code.

5. The elimination of the deferral of tax on dividends from foreign subsidiaries (to be coordinated with combined report approach).

6. The disallowance of deductions for contributions to non-Alaskan charities.

7. The elimination of loss carryovers (as is currently done by California and a number of other states).

8. The disallowance of deductions for foreign expropriation losses.

5. Additional Consideration in Favor of Alaska's Departing from the Use of a Federally Defined Corporate Income Tax Base

During the recent presidential campaign, candidates from both of the major political parties expressed strong support for revisions of the present federal corporate income tax system which would integrate the corporate tax closely with the tax currently imposed on individuals. Under such an integrated system, individual shareholders rather than the corporation

itself, would tend to be taxable on corporate earnings.

Although it is, of course, impossible to predict what form, if any, federal legislation is likely to take with respect to the integration of corporate and individual income taxes, it is significant that the staff of the Joint Committee on Internal Revenue Taxation of the United States Congress is currently engaged in the development of Federal proposals. As a result, it is likely that Congress will soon legislate in this area. Under these circumstances, it also seems likely that in future years Federal definitions of taxable corporate income will become even more inadequate as a vehicle on which Alaska's corporate income tax can be "piggy-backed".

C. ANALYSIS OF ALASKA'S PRESENT ALLOCATION
AND APPORTIONMENT METHOD

Following is an analysis of Alaska's current method for determining the percentage of a corporate taxpayer's entire income that is attributed to the State for tax purposes. The data described and analyzed herein is based entirely on the actual tax returns and financial reports of actual corporations.

1. Present Law

Under the Uniform Division of Income for Tax Purposes

Act, which has been adopted by Alaska, the amount of a multi-jurisdictional corporation's entire taxable income that is currently attributed to Alaska is determined in the following way. The entire income is divided into two classes: "business" income and "non-business" income.^{7/} Non-business income (which is generally "passive income" received from investments) is ordinarily attributed to Alaska only if the corporation's "commercial domicile" (corporate headquarters) is located in Alaska. The corporation's "business" income is apportioned to Alaska on the basis of a three-factor formula comprised of the ratios of Alaska-to-total: Property, payroll and sales.^{8/}

For purposes of the formula, property included in the property factor is valued at its original cost. Wages are included in the numerator of the payroll factor if they are paid to employees who are covered by Alaska's unemployment insurance compensation laws. Sales are generally included in the numerator of the sales factor only to the extent that the products sold by the corporation are ultimately destined for consumption in Alaska. Special "throwback" provisions exist for assigning to Alaska sales made to the United States Government as well as sales made to customers in jurisdictions in which the corporation is not taxable.^{9/}

Like Oregon, California, Minnesota and a number of other states, Alaska currently requires affiliated corporations engaged in unitary businesses to file "combined reports".

Under the combined report approach, the entire income of the whole unitary corporate family from world-wide sources is combined and is then apportioned to Alaska on the basis of a combined apportionment formula. On a multi-corporate level, this method is thus the antithesis of so-called "separate accounting" or "direct accounting".^{10/}

[REDACTED] the application
[REDACTED] represent the extent
[REDACTED] the Alaska
[REDACTED] to be modified
[REDACTED] equitable
[REDACTED]
[REDACTED] taxpayer
[REDACTED] for the
[REDACTED] the
[REDACTED] administrators of most
[REDACTED] 12/
[REDACTED] to be
[REDACTED] engaged in non-
[REDACTED]

Finally, it is also significant to note that under Section 1 of the Uniform Act and Article IV of the Multistate Tax Compact, financial organizations and public utilities, including transportation companies, are expressly excluded from the application of the uniform apportionment rules.

2. Effect of Present Apportionment Method on Oil Companies

The following table (III) presents apportionment ratios for each of the thirteen largest petroleum companies doing business in Alaska. Two ratios are presented for the factors of each company. The ratios in the columns labeled "P.O." (Parent Only) generally reflect current practice, but exception as reported by the auditors are indicated. The ratios in the columns labeled "W.W." reflect current reporting practice in some cases, constructed ratios based upon the audits of actual tax reports in other cases, and constructed ratios based partially upon published data as well as data from tax reports or audits.

There are few new generalizations which can be drawn from this display of ratios and two generalizations sometimes made are at least partially refuted. For example, it is found that the property factor is not always the largest of the three factors such as cases H, I, J, M, and C demonstrate. The sales factor is not always the smallest, for example see cases H, J, L, A, C, D and F.

An additional observation is that the worldwide ratios for each company in the sample are quite generally smaller than the same ratio when it is calculated for a parent only or other less than world-wide combination. Possible exceptions are I, A and B, but in two of these cases, namely I and B, the compared ratios are for different years. The smaller ratios do not mean

that a smaller taxable income will be apportioned to Alaska because these ratios will usually be applied to a larger world-wide apportionable income. Table IV elaborates on this matter and compares apportioned income on a world-wide basis with apportioned income on less than world-wide basis.

TABLE III

APPORTIONMENT FACTORS FROM A SAMPLE OF TAX RETURNS
OF OIL COMPANIES OPERATING IN ALASKA IN RECENT YEARS
(Ratios are calculated from 1975 data except as noted)

Company	Property		Payroll		Sales	
	P.O.	W.W.	P.O.	W.W.	P.O.	W.W.
A	*.00539	.01117	.00275	.00222	.00483	.00451
B	.00457	.00916 ¹	.00300	.00340 ¹	.00223	.00080 ¹
C	.01758	.01214	.00240	.00167 (E)	.01272	.00001
D	.03672	.03462	.00065	.00030	.00925	.00808
E	*.06077	.05641	.03524	.02801	.01474	.01204
F	.06117	.04555	.04044	.03106	.04721	.02703
G	.01655 (E) .01479 ¹	.00888	.00392	.00188	.00070	.00035
H	.00293	.00177	.00069	.00034	.00359	.00135
I	*.01142 ¹	.02747	.03200 ¹	.03382	.00107 ¹	.00104
J	*.74726	.00336 ¹	.06058	.02537 ¹	.26374	.00023 ¹
K	N.A.	.03024 ¹	N.A.	.00664 ¹	N.A.	.00134 ¹
L	.08578 ¹ (incl. one sub.)	.02494 ¹ .02023	.02575 (incl. one sub.)	.01235 ¹ .01281	.05336 (incl. one sub.)	.00627 ¹ .00980
M	*.00684	.00189 ¹	.00533	.00214 ¹	.00058	.00018 ¹

FOOTNOTES:

E - Estimate based on tax reports and calculated by author.

P.O. - Parent corporation only except as noted.

W.W. - World-wide combined report.

N.A. - Not available.

¹ - Based on 1974 data.

* - United States Consolidated report.

In compiling the next table (IV), apportionment ratios have been applied to the apportionable income of each sample company. The ratios used to compile this table were the result of summing the property, payroll and sales ratios for each company and then dividing by three. This was done twice for each taxpayer i.e. once for the parent corporation and one or more of its subsidiaries which is the usual basis for filing the income tax report, and then again on a "world-wide" basis. The world-wide reports were constructed using tax reports and publicly recorded corporate financial data. Two companies in the sample did file their income tax reports on the world-wide basis in 1975 and these companies have been eliminated from the table.

A comparison of the results for the two basis for assigning taxable income to Alaska shows that the world-wide basis of reporting would assign the larger tax base to Alaska. In further comparison, the world-wide reporting basis produced positive estimates of taxable Alaska income for each sample corporation, but when the less than world-wide reports are examined, four companies in the sample reported negative taxable Alaska income totalling more than thirty-seven million dollars in 1975. It should be noticed that although this negative income assigned to the state from some companies does not currently offset the positive taxable income of other companies, under present arrangements the current year negative income can offset positive incomes in future years for those companies currently reporting the negative incomes.

In conclusion, the world-wide basis for reporting would have added an estimated six million dollars to the current year Alaskan tax base and if all current year negative incomes offset positive incomes, in future years, the world-wide basis for reporting income would result in an additional thirty-seven million dollar tax base increment for Alaska.

TABLE IV
COMPARISONS OF APPORTIONED INCOME FOR A SAMPLE OF OIL COMPANIES
OPERATING IN ALASKA IN RECENT YEARS
(Data for 1975 except as noted)

<u>COMPANY</u>	<u>APPORTIONED INCOME TO ALASKA (\$'s)</u>
A P.O.	266,553
Sub-1	(23,721,269)
Sum	(23,454,716)
W.W.	2,405,587
W.W.	11,740,204
B P.O.	943,209
W.W.	2,316,031
C P.O.	N.A.
W.W.	14,112,151
D P.O.	(375,032)
Sub-1	(13,525,636)
W.W.	155,153
E P.O.	N.A.
W.W.	2,419,211
F P.O.	16,742,538
Sub-1	(65,894)
Sub-2	45,069
Sum	16,721,713
W.W.	2,705,775

G	P.O.	4,584,363
	Sub-1	(209,073)
	Sum	4,374,385
	W.W.	13,694,535
H	*P.O.	3,027,848
	W.W.	5,760,441
I	P.O.	2,494,124
	Sub-1	(Negative)
	Sum	2,494,124
	W.W.	445,184
J	P.O.	2,870,420
	Sub	N.A.
	W.W.	2,872,837
K	P.O.	1,580,332
	W.W.	2,451,381
L	P.O.	11,661,485
	W.W.	15,861,009
M	P.O.	9,469,155
	W.W.	10,892,032

FOOTNOTES

P.O. - Parent corporation only except as noted.

W.W. - World-wide combined report.

N.A. - Not available.

1 - Based on 1974 data.

2 - This is an alternative estimate which probably incorporates a substantial redefinition of Alaska tax base. It is not used in the summary explanation of the tabulated information.

3. Effects of Alternate Methods

The next table (V) compares the results of using a two-factor formula (property and payroll), rather than the presently prescribed three-factor formula, to apportion income to Alaska for the purpose of taxing it. The two-factor formula assigned about 25 million dollars of additional taxable income to Alaska when it was applied to worldwide apportionable income. This incremental income was derived from twelve of the thirteen sample companies and the thirteenth company assigned slightly less income to Alaska by the two-factor formula than by the currently used three-factor formula. The origin-oriented two-factor formula will add slightly more than 25 million dollars to the State tax base.

TABLE V
APPORTIONMENT RATIOS BASED ON PROPERTY AND PAYROLL
AND THEIR EFFECTS ON INCOME APPORTIONED TO ALASKA
(Data for 1975 -- World-wide except as noted)

COMPANY	APPORTIONMENT RATIOS		APPORTIONED INCOME (\$'s)		ADDITIONAL APPORTIONED INCOME (\$'s) (2 F minus 3 F)
	2 Factor	3 Factor	2 Factor	3 Factor	
A	.031	.021	20,813,427	14,112,151	6,701,276
B	.002 ¹	.001 ¹	19,710,349	13,694,535	6,015,814
C	.005	.003	4,557,061	2,405,587	2,151,474
D	.018 ¹	.013 ¹	3,447,469	2,419,211	1,028,258
E	.017 ¹	.014 ¹	3,130,587	2,705,775	424,812
F	.001	.001	2,124,707	2,316,031	(191,324)
G	.014 ¹	.010 ¹	230,960	155,153	75,807

H	.007	.006	6,459,992	5,760,441	699,551
I	.006 ¹	.004 ¹	628,510	445,184	183,325
J	.007	.005	4,303,023	2,872,837	1,430,185
K	.017	.014	2,980,579	2,451,381	529,198
L	.042	.032	20,824,050	15,861,009	4,963,041
M	.038	.035	12,066,075	10,892,032	1,174,043
TOTAL					25,185,460

FOOTNOTE
1 - 1974 data

The following table (VI) indicates that the origin oriented extraction factor is appreciably larger than the sales destination factor which is currently used. Since the origin-oriented factor is only one of three factors in the apportionment formula, the effect of the factor is shown by table VII after it is combined with the property and payroll.

TABLE VI
SALES (DESTINATION) FACTOR COMPARED WITH
THE EXTRACTION (ORIGIN) FACTOR

<u>Company</u>	<u>Sales Factor</u>	<u>Extraction Factor*</u>
A	.000 (35)	.013
B	.001	.003
C	.001	.041
D	.000 (23)	.005
E	.001	.045
F	.006	.037
G	.000 (18)	.003

H	.027	.068
I	.012	.056
J	.008	.052
K	.000(01)	.018
L	.001	.014
M	.005	.017

* Extraction factor based on estimates of Crude Oil Extraction for the late 1970's and early 1980's.

As the next table (VII) indicates, three factor origin formula adds a total of more than 50 million dollars to the Alaska tax base -- an amount about equal to the total tax base of the sample companies for 1975.

TABLE VII
APPORTIONMENT RATIOS BASED ON THREE FACTOR FORMULAS
i.e. PROPERTY, PAYROLL AND SALES, AND
PROPERTY, PAYROLL AND EXTRACTION
(Worldwide Ratios for 1975)

Company	3 Factors Sales Destination	3 Factors Origin*	Tax Base Differences (Origin - Destination) \$'
A	.003	.008	4,370,713
B	.002	.002	1,711,849
C	.021	.034	8,979,919
D	.010	.011	21,705
E	.013	.027	2,628,601
F	.014	.025	2,031,795
G	.001	.002	5,869,087
H	.006	.010	3,888,539
I	.004	.009	455,348

J	.005	.011	3,982,088
K	.014	.030	2,669,889
L	.032	.056	11,769,255
M	.035	.048	4,229,968
TOTAL			52,608,956

* The origin factor is based on estimates of crude oil production for the late 1970's and early 1980's.

4. Effects of Separate Accounting

The next table (VIII) presents Alaska's recent experience with separate accounting as used by seven of the thirteen companies in the sample. In 1975 several of these companies began to apportion income to Alaska and in one instance, income assigned to Alaska was both apportioned, as well as assigned by the separate accounting method.

but
input
written
in 1975
2-1-80
Joh
16-2-80
19-2-80

[REDACTED] noticed
[REDACTED] any
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED] Apportioned income was not available for the
remaining case. Further generalization cannot be made except
to notice that [REDACTED]
[REDACTED] accounted for to Alaska
year, the [REDACTED]
[REDACTED]

The total of incomes definitely assigned to Alaska by separate accounting for 1973 was about negative 8.5 million dollars, for 1974 the sum so assigned was over negative 35 million dollars and for 1975 the incomes assigned to Alaska by separate accounting added to over negative 36 million dollars. The 1975 amount is probably smaller than would have been the case had all of the 1975 apportioning taxpayers or the auditors made a determination of the Alaska taxable income by the separate accounting methods used in prior years.

The negative incomes assigned to Alaska in 1975 by the apportionment method were almost 14 million dollars and the positive incomes so assigned for 1975 amounted to more than 8 million dollars. The negative incomes cannot reduce the positive incomes of other current year taxpayers. Thus, there was an appreciable increase in Alaska taxable income for 1975 as these taxpayers were shifting to the apportionment method for reporting Alaska taxable income. The 1975 negative incomes would as usual be available to reduce Alaska taxable incomes in future years for the companies reporting those negative incomes in 1975.

See table on following page.

TABLE VIII

COMPANIES WHICH USED SEPARATE ACCOUNTING IN 1973, 1974, AND 1975,
 THE TAXABLE INCOME ASSIGNED TO ALASKA BY THAT METHOD AND
 ALTERNATIVE METHODS WHENEVER POSSIBLE

		1973 TXBL. INC.	1974 TXBL. INC.		1975 TXBL. INC.	
		Sep. Acctg.	Sep. Acctg.	Apport.	Sep. Acctg.	Apport.
A	P.O.	(4,688,123)	(15,997,275)		N.A.	2,870,420
	Sub ₁	0	0		N.A.	N.A.
D	Sub ₁	N.A.	N.A.		N.A.	N.A.
E	Sub ₁	N.A.	(2,294,094)	(6,060,885)	(23,721,209)	N.A.
H	P.O.	0 ¹	0 ¹		N.A.	(375,032)
	Sub ₁	0 ¹	0 ¹		N.A.	(13,525,636)
I	P.O.	0 ²	0 ²		0 ²	N.A.
J	P.O.	(1,829,201)	(2,784,713)		N.A.	3,027,848
K	P.O.	(1,979,609)	(16,248,961)		(12,748,645)	2,494,124
	Sub ₁	(165)	(165)		(170)	N.A.

FOOTNOTES

P.O. - Parent corporation only.

1 - Not greater than zero for these cases.

2 - Known to be a negative amount.

D. REVENUE EFFECTS OF PROPOSED LEGISLATION

Four steps have been taken to estimate the revenue impact of our recommended revisions of the Alaska corporate income tax.

The first step in the analysis considered the revenue effects of shifting from a less than world-wide basis for identifying total apportionable income to the world-wide basis for identifying total apportionable income. Table IV presented this data and concluded that Alaska would realize a six million increase in its tax base for 1975 or an estimated increase in revenue of \$564,000. This estimate does not in any way recognize that the taxable income as apportioned to Alaska on a less than world-wide basis assigns negative income of \$37,000,000 to Alaska which could in part or in its totality offset future years' taxable income. If this occurred, a future revenue loss of about 3.5 million dollars could occur. It is our understanding that the Department of Revenue is already moving toward the world-wide basis for apportioning income which will not only increase current year taxable income but it will substantially reduce the threat which any current year negative incomes pose to revenues in future years.

The second stage of the analysis focuses on several alternative ways of assigning world-wide income to Alaska. As previously noted in Table VIII, in recent years separate accounting has never assigned positive taxable income to Alaska. The negative incomes so assigned could as usual reduce future taxable income. Disregarding

these carryover possibilities, the separate accounting methods for this sub-set of the sample shows a loss of revenue for 1975 of \$799,000 when compared with the apportionment methods which were alternatively applied.

Two origin-oriented formulas were used to estimate the revenue effects of such formulas. One formula is a reduced version of the present formula, that is, a two-factor formula combining property and payroll. This formula, when applied to 1975 world-wide income, produces a tax base which is 25 million dollars larger than the tax base assigned by the present destination oriented formula. The increment in revenue would be \$2,350,000. The second origin-oriented formula is a three-factor formula which combines property, payroll and the extraction factor defined earlier in this report. This factor was estimated for the early production period of the Prudhoe Bay fields. When the three factor apportionment formula containing this third origin-oriented factor is applied to 1975 world-wide income, an additional 53 million dollars of tax base is assigned to Alaska, yielding an estimated \$4,944,866 corporate income tax revenue. It should be noticed that if the extraction factor based only on Cook Inlet crude production would assign a smaller tax base to Alaska to the extent of 7.5 million dollars, it would have led to a revenue loss of \$705,000. The production prospects for the next decade or two makes this historical hypothetical calculation interesting by way of the contrast it emphasizes.

At this point, it is worthwhile to note that on the basis of

a sampling of smaller companies operating in other industries that the presently used sales factor was about the equal of the property factor -- thus [REDACTED] have experienced

[REDACTED] differential effect of [REDACTED] with the large multi-

Thirdly, the total apportionable income, though conveniently keyed to the Federal tax returns, need not be defined as Federal taxable income. The equally available alternative which is not diminished by "Federal tax expenditures" is the [REDACTED] estimates are made of the differences between a book income base and a federal taxable income base. On a nationwide level, these differences amount to two to three billion dollars annually for the companies in the Alaska sample. Alaska's share of this nation-wide amount would have increased Alaska's tax base by about 57 million dollars and its corporate income tax revenue by \$5,375,000.

Finally, it must be noticed that for the fairly near future the apportionment factor based on property will increase due to the rapid increase of property in Alaska and the large amount already under construction but not yet incorporated into the apportionment ratios. This property would increase the numerators and the denominators of the apportionment ratios by the same absolute amounts but the increase in the numerators would outweigh the influence of changes in the denominators. By 1978 about 8.5 billion dollars worth

of property now under construction will be added to the present Alaska property. Making a very conservative estimate of the revenue impact of this change in the property factors for the several large companies, Alaska will still realize a substantial increase in revenue. The Alyeska Pipeline properties have been included in this estimating process. Applying the new property ratios to 1975 income would have increased the State tax base by at least 70 million dollars for an additional \$6,500,000 of tax revenue.

The payroll factor in the apportionment formula could be expected to change in future years. The change, however, would be modest as compared with the property factor. Furthermore, the changes in payroll which occur for the entire State would involve construction activity more than active petroleum production. For example, contract construction employment increased three to four times for the 1973 to 1975 period; that is from 8,000 to 28,000 employees. During the same period, employment in extractive activities went from 2,000 to 4,000 employees, while manufacturing employment was very steady. Interpreting this data from the Bureau of Labor statistics, it is concluded that the decline in employment in construction is going to be relatively large and that the decline in employment by the oil industry will be of little or no consequence for the assignment of taxable income to Alaska.

~~the revenue impact of suggested changes in the~~
corporate income tax, ~~the revenue impact of suggested changes in the~~
~~the revenue impact of suggested changes in the~~

[REDACTED] income, (2) by /

[REDACTED] formula

[REDACTED] and,

[REDACTED] into /

[REDACTED] The revenue impact of these changes are based on 1975 incomes. The growth of corporate income which would normally occur would, of course, increase the revenue productivity of the corporate income tax. The changes in the tax would apply to any increments in tax base as they develop and would have the same effect on the Alaska tax base and revenue as already set forth.

E. SOME ADMINISTRATIVE CONSIDERATIONS
IN FAVOR OF THE PROPOSED LEGISLATION

In formulating our recommendations, we gave careful consideration to the enforcement aspects of Alaska's income tax. We recognize that the State is rapidly developing advanced techniques for the administration of its tax programs. In this regard, it is important also to recognize that [REDACTED] insurmountable

[REDACTED] assigned to cope /

[REDACTED] characterize /

[REDACTED] some of which

[REDACTED] as great as /

[REDACTED]

One of the significant ways in which the State is currently developing its enforcement capacity vis-a-vis multi-national corporations is through its participation in the joint audit programs of the Multistate Tax Commission. As a result, we have been concerned with the formulation of a proposal which would allow Alaska to continue to participate in that program.

To ascertain the extent to which our recommendations can be implemented without disrupting Alaska's working relationship with the Multistate Tax Commission, we have interviewed the Commission's Executive Director and members of its staff. Based on these interviews, we have concluded that the Commission's audit staff can easily adapt its joint audits to accomodate the extraction factor of the apportionment formula that we are recommending. At the same time, we have been assured by the Commission's audit staff that the use of "book income" would make such audits easier to conduct than under the present tax laws. As a result, we feel confident that our proposals would increase, rather than decrease, the benefit that Alaska is able to receive from its participation in the Multistate Tax Commission.

F. COMPARISON OF PROPOSED LEGISLATION WITH
PROPOSALS FOR A "NET PROCEEDS" TAX
BASED ON SEPARATE ACCOUNTING

In formulating our recommendations, we have also considered the arguments previously advanced to the Legislature in support

of various forms of "net proceeds" taxes based on separate accounting.^{13/} However, since the net proceeds tax involves new concepts which have neither been developed by the Federal Government or by other states (with the possible exception of some features of the Nevada tax), no data based on real experiences with real tax returns is available to assess the true economic impact of the net proceeds tax. Both because of the lack of such economic data, and because of administrative difficulties with similar separate accounting methods, with which we have had experience, we recommend against the adoption of a net proceeds tax.

1. Administrative Difficulties with Separate Accounting

The use of separate accounting is based on the assumption that, although the total income of a corporation may be derived from interstate transactions and from many sources in many states, it is possible to isolate hypothetically those portions of the multi-jurisdictional business which are within a single state. The corporation's activities within the taxing state are regarded as though they were carried on by a separate and distinct in-state entity. Income is recomputed for this hypothetical entity without reference to the capital, receipts or operating expenses of the remainder of the corporation.

The use of separate accounting is widely resisted by State Tax Administrators in the case of unitary businesses. As we

have indicated above, its use has also been rejected by the United States Supreme Court.^{14/} Likewise, separate accounting was prohibited under the recommendations unanimously adopted by the Judiciary Committee of the United States House of Representatives, following the comprehensive investigation of State tax systems which were conducted from 1961 through 1966.^{15/} Nevertheless separate accounting is often advanced by multinational corporations as their ideal method for determining income attributable to the taxing State.

The reasons for the rejection of separate accounting by progressive State Tax Administrators becomes apparent from a consideration of some of the administrative and theoretical problems presented by this method.

In case of a multi-national petroleum company, only some of whose affiliates operate in Alaska, the use of separate accounting requires not only that hypothetical prices be established for goods or services between affiliates, but also requires an item-by-item analysis of all inter-affiliate loans, credit arrangements, dividend arrangements, partnership agreements, joint ventures, profit sharing arrangements, etc. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

Under the circumstances, it is not surprising that a large lobby group of multi-national corporations known as COST (Committee on State Taxation) has been formed to press both the United State Congress and State Legislatures for legislation permitting them to use separate accounting techniques for State tax purposes. It is also noteworthy that COST is comprised of ninety-two of the one-hundred largest corporations in the United States and is both an advocate of separate accounting forms of taxation as well as an opponent of the joint audit program of the Multistate Tax Commission.^{16/}

The use by large, vertically-integrated petroleum companies of separate accounting techniques for tax avoidance purposes in Alaska was demonstrated above by Table VIII. In general, this table shows that during 1973, 1974 and 1975, when seven of the largest oil companies operating in Alaska used separate accounting to determine their Alaska taxable income, in no case was any income assigned to Alaska. Instead, each separate accounting was asserted (by the taxpayer) to have demonstrated that the Alaskan operations were being conducted at a loss.

Although on the surface, the separate accounting techniques called for under the net proceeds tax proposals may appear to be more simple than the use of separate accounting in the present income tax, in reality the problems created

under the net proceeds tax would be even more complicated, and tax avoidance possibilities even greater than under the present income tax.

Under the net proceeds tax proposals not only is the multi-national corporation able to set up its separate accounts for its Alaska operations and its operations in other states, it is also permitted to make its own separate determinations regarding the degrees of profitability of its oil-producing operations as distinct from its oil transportation and refining and marketing operations as well as from all of its other income producing activities. At the same time, after isolating the oil extracting operations for tax purposes, it is able to arrange its own internal finances in such a way as to use costs and expenses relating to its oil-extracting operations on the outer continental shelf off the coast of Alaska to offset and reduce its tax liability for on-shore drillings.

[REDACTED] accounting features of [REDACTED]
[REDACTED]
[REDACTED] the [REDACTED]
[REDACTED] [REDACTED]
[REDACTED] separate ac- [REDACTED]
[REDACTED]
[REDACTED] production in Alaska [REDACTED]
[REDACTED] on-shore oil opera- [REDACTED]
[REDACTED] in this regard it is [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

In comparing the net proceeds tax with the present income tax, proponents of the net proceeds tax tend to argue that by giving the Department of Revenue the statutory authority to determine oil prices for the purposes of the tax, the disadvantages of separate accounting can easily be obviated. However, this argument ignores the realities of even the most conventional modern tax avoidance techniques in everyday use. These techniques may be illustrated by the following example.

Affiliate A, which is taxable in Alaska, engages in a complex variety of transactions with affiliated support companies. The support companies are not taxable in Alaska and charge large service or sales prices which increase the cost of expenses of A. Such support companies perform engineering and geological studies, sell drilling equipment and supplies, transport such equipment and supplies to the Alaska site, etc. While maintaining a high total income of the combined group, the oil production net proceeds of A is kept low by assigning to A a disproportionate amount of deductions.

In such a case, proponents of separate accounting point out that the Department of Revenue would have the legal authority to recompute all of the transactions among all of the parties and their affiliates. However, for the Department of Revenue to do so would involve an extraordinarily

[REDACTED] of each
[REDACTED] would be simi-
[REDACTED] and as an extra-
[REDACTED] Section 482
[REDACTED]

On a Federal level, under Section 482, the Secretary of the Treasury has long had the power to re-allocate income and deductions among affiliated companies when "necessary in order to prevent evasion of taxes or clearly to reflect the income of any of such organizations." However, the difficulties of administering Section 482 has been found so great as to limit severely the usefulness of this power, even as an extraordinary remedy on a Federal level.^{17/} Under the circumstances, since the problems posed by separate accounting on a State level are even more complex than on a Federal level,

[REDACTED] simply are
[REDACTED] to rely
[REDACTED] an-
[REDACTED]

This is not only true with states such as Alaska, which has a comparatively small audit staff, but is also true with respect to such states as California, which has the largest and most experienced audit staff in the United States.

2. Inequities Created by Attempts to Provide for Credits
Between the Current Income Tax and the Proposed Taxes
on Net Proceeds

The difficulties in this area emanate from the fact that the income tax currently in effect in Alaska like the income taxes of all other states, is both apportioned and includes income from all sources and from all types of activities. Thus it includes income from refining, transportation and marketing of oil and petroleum products, as well as income from other activities. In contrast, the proposed net proceeds tax would apply only to the net proceeds from the extraction of petroleum.

Recognizing that if the net proceeds tax is imposed as a separate and distinct tax, oil producing corporations will be subject to double taxation, the proponents of the net proceeds tax generally suggest that the tax be imposed in lieu of the income tax or that one of the two taxes be creditable against the other. However, a careful analysis of such credit arrangements suggests the impossibility of relating the two taxes to each other in a way that will not create significant inequities, especially for local Alaska companies that are unaffiliated with multi-national enterprises.

On the one hand, if the net proceeds tax is imposed "in lieu" of the corporate net income tax, then a petroleum

producing conglomerate would be allowed to earn "tax free" income from a wide variety of business activities other than the extraction of petroleum. For example, a multi-national oil-producing corporation could operate a hotel in Alaska and escape income taxation entirely with respect to its earnings from the hotel operations.

If the net proceeds tax is allowed as a credit against the corporate net income tax, then a large petroleum corporation with a large oil production would be able to use the net proceeds tax as a "shelter" to escape tax on Alaska activities that are not directly related to the extraction of petroleum. For example, the large petroleum corporation could purchase an Alaskan fishing enterprise and use the credit from the net proceeds tax to decrease its liability for the income tax imposed on the combined income from both petroleum production and fishing operations.

If, on the other hand, the income tax is allowed as a credit against the net proceeds tax, a multi-national corporation operating a fishing business or a construction company either in Alaska or outside of Alaska would be able to reduce its liability under the net proceeds tax to the extent that it is able to derive income from fishing or construction either inside or outside of Alaska.

As each of these examples illustrates, the effect of efforts to provide for inter-related credits between the two types of taxes would be to give unfair tax advantages to large conglomerate types of operations that would not be available to smaller corporations that are neither members of affiliated groups nor engaged in a variety of income producing activities.

G. FURTHER RECOMMENDATIONS

1. On-shore Economic Impact of Outer-Continental Shelf Operations

In conducting our analysis of the present system of corporate income taxation in Alaska, we became aware of the inter-relationships between the on-shore activities of petroleum companies and activities of some of the same companies with respect to the outer continental shelf. In view of the fact that the outer continental shelf activities have a profound economic impact on the State and obviously creates substantial need for governmental services provided by the State, it would seem reasonable for the State to structure its taxes in such a way as to relate the tax burdens of companies that operate on the outer continental shelf to the benefit which those companies derive from services provided on-shore by the State of Alaska.

[REDACTED] economic impact of the outer
[REDACTED] the state, we recommend
[REDACTED] and the extraction factor in
[REDACTED] formula be defined to reflect
[REDACTED] on the outer continental
[REDACTED] serviced from on-shore facilities

Such an apportionment device would be similar to the "throw-back" principle already embodied in the present sales factor of the Uniform Division of Income for Tax Purposes Act. Under the Uniform Act, sales of goods shipped into states and foreign countries in which the corporation is not taxable are "thrown back" to the state in which the goods originate. Similarly, property and extraction activities not located in any state in which the corporation is taxable, ought appropriately to be assigned to the Alaska numerator if the property and extraction activity are serviced from on-shore bases of operation in Alaska.

We recognize that the case law may be somewhat unsettled concerning the power of the states to take the on-shore economic impact of outer continental shelf activities into account in the apportionment of State taxes measured by net income. Since we have not conducted a detailed analysis of the case law and have not made any revenue estimates of the outer continental shelf activities, our recommendations concerning the on-shore impact of outer continental shelf activity are still tentative.

2. Alaska's Participation in Multistate Tax Commission

Under AS 43.19.030 provision is made for oversight by appropriate committees of the manner in which the Multistate Tax Commission is functioning with respect to Alaska's tax program. It should be noted that to date these committees have not been constituted.

As indicated above, during the course of our investigation we have conferred with the Executive Director and Audit Staff of the Multistate Tax Commission. Because of the Commission Staff's involvement with the audit of large vertically-integrated corporations on a nationwide and worldwide basis, the staff has been able to provide us with invaluable information, as well as a number of helpful suggestions. In our judgements, substantial benefits can be derived by Alaska from continued participation in the Multistate Tax Compact.

3. Applicability of Proposed Legislation to Production and Transportation of Gas

Although our study has been limited to the income taxation of oil companies, [REDACTED] our

[REDACTED] As a result, a draft bill that we have prepared covers the taxation of income from both oil and gas.

4. Gross-Valued Severance Taxes

It is important to note that the preceeding analysis has been devoted exclusively to a consideration of "net" types of taxes which are measured by profitability and, therefore, provide for substantial deductions from the taxpayer's gross earnings. Under the decisions of the United States Supreme Court,^{18/} such "net" types of taxes are generally required to be imposed in some manner that reasonable apportions the total tax base among each of the States in which the interstate corporation is engaged in interstate commerce.

In contrast, the United States Supreme Court has not required severance types of taxes measured by the "gross" value of resources extracted to be determined in a manner that apportions the tax base among any of the states to which the extracted resources are eventually transported or sold.^{19/}

Although we have made no specific recommendations with respect to the form or rates of any severance taxes which are, or might be, imposed by Alaska, [REDACTED]

[REDACTED]
[REDACTED] also
[REDACTED]

Background of Authors

Mr. Zeifman is currently an Associate Professor of Law at Santa Clara University School of Law, Santa Clara, California. He formerly served as General Counsel to the Committee on the Judiciary of the U. S. House of Representatives, as well as Chief Counsel to the Special Subcommittee on State Taxation of Interstate Commerce. He has also served as Chief Counsel to the Subcommittee on Anti-Trust and the Subcommittee on the Outer Continental Shelf.

Mr. Ainsworth is a Professor of Economics and is Chairperson of the Department of Economics at Allegheny College, Meadville, Pennsylvania. He was formerly an Economist on the staff of the Special Subcommittee on State Taxation of Interstate Commerce. He has also served as a consultant in the revisions of the tax systems of New York City, the State of Connecticut and the District of Columbia.

Both of the authors confine their non-teaching professional activities to government service.

Footnotes

- 1/ AS 43.20.021
- 2/ AS 43.19.01
- 3/ See, Report of the Special Subcommittee on State Taxation of Interstate Commerce of the Committee on the judiciary of the U.S. House of Representatives (Hereinafter referred to as the Willis Subcommittee Report), H. Rpt. 1480 (1964), Vol. Vol. 1, p. 143.
- 4/ Colonial Pipelines vs. Triagle, 95 S. Ct. 1538 (1975)
- 5/ Similar tests were recommended by the House Judiciary Committee in the "Willis Bill" and the "Rodino Bill," both of which were approved by the U.S. House of Representatives.
- 6/ Budget Options for Fiscal Year 1977, as Required Annually by P.L. 93-3-344, Congressional Budget Office, March 15, 1976.
- 7/ See Willis Subcommittee Report, Vol. 1, pp. 276-278.
- 8/ AS 43.19.010, Article IV 4 to IV 8
- 9/ AS re.19.010, Article IV 9 to IV 17
- 10/ Ibid.
- 11/ AS 43.20.031
- 12/ See Willis Subcommittee Report, Vol. 1, p. 167
- 13/ See Walgreen Co. vs. Commissioner of Taxation, 258 Minn. 522, 104 N.W. 2d 714 (1960), appeal dismissed 365 U.S. 767, 81 S. Ct. 912 (1961); Butler Bros. vs. McColgan, 315 U.S. 501, 62 S. Ct. 701.
- 14/ We have assumed that a "net" proceeds tax would be measured by some concept of profitability and would therefore provide for significant amounts of deductions.
- 15/ See note 13.
- 16/ See Willis Subcommittee Report, Vol. 4.
- 17/ See Willis Subcommittee Report, Vol. 1, p. 165; and H. Rept. 1447, 87 Cong., 2d sess, p. 28 (1962)
- 18/ See Northwestern States Portland Cement Co. vs. State of Minnesota, 358 U.S. 450, 79 S. Ct. 357 (1959). See also, Willis Subcommittee Report, Vol. 3, pp. 1037-1039.

- 19/ See Hope Natural Gas Co. vs. Hall 274 U.S. 284 (1927);
Oliver Iron Mining Co. vs. Lord, 262 U.S. 172, (1923);
Heisler vs. Thomas Colliery Co., 260 U.S. 245 (1922);
American Mfg. Co. vs. St. Louis 250 U.S. 459 (1919). See
also, Willis Subcommittee Report, Vol. 3, p. 1041, 1042.

PRESENTATION OF TABLES

- * To avoid the identification of individual companies the letter designation used in any particular table do not necessarily correspond with the letter designations used in any other tables.

Alaska's Oil and Gas Tax Structure:

A Study with
Recommendations
for Improvement

February 1977

Prepared by
State of Alaska
Department of Revenue

STATE OF ALASKA

DEPARTMENT OF REVENUE

OFFICE OF THE COMMISSIONER

JAY S. HAMMOND, GOVERNOR

POUCH 5 - JUNEAU 99811

February 11, 1977

The Honorable Jay S. Hammond
Governor, State of Alaska
Juneau, Alaska 99801

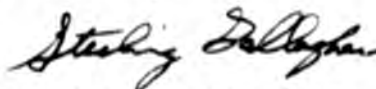
Dear Governor Hammond:

I am pleased to transmit to you for your consideration the Department of Revenue's Study of Alaska's Oil and Gas Tax Structure with recommendations for improvement.

During the last several months the Department has examined each of the State's major oil and gas taxes for potential deficiencies as well as examining the State's future revenue needs. As a result of this comprehensive review, I am recommending several changes in the State's tax system. These recommended changes apply to each of the State's major oil and gas taxes: production tax, property tax, reserves tax and corporate income tax.

I plan on holding hearings in both Anchorage and Juneau to receive public comment on the recommendations contained in the study. After public comments, I will make specific proposals for legislative consideration.

Sincerely,



Sterling Gallagher
Commissioner

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FOREWORD

During the 1976 Session of the Ninth Alaska State Legislature, several proposals were made to provide for new and, in some cases, unprecedented taxes on the petroleum industry as it operates in the State of Alaska. Before making any recommendations for change the Department of Revenue recognized the need to gather additional data to evaluate properly the impact of existing or new tax structures. Therefore a study was proposed by the Department to make this analysis and give informed recommendations.

In addition, pursuant to CS SCR 101, the Alaska State Legislature resolved that the Legislative Council was to cooperate with the Governor in undertaking a comprehensive and definitive study of Alaska's present oil and gas leasing and taxation policies, with recommendations to be made regarding those policies for the future.

Accordingly, during the past several months the Department of Revenue, in cooperation with the Legislative Council's Interim Committee on Oil and Gas Leasing and Taxation Policy, undertook a study of the State's taxing policy as it relates to the oil and gas industry.

The Department of Revenue and the Legislative Council

jointly retained three consultants to study the State's corporate income tax. On January 9, 1977, Jerome M. Zeifman and Kenneth G. Ainsworth submitted a report to the Alaska State Legislature and the Department of Revenue entitled "The Taxation of the Petroleum Industry Under Alaska's Corporate Income Tax."

In approaching the study the Department saw the need to resolve several questions to evaluate any recommendations for change. Generally these questions were:

1. What are the revenue needs of the State over the short and long term?
2. Are there gaps or loopholes in the present tax structure?
3. Is the tax structure able to respond to new and different types of oil and gas development in the state and off its shores?
4. Are the tax revenues subject to domination by outside forces such as industry pricing and federal decision making?

The overall objective of the study was to suggest a stable tax system sufficient to meet the State's revenue

needs and respond to changes in economic conditions, federal policies and industry operations. It is believed by the Department of Revenue that it is necessary to examine the State's entire oil and gas tax structure. A look at only one tax or one part of the structure in isolation provides an inadequate picture.

In Chapter I the study begins with a description of the nature of oil and gas operations in Alaska and their geography.

No recommendations or changes in the tax structure should be made without a thorough understanding of how the existing system works. Accordingly, the history and the present workings of each oil and gas related tax are explored in Chapter II.

In addition any recommendation on appropriate tax policy must have as its primary emphasis the revenue needs of the state in the near and long term future. On this subject the study presents in Chapter III a review of the expenditure and revenue patterns from 1969 to the present, with some observations concerning earlier expectations of government leaders regarding future revenues from oil and gas. From the pattern of expenditures to date, the report in Chapter IV projects budget expenditures and revenues of the State

through 1985 and beyond. On the expenditure side, the report notes certain items which are at this time still unknown and which could have significant impact on general State expenditures and revenues. These items include capital move costs, potential haul road costs, and alternative gas line routes. In addition federal pricing decisions or corporate decisions regarding North Slope oil could drastically alter projected petroleum revenues. Therefore the report includes both market-value as well as administered-price cases on petroleum revenue forecasts.

The report, after analyzing the present structure and the revenue and expenditure picture, then discusses deficiencies in several areas of the tax structure (Chapter V). The Department sees some deficiencies in each of the State's major taxes, including the corporate income tax, production tax, property tax and reserves tax.

In Chapter VI the report analyzes alternative solutions and makes specific recommendations based on the State's revenue needs and curing present deficiencies. Recommendations are made with regard to each of the State's major oil and gas taxes.

The final portion of the report contained in Chapter VII discusses the potential effects on the oil and gas industry, as well as the economy in general, with the adoption of the Department's recommendations.

CHAPTER I. OVERVIEW OF OIL AND GAS
OPERATIONS IN ALASKA

A. GENERAL

All four general phases of the oil business (production, transportation, refining and marketing) are carried on in Alaska. Compared to production and transportation (pipelines), however, refining and marketing are relatively minor activities.

At present the area in and around upper Cook Inlet is the only part of the state that is producing significant quantities of oil and gas, although some gas is being produced from a field near Barrow and limited quantities of oil and gas are produced from the Prudhoe Bay field to fuel field development activity there. The great majority of the present production of the Cook Inlet area comes from eight fields, in which a total of eleven major oil companies own interests. These companies are Atlantic Richfield, Marathon, Union, Mobil, Standard Oil of California, Texaco, Superior, Shell, Skelly, Phillips and Amoco (Standard Oil of Indiana).

Very soon the center of Alaskan crude oil and natural gas production will shift from Cook Inlet to Prudhoe Bay. Standard Oil of Ohio (affiliated with British Petroleum), Atlantic Richfield and Exxon are the major interest owners at Prudhoe Bay. A number of other companies have combined interests of five or six percent in the field. The oil from this huge field will be transported through the Trans Alaska Pipeline System (TAPS) to Valdez. Eight companies own TAPS,

six of which are pipeline subsidiaries of large oil companies. The other two are large oil companies themselves.

As with current crude oil production, the present center of Alaskan refining activity is in the Cook Inlet area near Kenai. Two rather small refineries are there, the larger being owned by Tesoro-Alaskan, the purchaser of the State's royalty oil from the offshore oil fields in the Inlet. Standard Oil of California owns the other. A third, smaller refinery is being built at North Pole. A small, simple refinery (topping plant) is operated by Arco at Prudhoe Bay to provide diesel fuel for the operations there. Additional topping plants will provide fuel for certain pump stations along TAPS.

Refined products are distributed in Alaska by four major oil companies and one independent. Standard Oil of California dominates the Arctic and Western Alaska markets and is a major force in the Interior, Southcentral and Southeastern markets. Shell markets jet fuel in Anchorage, while Texaco and Union market motor gasoline and fuel oils. The most recent entrant into the Alaskan market is Tesoro-Alaskan, which aggressively markets motor gasoline and fuel oils in areas accessible by road.

B. COOK INLET AREA

1. Oil fields in the Cook Inlet area. To understand the oil and gas industry in Alaska, it is helpful to review the economic geography of the five important oil fields in the Cook Inlet area. These are the Swanson River, Middle Ground Shoal, Granite Point, Trading Bay and McArthur River fields.

Swanson River. This field, comprised of the Swanson River and Soldotna Creek Units, is located east of the Inlet in the Kenai National Moose Range (see Figure I-1). The field is operated by Standard Oil of California (Socal), which owns about 49 percent of the production. Atlantic Richfield (Arco) owns an equal interest, with the remainder equally divided between Union and Marathon. The leases in the field are all federal leases.

All production from this field is transported from Swanson River via the Kenai Pipe Line Company's pipeline to one or the other of the two refineries at Nikiski or to the Nikiski marine terminal for tanker shipment out of Alaska.

Middle Ground Shoal. Middle Ground Shoal is a long narrow field in Cook Inlet, which underlies portions of five oil and gas leases issued by the State. Three of these leases are owned by the so-called Chakachatna group, which

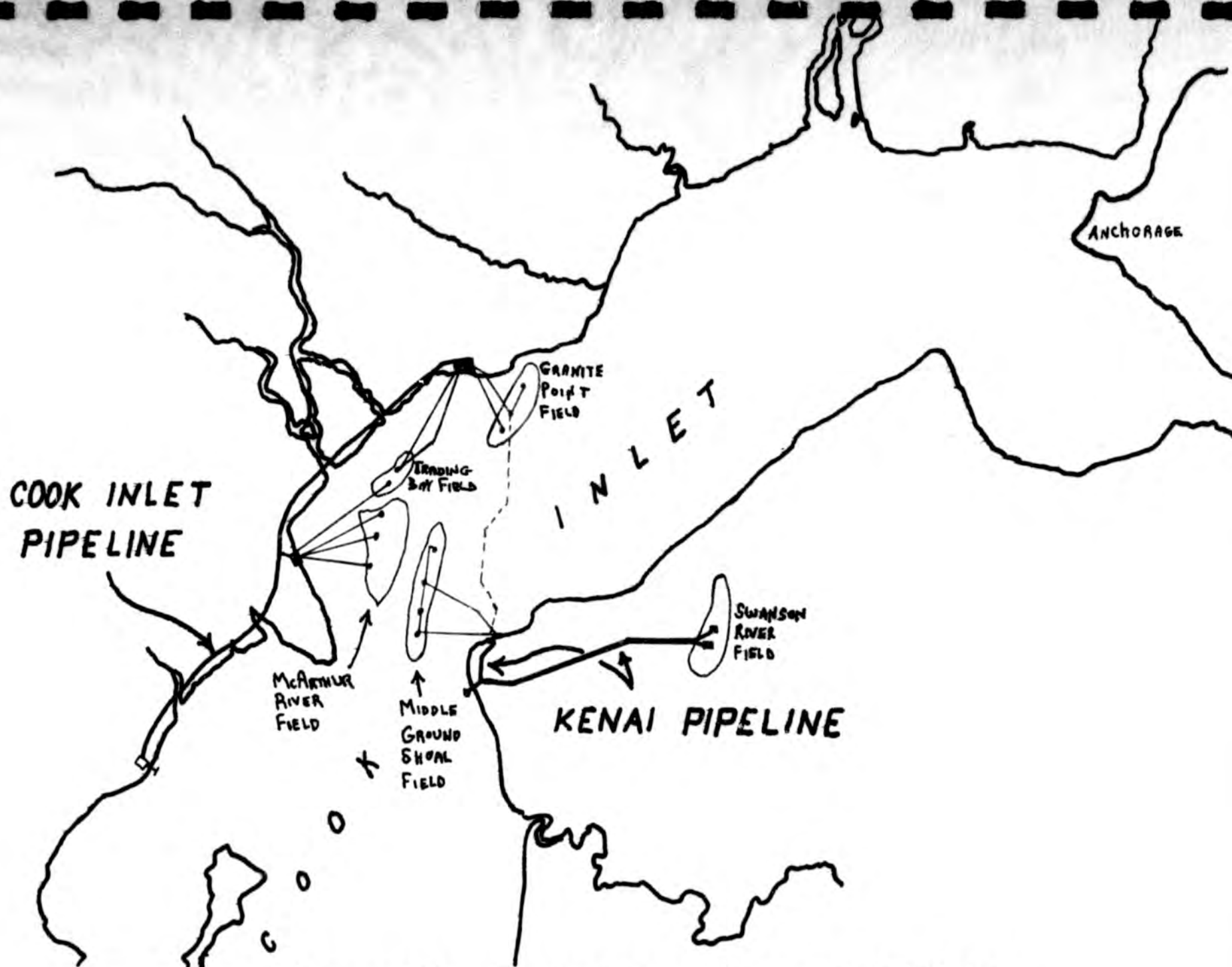


Figure I-1 Cook Inlet Area Oil Fields and Oil Pipelines

today consists of Amoco (25%), Phillips (25%), Skelly (25%), Arco (12.5%) and Socal (12.5%).

Between the Chakachatna leases are two leases owned by the SAS (Shell-Arco-Socal) group. Each company owns a one-third interest in each of the leases.

Four platforms have been used to develop Middle Ground Shoal field. The platforms at the north and south ends are called Baker and Dillon and are operated by Amoco. The two middle platforms, operated by Shell, are simply known as "A" and "C" (Figure I-2 shows the locations of these four platforms and their related pipeline connections).

Granite Point. This field in Cook Inlet has been developed from three offshore platforms. Two of these - Anna and Bruce - are operated by Amoco for the Chakachatna group's three State-issued leases. Platform "C" is operated by Mobil for a State lease issued to Mobil (75%) and Union (25%). Oil from all three platforms now moves to the Mobil-operated onshore production facility near Granite Point (see Figure I-2). Formerly, however, the oil from the Chakachatna leases was piped all the way across the Inlet to the onshore production facility operated by Amoco at East Foreland. These long lines proved difficult and very expensive to maintain and operate because of the rough bottom of the Inlet and the strong tides. After repeated breaks, the

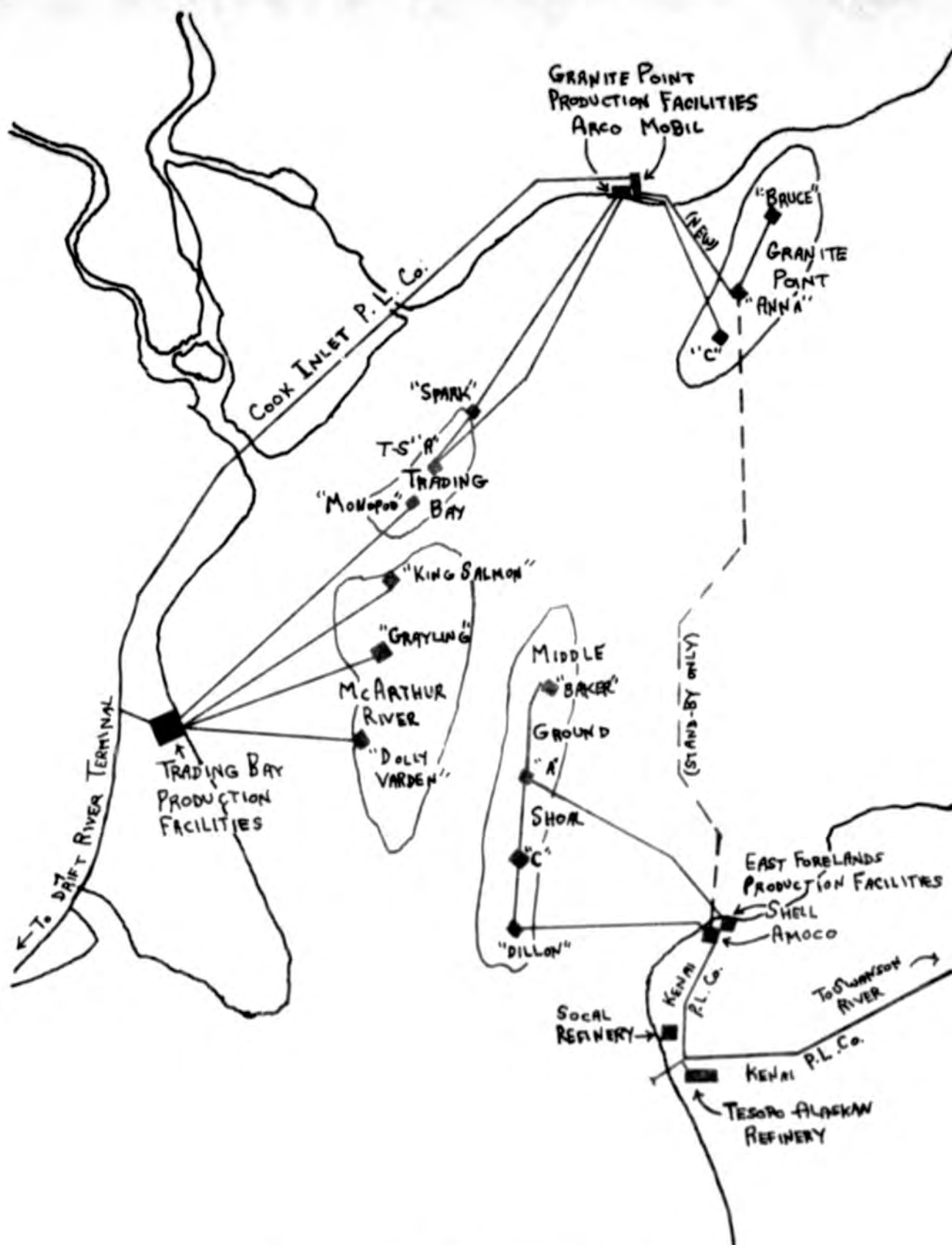


Figure I-2 Cook Inlet Offshore Oil Operations

present lines to the west shore of the Inlet were laid, and the old lines are now unused (see Figure I-2).

Trading Bay. Four State leases comprise the Trading Bay field. One, leased by Union and Marathon (50% each), is operated by Union. Two are entirely Arco's, and the other is leased by Texaco and Superior (50% each).

Trading Bay field has three platforms. The Monopod has been used to develop the Union-Marathon lease. Platform "A", located on the Texaco-Superior lease has wells bottomed in some pools that are also developed from the Monopod, and has other wells bottomed in another pool which underlies portions of the Texaco-Superior lease and the two Arco leases. This latter pool has been unitized, and Arco operates the unit wells. Under a separate service contract, Arco also operates the non-unit wells drilled from Texaco-Superior platform "A". Arco operates its own platform, Spark. Figure I-2 shows the locations of these platforms and their related pipeline connections.

McArthur River. This is by far the largest known oil field in the Cook Inlet area, accounting for over half of the State's current total oil production. It was unitized in 1967 with Union as the operator. Ten leases are included in the unit and Union, Marathon, Arco, Amoco, Phillips, Skelly and Socal all have interests in it. Confusingly,

this unit is called the Trading Bay Unit even though it involves only the McArthur River field and not the Trading Bay field.

McArthur River field has been developed from three offshore platforms. To the north is King Salmon, with Arco as unit suboperator; in the middle is Grayling, operated by Union; and in the south is Dolly Varden, operated by Marathon as unit suboperator. As unit operator, Union supervises operations for all three platforms to some extent. Figure I-2 shows the locations of these platforms and their related pipelines.

The common carrier pipelines. None of the pipelines linking offshore platforms to onshore production facilities is a common carrier. However, there are two common carrier pipeline systems serving the Cook Inlet area.

Kenai Pipe Line Company, owned equally by Socal and Arco, is operated by Socal to provide common carrier transportation for crude oil on the east side of the Cook Inlet. There are two branches to the pipeline, one running from Swanson River to the Nikiski marine terminal and the other running to the terminal from the Shell and Amoco production facilities at East Forelands (see Figure I-1 on page I-5). The tariff to move oil from the point where it is metered into the pipeline to ships at the marine terminal is the

same for each of these branches - currently about eight cents per barrel. This tariff has varied from time to time, but while there have been two branches to the pipeline, the tariff has been the same for each branch.

Cook Inlet Pipe Line Company was originally owned by Marathon (20%), Union (20%), Arco (20%), Mobil (20%) and Cities Service (20%). On March 6, 1970, Cities Service sold its interest in the pipeline to Union and Marathon equally, raising their shares to 30% each. The pipeline is operated by Mobil, providing common carrier transportation for crude oil on the west side of Cook Inlet from the onshore production facilities of Arco and Mobil near Granite Point, past the Union-Marathon Trading Bay production facility, to the Drift River Terminal (see Figure I-1 on page I-5). The tariff for moving crude from the production facilities at Granite Point or from the Union-Marathon Trading Bay production facility is currently \$0.07 per barrel. A charge of \$0.155 per barrel is charged for terminalling the oil and moving it from the terminal to ship's rail at Drift River. The total tariff of \$0.225 to get oil to ship's rail at Drift River is the same regardless which production facility the shipped oil comes from.

2. Scope of Current Cook Inlet Production. Approximately 780,000 Mcf of natural gas are produced daily in the Cook Inlet area. This gas production is of two types: gas

well gas (which comes from wells that do not yield any crude oil) and casinghead gas (which is recovered from oil wells in association with the oil). The gas well gas from the fields in the Cook Inlet area is "dry," consisting chiefly of methane with little trace of heavier hydrocarbon gases (i.e., natural gas liquids). On the other hand, the casinghead gas, with its appreciable amounts of natural gas liquids, is "wet."

Of the 780,000 Mcf total average daily gas production, some 350,000 Mcf is casinghead gas. However, this figure is somewhat misleading since nearly 300,000 Mcf are produced in the Swanson River oil field. Almost all of Swanson River gas is re-injected into the reservoir to maintain pressure and enhance the oil recovery.

To illustrate the magnitude of the gas production in relation to the oil production in Cook Inlet, the energy represented by both should be compared. The 172,000 barrels of oil produced each day from Cook Inlet area fields contain about one trillion British thermal units (Btu) of energy, while the gas production that is not re-injected into the ground is the equivalent of about half a trillion Btu. Thus, in terms of Btu energy content, Cook Inlet gas production is about half that of Cook Inlet crude oil production.

3. Geography of Present Gas Well Gas Production. Four major Cook Inlet Basin gas fields are: Kenai, Beluga River, North Cook Inlet and McArthur River. The first two are predominately located on federally-leased uplands and partially on State lands, including tide and submerged lands. Some private land (homesteads) is included in the Kenai field. North Cook Inlet and McArthur River are both entirely on State submerged lands in the Inlet.

Kenai field. The Kenai field's estimated recoverable reserves are 2.4 to 3 trillion cubic feet. Union is the field operator and, with Marathon, owns the bulk of the production. Arco and Socal have small interests in some of the production from the Kenai field.

Two gas pipelines run from Kenai field. One, owned by Alaska Pipeline Company, runs east and north across Turnagain Arm to Anchorage, where the gas is sold and distributed. The other line runs north, through the town of Kenai, to the industrial area at Nikiski. This second line is owned by Union and Marathon. Figure I-3 shows the routes of these pipelines and the location of the Kenai gas field.

Beluga River field. With estimated recoverable reserves of approximately 1 trillion cubic feet, the Beluga River gasfield is operated by Socal for its partners in the field, Shell and Arco. Short pipelines bring the gas to the Beluga

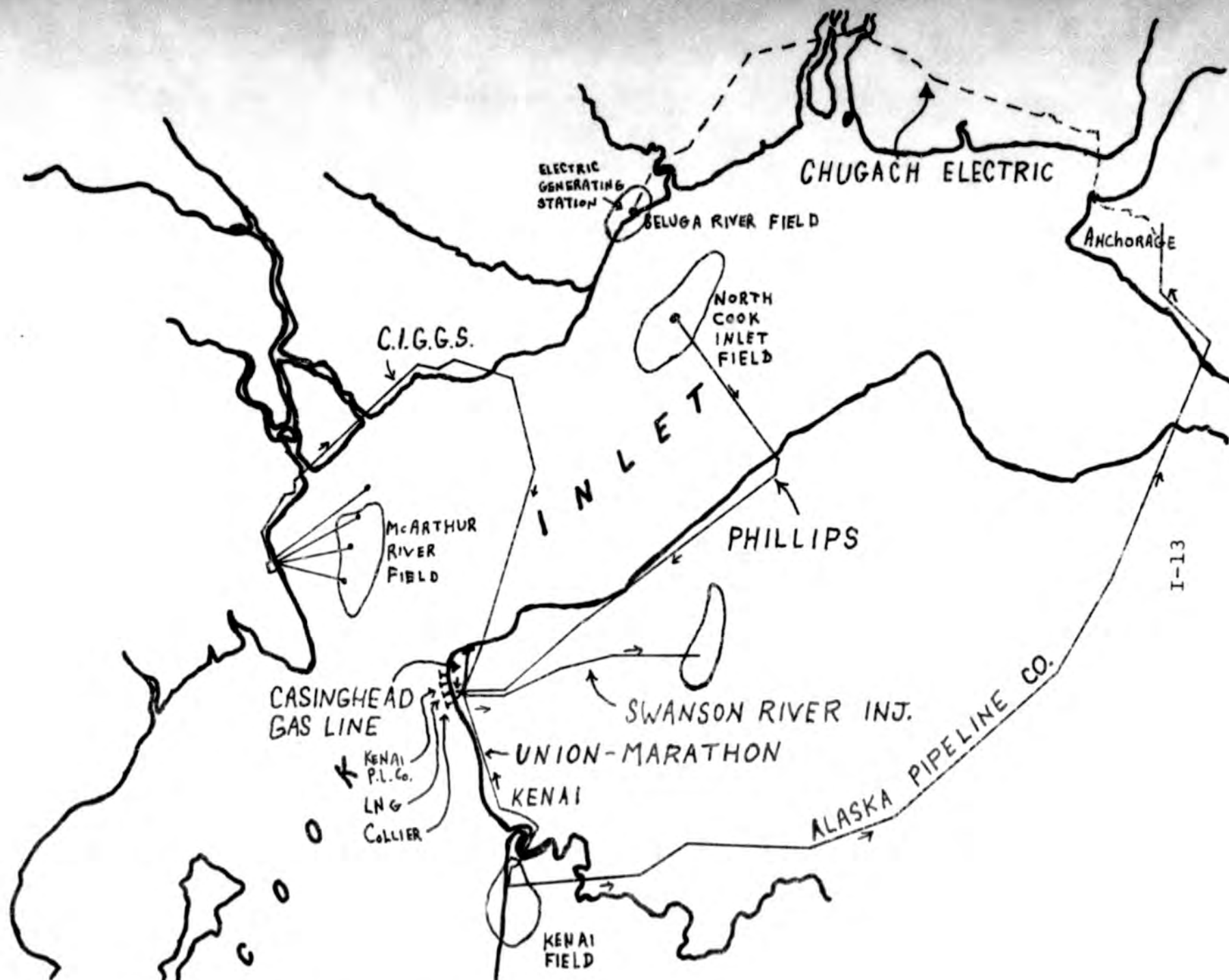


Figure I-3 Cook Inlet Gas Fields and Gas Pipelines

River electrical generation plant owned by Chugach Electric Association, which generates electricity for Anchorage. Figure I-3 shows the location of the gas field and the power station, as well as the route of the transmission line to Anchorage.

North Cook Inlet field. North Cook Inlet gas field is owned and operated by Phillips Petroleum Company. The field has been developed by wells directionally drilled from an offshore platform. Reserves are estimated at 1.5 to 2 trillion cubic feet. Twin subsea pipelines run from the platform directly to shore, where they become a single, larger line running generally parallel to the coast to Nikiski. Again, Figure I-3 shows the location of the field, the platform and the pipelines.

McArthur River field. The fourth field, McArthur River, is known now as an oil field. However, about one trillion cubic feet of gas are in a gas reservoir in the same large geologic structure. Development of the field so far has been primarily for the oil reserves. Comparatively little gas well gas (about 17,000 Mcf a day) is now being produced and is used in the oil production operations. Figure I-3 also shows the location of McArthur River field.

4. Present Marketing of Gas Production. The following summarizes the various gas sales in the Cook Inlet area.

Beluga River field. All gas being sold now from this field is purchased by Chugach Electric Association, Inc. under a contract running through 1997. Some 373 billion cubic feet of reserves were committed to the contract. In 1976 the price was 16.2 cents per Mcf, with an adjustment based on the heat content of the gas. From 1977 to 1987 the base price will move upward, either to 27 cents or to the price then being paid by Pacific Lighting for Beluga River gas, whichever is higher, in accordance with a formula based on delivery volumes. Thereafter it will rise 1 cent every other year.

Pending approval by the FPC, Pacific Lighting has a commitment of most of the remainder (600 billion cubic feet) of Beluga River reserves for its proposed LNG plant. The proposed wellhead price will be considerably greater than what Chugach Electric now pays, although Chugach's price will catch up by 1987.

Kenai Field. A total of 400 billion cubic feet of gas is being "rented" from Union and Marathon by Socal and Arco for the Swanson River pressure maintenance program. Most of the gas has already been delivered via the Union-Marathon pipeline from the field to Nikiski and thence to Swanson River field via a pipeline paralleling Kenai Pipe Line Company's oil line. Deliveries are down to about 10,000,000

Mcf a year. The rental is 8.1 to 8.9 cents per Mcf, depending on delivery pressure. When the oil production operations at Swanson River cease, the gas recovered during "blowdown" will be returned to Union and Marathon.

Besides renting gas, Union and Marathon have jointly sold gas to the City of Kenai (30 billion cubic feet committed) and to Alaska Pipeline Company, the transmission company that brings the gas to Anchorage for retail distribution by its affiliate, Alaska Gas and Service Company. Reserves committed to Alaska Pipeline were increased in 1972 to 550 billion cubic feet. The contract now provides for a base price of 24 cents for 1976-80 and 27 cents for 1981-85. To those prices is added, as of July 1, 1975, a variable "special deliverability charge" of 19.5 cents per Mcf, which changes annually in proportion to changes from the November 1974 level of the Wholesale Price Index for all commodities. The amended contract also specifically provides that any reserves tax will be passed on to Alaska Pipeline pro rata.

Owned by Union Oil Company, Collier Carbon and Chemical Corporation operates the world's largest ammonia-urea plant at Nikiski and its capacity is being doubled. Union originally committed 450 billion cubic feet of reserves to Collier, delivered through the Union-Marathon pipeline from the field to Nikiski. Reportedly, the commitment has been increased to 1038 billion cubic feet. The price has been 17

cents per Mcf, to be raised by 1 cent at the end of 1978 and every five years thereafter for the duration of the contract.

Marathon is supplying 30 percent of the gas going into the Phillips-operated LNG plant at Nikiski for sale to Japan.

North Cook Inlet field. The other 70 percent of the gas for the LNG plant comes from the North Cook Inlet Field, which Phillips operates. All the LNG is shipped to Japan. The price for gas landed in Tokyo is \$1.95 per million Btu (approximately one Mcf), up from the original price of \$0.52. The contract calls for gas to be delivered to Japan equal to a total of 743.265 trillion Btu. Marathon reports that 1.23 cubic feet of production shrinks to 1 cubic foot of delivered gas. Using a heat content of 1007 Btu per cubic foot (as reported by Marathon), the contract commits 908 billion cubic feet of reserves: Marathon's 30 percent share from the Kenai field is 272 billion, Phillips' share from North Cook Inlet is 636 billion. Phillips used to sell small volumes of gas to the Tesoro-Alaskan refinery and may still do so.

McArthur River field. At present there is no production of gas well gas from this field for commercial sale, although almost 11 percent of its estimated reserves have been committed to Pacific Lighting's proposed LNG plant. Some gas

well gas is produced for use in the oil production operations of the Trading Bay Unit.

Casinghead gas. Formerly the casinghead gas produced in association with crude oil was flared. As oil production grew and the volumes of flared gas became large, concern developed over this practice. A valuable resource was being lost, and residents on both sides of the Inlet could see a possible source of inexpensive fuel literally going up in smoke. After a number of hearings, the Oil and Gas Conservation Committee imposed a no-flare order for the Cook Inlet oil fields. Small safety flares were permitted, but most of the casinghead gas had to be put to beneficial use.

To comply with this order, the Cook Inlet Gas Gathering System (CIGGS) was built to gather casinghead gas from onshore production facilities on the west side of the Inlet and transport it to Nikiski, where most of the gas goes to Collier Carbon's urea plant and some goes into the gas line running out to Swanson River for the repressurization program (see Figure I-3). A second pipeline from the East Forelands oil production facilities brings casinghead gas from Middle Ground Shoal to Collier Chemical's plant (see Figure I-3).

C. NORTH SLOPE

Prudhoe Bay field. The Prudhoe Bay field is large. The main reservoir extends approximately 32 miles from east to west and more than 13 miles from north to south. Its oil reserves are estimated to be more than twice as much as the remaining oil reserves of the next four largest U.S. fields combined. Its gas reserves, in fact, represent almost as great an energy resource as the combined remaining oil reserves of those four fields. 1/

The field is mostly onshore, on lands selected by the State under the Statehood Act. The offshore portion of the field is on land that came to the State with statehood.

At present it is proposed that the main reservoir will have two operators: Arco will operate the eastern portion and BP the western portion. Pump Station 1 - the point where the oil will begin its passage through the Trans Alaska Pipeline to Valdez - is located on the dividing line between the two operating areas (see Figure I-4). Each operator will have its own housing facilities for the personnel operating the field.

The production operations for the two areas of the field will be quite similar. Wells will be directionally drilled from a number of drill sites (pads) in each operating

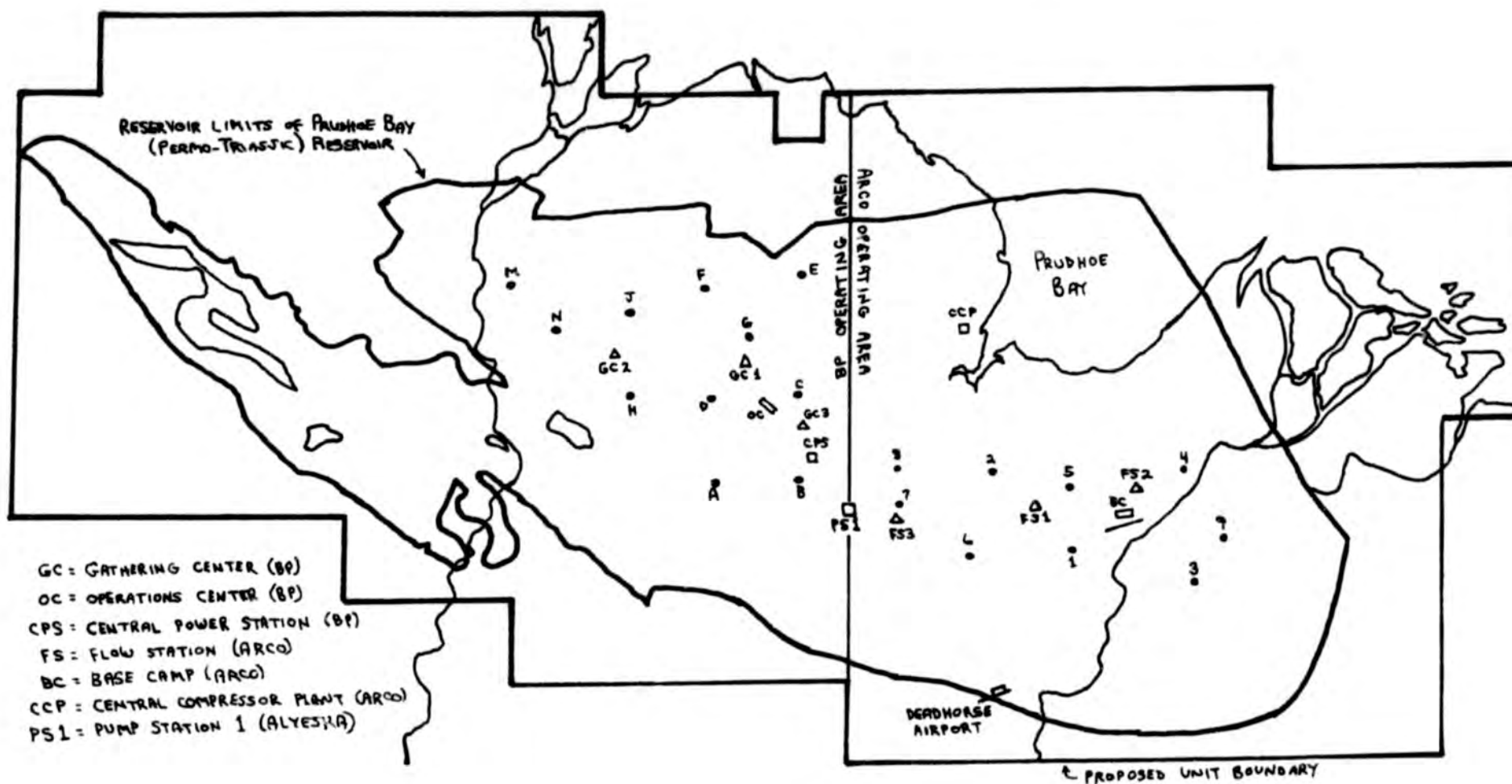


Figure I-4 Prudhoe Bay Field

area of the field. The recovered liquids and associated gases will move from individual drill sites to a gathering center or flow station.

At each flow station (gathering center) the liquid stream will be treated to remove basic sediments and water and to separate the associated gas. The crude oil will then move from the gathering centers (flow stations) through large lines to Pump Station 1.

Both Arco and BP plan to have three flow stations (gathering centers) operating when the field is producing at 1.5 to 1.6 million barrels a day. Only two on each side will be needed to produce the 1.2 million barrels a day that will be filling TAPS by the end of this year.

While the two operators may generally conduct their production operations separately, there is a degree of built-in interdependence. The gas recovered from or in association with the crude oil from both sides of the field will be processed at the Arco-operated Central Compression Plant. Until a gas pipeline is built, most of this gas will be compressed and re-injected back into the reservoir to maintain pressure. Some of the gas will go to Alyeska to fuel the first four TAPS pump stations and some will fuel the Central Power Station, which BP operates to provide electricity for operations on both sides of the field (see Figure I-4).

In addition to the main oil pool, three other reservoirs have been identified in the proposed unit agreement for possible future development. These are the Lisburne and Kuparuk oil pools and the North Prudhoe Bay (Permo-Triassic) Reservoir. The extent of any of these reservoirs has not yet been fully determined and their potential is still unclear. No development plans have been announced for any of these reservoirs, nor has anyone been proposed as an operator for them.

Other North Slope fields. To date a number of other oil and gas fields have been discovered on the North Slope. All are very much smaller than the Prudhoe Bay field, and only one of them is producing. The one producing field, the South Barrow gas field, is operated by the U.S. Navy for its facilities near Barrow. Gas is also sold to Barrow residents (see Figure I-5). Production during November 1976 averaged 2562 Mcf a day. 2/

There are two other known fields in the National Petroleum Reserve (Naval Petroleum Reserve No. 4): the Simpson oil field on the Arctic coast and the Umiat oil field near the Colville River (see Figure I-5). Neither of these seems large enough to justify the investments needed to develop them and to transport the production to market. An exploration effort to "prove up" the Reserve has been begun and is continuing, but to date it has not met with much success.

Between the Colville and Canning Rivers are four fields besides Prudhoe Bay: the Simpson Lagoon oil field, the Ugnu oil field, the East Umiat gas field, the Kavik gas field and the Kemik gas field (see Figure I-5). These fields are also too small to produce at this time.

Chapter I - Footnotes

- 1/ The largest U.S. fields according to remaining oil reserves were, as of January 1976:

Prudhoe Bay	9.6 billion
East Texas	1.69 billion
Elk Hills	1.05 billion
Santa Ynez Unit	1.00 billion
Yates	0.98 billion
TOTAL	4.72 billion

"Here are the Big U.S. Reserves," Oil & Gas Journal (January 26, 1976), pp. 118 - 120. The energy represented by 27 billion cubic feet of gas - using 1000 Btu to the cubic foot and 6,000,000 Btu to a barrel of oil - equals that of 4.5 billion barrels of oil.

- 2/ State of Alaska, Department of Natural Resources Division of Oil and Gas Conservation, Bulletin (January 1977), pp. 13 - 14.

CHAPTER II. ALASKA'S PRESENT TAX STRUCTURE

A. OIL AND GAS PROPERTIES PRODUCTION TAX

One of the taxes imposed by the State on the oil and gas industry is the Oil and Gas Properties Production Tax ("production tax," for short). This is a tax on the activity of producing oil and gas in Alaska. Its structure has changed considerably since its enactment in 1955 during the First Extraordinary Session of the Twenty-Second Territorial Legislature. Then it was a simple one percent of value, for both oil and gas production. 1/

During the period of the major oil and gas discoveries onshore and offshore in the Cook Inlet area, the production tax remained unchanged. However, the devastating Fairbanks flood of 1967, coming as it did only three years after the Good Friday earthquake, prompted the First Special Session of the Fifth State Legislature to enact that year a one percent Disaster Severance Tax (AS 43.43.110-.160) in addition to the regular production tax. 2/

The next year saw the first change in the production tax, an increase in rate to three percent. 3/ In conjunction with the Disaster Severance Tax, the total State taxes on oil and gas production came to four percent. This combined rate was maintained in 1970 for gas production only, when the Disaster Severance Tax was repealed and the production tax rate for gas was raised to four percent. 4/

The 1970 legislation also marked the departure of oil taxation from gas taxation. While the overall tax rate on gas remained at four percent, a "stair stepped" rate structure was established for oil, based on the productivity of individual wells. The more a well produced, the greater the tax became: three percent on the well's first 300 barrels a day, five percent on its next 700, six percent on its next 1500 and eight percent on any production in excess of 2500 barrels a day. 5/

The oil tax structure was further modified by the enactment of a cents-per-barrel tax in 1972. This alternative tax was "stair stepped" to correspond to the "stair steps" of the percentage tax: 45.8 cents per barrel for a well's first 300 barrels a day, 51.1 cents for its next 700, 53.8 cents for its next 1500 and 59.1 cents for its production over 2500 barrels a day. Noteworthy is the 5.7 percent reduction in these cents-per-barrel rates that was scheduled for production beginning July 1, 1980. 6/

The cents-per-barrel tax also interrelated to royalty payments made to the State. 7/ A credit, equal to the royalty payment made to the State, was allowed against the cents-per-barrel rates in determining the net cents-per-barrel tax due. For purposes of the "royalty credit," the State's royalty share was declared to be one-eighth of the oil produced.

If the cents-per-barrel tax, after allowing the "royalty credit," was greater than the percentage-of-value tax, the net cents-per-barrel tax was the tax to be paid. If the percentage-of-value tax was greater, the production tax was payable on that basis. 8/ The effect of this was to set a "floor" on the State's combined production tax and royalty revenues that corresponded to a price of \$2.65 a barrel. 9/ If the price declined below that, the "royalty credit" provision offset the royalty income "lost" as the result of the lower price.

These new production tax provisions, together with several other enactments of the 1972 Session, became the subject of litigation brought by a number of oil companies. 10/ In its First Special Session in 1973, the Eighth State Legislature effectively settled that litigation by enacting eight pieces of legislation, including one amending the production tax. 11/

This amendment repealed the "royalty credit" and changed the "stair steps" and tax rates for both the cents-per-barrel and percent-of-value provisions to their present form. Now the well's first 300 barrels a day are taxed at five percent or 16.875 cents a barrel, the next 700 at six percent or 20.25 cents a barrel and everything over 1000 at eight percent or 27 cents a barrel. The tax to be paid is still the higher of the two.

Unlike the earlier version of the cents-per-barrel tax, the present one has two mechanisms that vary the cents-per-barrel rate. The first of these is a "gravity factor." Based on the API gravity of the oil, the rates specified above are increased or decreased by two percent for each degree above or below 27° API gravity. 12/ Thus a complete schedule of cents-per-barrel rates can be constructed for various gravities of crude oil.

The second mechanism to vary the cents-per-barrel rates is an "escalator" based on changes in the Wholesale Price Index for crude oil, which the Bureau of Labor Statistics of the U.S. Department of Labor publishes each month. Changes in the Index change proportionally the entire schedule of cents-per-barrel rates that could be prepared for different gravities of crude oil. Each month the Department of Revenue notifies all oil production tax taxpayers of the preceding month's change (if any) in the Index and presents them with the correspondingly changed schedule of cents-per-barrel rates for various gravities of oil, which the taxpayers apply to the following month's production. 13/

At present, an appeal is pending before the Alaska Supreme Court regarding which crude oil Wholesale Price Index should be used as the base from which changes are to be measured. The statute provides:

Changes in [cents-per-barrel] tax rates will be computed based on changes in the Wholesale Price Index occurring after January 1, 1974 and will not include changes in the Wholesale Price Index prior to January 1, 1974.

AS 43.55.015(c) (emphasis added). By regulation the Department of Revenue adopted the Index for December 1973 as the base from which changes are measured. The taxpayers have sued, contending that the January 1974 Index should have been used.

Pending the outcome of the taxpayers' appeal, the Department of Revenue has continued to post monthly cents-per-barrel rate schedules on the basis of changes from the December 1973 Wholesale Price Index. The December 1976 Index, which is used to compute the rates applicable to February 1977 production, is 180.8 percent of the December 1973 Index, so the February rates of 30.51 cents, 36.62 cents and 48.83 cents for 27° API gravity oil are nearly 81 percent greater than the base rates set out in the statute.

The following example illustrates how the present production tax operates:

Example

It is March 1977 and production taxes for February production are coming due. ABC Oil Company has a lease on State lands in Cook Inlet. Production moves to the west side of the Inlet, where it is transported to ship's rail at Drift River by Cook Inlet Pipe Line Company. ABC Oil's lease has three producing wells; and in February 1977 well 1 produced 6020 barrels of 34° API gravity oil; well 2 produced 10,520 barrels of 35° API gravity oil and 25,600 barrels of 36° API gravity oil during the month; and well 3 had 21,700 barrels

of 33° API gravity oil. Federal price ceilings for "old oil" from the portion of Cook Inlet that includes ABC Oil's lease are \$4.825 a barrel for 33°, \$4.855 for 34°, \$4.885 for 35° and \$4.915 for 36° oil. Assume that "new oil" is allowed a ceiling \$6.10 above the "old oil" price. ABC Oil had a total of 3360 barrels of "new oil," and all the rest of ABC Oil's production was "old oil." It is assumed for purposes of this example that the controlled prices represent the taxable value.

Percent-of-value tax. To compute the production tax on the percent-of-value basis, it is first necessary to find the average price of the production. This is done by finding the total value of the production and dividing by the number of barrels produced:

<u>Gravity</u>	<u>Price</u>	<u>Production in Month</u>	<u>Value</u>
33°	\$4.825	21,700	\$104,702.50
34°	4.855	6,020	29,227.10
35°	4.885	10,520	51,390.20
36°	4.915	25,600	125,824.00
		<u>63,840</u>	<u>\$311,143.80</u>
"New Oil" Premium:	6.10	3,360	<u>20,496.00</u>
TOTAL VALUE			\$331,639.80

The average price is \$331,639.80 divided by 63,840 barrels, or \$5.1949 a barrel.

The next step is to find the number of barrels that fall into the three "stair steps." To do this, each well's average daily production in February must first be calculated:

Well 1: $6,020/28 = 215 \text{ B/D}$
 Well 2: $10,520$
 $25,600$
 $36,120/28 = 1290 \text{ B/D}$
 Well 3: $21,700/28 = 775 \text{ B/D}$

Next the total number of daily barrels in each category is found and multiplied by the number of days in the month to yield the total production in each "stair step" for the month. Since the State's royalty is exempt and pro-rated among the three "steps," the total production for the month in each "step" is multiplied by 7/8 (0.875).

<u>Well</u>	<u>0-300</u>	<u>301-1000</u>	<u>1000+</u>
1	215	0	0
2	300	700	290
3	300	475	0
	<u>815</u>	<u>1175</u>	<u>290</u>
	x 28	x 28	x 28
	<u>22,820</u>	<u>32,900</u>	<u>8,120</u>
	x .875	x .875	x .875
	<u>19,967.5</u>	<u>28,787.5</u>	<u>7,105.0</u>

Using these totals of taxable production in each "stair step," the percent-of-value tax may be calculated by multiplying the total in each "step" times the average price of \$5.1949 a barrel, and then applying the appropriate tax rate:

$$\text{0-300: } 19,967.5 \times \$5.1949 \times 0.05 = \$ 5,186.46$$

$$\text{301-1000: } 28,787.5 \times 5.1949 \times 0.06 = 8,972.89$$

$$\text{1000+: } 7,105.0 \times 5.1949 \times 0.08 = \underline{2,952.78}$$

TOTAL PERCENT-OF-VALUE TAX \$17,112.13

Cents-per-barrel tax. At this point the taxpayer is about half finished, since the cents-per-barrel tax must also be calculated in order to determine which tax is payable. This calculation is slightly more complex because the production must be allocated separately by API gravity into each of the three "stair steps."

First of all, the weighted average API gravity must be found for each well's production during the month. Wells 1 and 3 are simple since their production was all 34° and 33°, respectively. Well 2, however, had both 35° and 36° production; so the number of barrels of 35° gravity is multiplied by 35, the number of barrels of 36° gravity is multiplied by 36, and the sum of the two products is divided by the total number of barrels. The quotient is the gravity: the fractional part (to the right of the decimal point) is ignored; there is no rounding:

$$\begin{array}{rcl} \text{Well 2: } 10,520 \text{ bbl.} \times 35 & = & 368,200 \\ 25,600 \text{ bbl.} \times 36 & = & 921,600 \\ \hline 36,120 \text{ bbl.} & & 1,289,800 \end{array}$$

$$1,289,800 / 36,120 = 35.71^\circ$$

Weighted Average API Gravity = 35°

The next step is to array the production, by API gravity, into the appropriate "stair steps." This could be done like this:

		<u>Well 1</u> <u>(B/D)</u>	<u>Well 2</u> <u>(B/D)</u>	<u>Well 3</u> <u>(B/D)</u>	<u>Total</u> <u>(B/D)</u>
33°	0-300:	0	0	300	300
	301-1000:	0	0	475	475
	1000+:	0	0	0	0
34°	0-300:	215	0	0	215
	301-1000:	0	0	0	0
	1000+:	0	0	0	0
35°	0-300:	0	300	0	300
	301-1000:	0	700	0	700
	1000+:	0	290	0	290
36°	0-300:	0	0	0	0
	301-1000:	0	0	0	0
	1000+:	0	0	0	0

Ordinarily the taxpayer would simply multiply the entries in the "Total" column by the number of days in the month (28), then multiply by 7/8 (0.875) to find the taxable production, and finally apply the appropriate cents-per-barrel rates posted by the Department of Revenue. However, to illustrate the calculations done for the taxpayer by the Department in issuing its cents-per-barrel rate schedule, the tax for ABC Oil will be calculated the long way.

The base rates for 27° oil, as escalated in proportion to changes in the crude oil Wholesale Price Index, are \$0.3051, \$0.3662 and \$0.4883 for February. These are raised or lowered two percent per degree above or below 27°. The factor doing this is called the "gravity factor." The cents-per-barrel tax may then be calculated as described above, using the escalated base rates and the appropriate "gravity factors" instead of the Department's rate schedule.

		<u>Total</u> <u>(B/D) X 28</u>	<u>Taxable</u> <u>7/8 = Bbls.</u>	<u>Base</u> <u>Rates</u>	<u>Gravity</u> <u>Factor</u>	<u>=</u>	<u>Tax</u>
33°	0-300:	300	7,350.0	\$0.3051	1.12		\$ 2,511.58
	301-1000:	475	11,637.5	0.3662	1.12		4,773.05
	1000+:	0	0	0.4883	1.12		0
34°	0-300:	215	5,267.5	0.3051	1.14		1,832.11
	301-1000:	0	0	0.3662	1.14		0
	1000+:	0	0	0.4883	1.14		0
35°	0-300:	300	7,350.0	0.3051	1.16		2,601.28
	301-1000:	700	17,150.0	0.3662	1.16		7,285.18
	1000+:	290	7,105.0	0.4883	1.16		4,024.47
TOTAL CENTS-PER-BARREL TAX							\$23,027.68

The percent-of-value calculation yielded a tax of \$17,112.13, less than that under the cents-per-barrel approach. Therefore, the tax due is the cents-per-barrel tax of \$23,027.68. If ABC Oil has any remaining EDIC from previous reserves tax payments, the actual tax payment made by ABC Oil will be \$23,027.68 minus the smaller of (1) the remaining EDIC and (2) \$11,513.84 (50 percent of \$23,027.68).

B. OIL AND GAS REGULATION AND CONSERVATION TAX

Enacted during the First Special Session of the Eighth State Legislature in 1973, 14/ the Oil and Gas Regulation and Conservation Tax ("conservation tax") is imposed on oil production only. It is a non-escalating tax of one-eighth of a cent per barrel and has no "stair steps." As with the production tax, production attributable to a royalty interest of the State, the United States or other tax-exempt entity is not taxed.

The payment and administration of the conservation tax are done in the same manner as the production tax.

C. OIL AND GAS EXPLORATION, PRODUCTION
AND PIPELINE TRANSPORTATION PROPERTY TAX

General description. In its First Special Session in 1973, the Eighth Legislature also passed the first statewide ad valorem tax on oil and gas properties. 15/ The tax as enacted not only set up a State-administered tax on specified categories of oil and gas property, but also set limitations on the power of municipalities to impose taxes on oil and gas properties in general. 16/

The oil and gas exploration, production and pipeline transportation property tax ("property tax") is a levy of 20 mills on certain categories of oil and gas hardware properties throughout the state. These accessible properties include: exploration properties, such as seismic equipment and drilling rigs; production properties, such as wells, platforms and field gathering lines; and pipeline transportation properties, such as pipelines, pump stations and integrated terminal facilities. Categories of properties which are excluded by definition from the property tax are oil refining property, gas processing property, oil and gas retail distribution property, and any interest or rights to produce oil and gas (such as oil and gas leases).

A few types of oil and gas properties are specifically

excluded from the coverage of the tax even though they fall within the definitions of exploration, production and pipeline transportation. For example, pipelines operated as utilities and regulated by the Alaska Public Utilities Commission are excluded from the operation of the tax.

Municipalities may also levy and collect property taxes on the same properties as the State, although the actual assessment of the properties is made by the Department of Revenue. A municipality choosing to levy taxes on these properties may do so only at the same millage as it taxes other properties in its boundaries. In addition, there are specific limitations that restrict the amount of taxes that a municipality may ordinarily collect.

One limitation provides that a municipality may not levy taxes which will result in its total property tax revenues exceeding \$1500 per capita for its residents. The other limitation provides that the total assessed valuation of taxable property in the municipality will not exceed the product of 225 percent of the average per capita assessed full and true value of property in the State multiplied by the number of residents in the municipality. 17/ The average per capita assessed full and true value of property in the State is reported by January 15 each year to each municipality by the Department of Revenue.

The first limitation places a ceiling on the amount of tax while the other limits the total amount of assessed value. Each municipality taxing oil and gas properties must choose by February 1 of each year which of the two limitation methods that it will be operating under and report the choice to the Department of Revenue. 18/ In all cases municipalities have chosen the \$1500 per capita (\$1000 before 1976) limitation.

Those municipalities which have imposed property taxes pursuant to AS 29.53.045 include:

North Slope Borough
Fairbanks North Star Borough
Matanuska-Susitna Borough
Kenai Peninsula Borough
Municipality of Anchorage
City of Kenai
City of Soldotna
City of Fairbanks

It is also anticipated that the City of Yakutat will impose a property tax on these properties in the coming year.

In addition to the limitations placed on the property taxation of the specified properties by municipalities, the state property tax statute also places other limitations on municipal taxing powers of oil and gas properties generally. For example, municipalities are prohibited from taxing property rights to produce oil and gas, such as oil and gas leases.

Taxes on the sale or use of gas or unrefined oil or the sale or use of property, or the sale or use of services used in association with the property (except for a retail sales tax on the first \$1000 of each sale) are also prohibited. In addition, municipalities are also prohibited from imposing taxes measured by income from oil and gas properties or from imposing any other tax or fee pertaining to the oil and gas properties or associated services. 19/

The municipal tax paid on the oil and gas properties assessed by the State may be claimed as a credit by the taxpayer against the State tax on the same properties. If the municipal tax is not paid until after the due date of the State tax payment (June 30), the taxpayer must pay the full amount of the State tax and may apply for a refund equal to the municipal tax when it has been paid. 20/ By regulation the Department has interpreted these statutes so as to exclude from any refund or credit municipal property taxes levied and collected under AS 29.53.055 in excess of the "\$1500 per capita" and "225 percent" limitations described above. 21/ The validity of this regulation has been challenged in the courts and is not yet adjudicated.

Assessment of taxable properties. Taxable oil and gas properties are assessed or valued under several techniques, depending on the category of the property. These are market value, replacement cost, actual cost, and economic value.

Sometimes a property may be put to several different uses during a particular year, and accordingly the property may actually fall into two different categories of property. In those situations the property is valued on the basis of the prescribed valuation technique for the category in which it falls for the majority of its use. For example, a drilling rig may be used for both exploration purposes and production purposes during any particular year. If it was used more for exploration work than for production work, it would be valued as exploration property.

In discussing the valuation method for each category of oil and gas properties, it is helpful to illustrate the method by an example. Therefore a hypothetical example (ABC Oil Company) is carried through all categories of property.

Example

ABC Oil is involved in exploration, production, and pipeline transportation of unrefined oil in the State of Alaska. The company made a discovery in 1969 and has since developed a four-well field that is producing 1200 barrels of oil per day. The oil produced from this field flows through a company-owned onshore production facility and is then transported through a common carrier pipeline owned by XYZ Pipeline Company to a loading facility. ABC Oil also owns and operates a drilling rig for exploration, development and well maintenance work. The field and facilities have been in operation since January 1, 1970, and current engineering studies indicate the field will continue to be economically productive until July 1, 1981. This entire operation is located in a municipality that currently has a tax levy of eight mills.

Exploration property is valued on the basis of its market value, which is defined under the statute as the

estimated price which the property would bring in an open market and under the then-prevailing market conditions in a sale between a willing seller and a willing buyer, both conversant with the property and with prevailing general price levels. 22/

ABC Oil's exploration property during the year is the drilling rig referred to earlier. It was purchased new by ABC Oil in 1968 and shipped to Alaska. Since then the company has added components to the original drilling rig. To determine the market value as of January 1, 1977, the State would examine the rig's actual cost, replacement cost, and comparable sales as follows:

The following table shows the rig's actual costs, as well as today's replacement cost with straight-line depreciation over a ten-year life, to a maximum depreciation of 60 percent (40 percent good):

<u>Item</u>	<u>Cost</u>	<u>Date</u>	<u>Factor</u>	<u>Trended Cost</u>	<u>% Good</u>	<u>Indicated Value</u>
Drilling Rig	\$1,352,500	1968	1.81	\$2,448,025	.40	\$979,210
Cooler	2,295	1969	1.73	3,970	.40	1,588
Rig Mats	62,650	1970	1.61	100,868	.40	40,347
Drill Pipe	22,750	1969	1.73	39,358	.40	15,743
Drill Pipe	3,500	1970	1.61	5,635	.40	2,254
Drill Pipe	6,475	1973	1.40	9,065	.60	5,439
Drill Pipe	<u>12,720</u>	1975	1.06	13,483	.80	<u>10,787</u>
Total: actual cost	\$1,462,890					
Total: trended cost less depreciation						\$1,055,368

These results would then be compared with appropriate market data to determine their relative reliability. Suppose a review of drilling rig sales in the area reveals that two rigs of comparable capacity, age and condition have sold in the past two years for approximately \$1,000,000 each. The terms of these sales would be examined, if possible, to confirm their appropriateness for comparison. In this case they are comparable and would indicate that the depreciated, trend cost approach results in a more reasonable estimate of market value than actual cost.

Thus, a value of \$1,055,368 would be assessed to the exploration drilling rig.

Production property is valued on the basis of its replacement cost, less depreciation based on the economic life of proven reserves. 23/ Replacement cost is the price which a person would have to pay at current prices to replace a particular property that would do the job just as well as the replaced property. This value is then depreciated over the life of the reserves that are serviced by the production property.

ABC Oil's production property consists of its onshore production facilities and four oil wells, two of which have dual completions instead of single completions. The original onshore production facilities were constructed in 1969 with additional equipment added through the years. The remaining economic life of the oil field is 4 1/2 years. The following shows how this property would be assessed on the basis of replacement cost, with depreciation based on the remaining economic life of the field and the total useful life of facilities and equipment.

Replacement cost is determined by factoring the historic cost upward to compensate for the effect of past inflation. This trended cost is then depreciated to current value based on the remaining economic life of the field in relationship to the total useful life of the property (elapsed life plus remaining economic life). The table shows how this would be done for ABC Oil's onshore production facilities:

<u>Item</u>	<u>Date</u>	<u>Cost</u>	<u>Factor</u>	<u>Trended Cost</u>	<u>Remaining Life/Total</u>	<u>Assessed Value</u>
Facility	1969	\$1,375,000	X 1.73	\$2,378,750	X 4.5/12.5 =	\$856,350
2 Tanks	1971	162,300	X 1.51	245,073	X 4.5/10.5 =	106,030
4 Air Comp.	1973	2,250	X 1.40	3,150	X 4.5/ 8.5 =	1,670
2 Pumps	1975	11,750	X 1.06	12,455	X 4.5/ 6.5 =	8,620
Total Replacement Cost						\$971,670

ABC Oil's four oil wells in the field are also valued as production property. The taxable value is determined

by trending the tangible cost of each of the four wells, (the intangible drilling expenses and exploration expenses are exempt under AS 43.56.020(5)) plus a factor for installation of tangibles. After arriving at a total average cost per foot for each type well, that figure is applied to the actual plugback depth for each well. To arrive at assessed value an economic factor is applied which represents the remaining life of the field divided by the total life of the field.

<u>Wells</u>	<u>Trended Installed cost per foot</u>	<u>Plug Back depth</u>	<u>Trended Value</u>	<u>Economic Factor</u>	<u>Assessed Value</u>
2-Single Production (11,500' ea.)	\$34.00	X 23,000'	= \$782,000	X 4.5/11.5	= \$306,000
2-Dual Production (13,500' ea.)	37.00	X 27,000'	= \$999,000	X 4.5/11.5	= <u>390,000</u>
Total Replacement Cost					\$696,900

Thus the total, depreciated replacement cost for both the onshore production facilities and the oil wells is \$1,668,570 (\$971,670 plus \$696,900).

Pipeline transportation property is valued under two different methods. First, until a pipeline begins to transport oil or gas, the pipeline will be valued on the basis of actual costs incurred with respect to the property. 24/ After a pipeline has commenced transporting oil or gas, the pipeline will be valued on its economic value unless the proven reserves of oil or gas indicate an economic life materially shorter than the estimated physical life of the transportation facility. If there is a materially shorter economic life, then the pipeline will be valued on the basis of actual cost reduced by an annual allowance for depreciation over the economic life. 25/

The pipeline transportation property consists of an operating pipeline owned by XYZ Pipeline Company. XYZ Pipeline operates a pipeline which transports oil for ABC Oil, as well as for other oil companies operating in the same field, from their production facilities to the tanker wharf.

Lines, tanks, and tanker wharf were constructed by XYZ Pipeline in 1969 and operation commenced January 1, 1970. Engineering studies indicate the longest economic life of proven reserves served by the pipeline is 4.5 years, or until July 1, 1981.

The two tables below show the indicated value of the property, using first, replacement cost (less depreciation) and, second, capitalized future net income.

It is assumed that the economic life is not materially shorter than the estimated physical life of the transportation facility, so the assessment would be made on the basis of the pipeline's economic value.

The depreciated replacement cost of the pipeline is calculated in a manner similar to that used for ABC Oil's production properties. Actual costs are first trended to today's replacement costs and then depreciated on a straight-line depreciation basis over the economic life of the reserves served by the pipeline.

REPLACEMENT COST ANALYSIS

XYZ PIPE LINE CO.
1-1-77
(In Thousands)

	<u>Year</u>	<u>Cost</u>	<u>Trend Factor</u>	<u>Trended Cost</u>	<u>Depreciation (% Good)</u>	<u>Trended Cost Less Str. Line Depreciation</u>
Lines	1969	\$26,000	1.94	\$50,440	4.5/12.5=.3600	\$18,158
Storage Tanks	1969	16,000	1.94	31,040	4.5/12.5=.3600	11,174
Tanker Wharf	1969	12,000	1.94	23,280	4.5/12.5=.3600	8,381
						\$37,713
Land & R/W	1969	20				50
						\$37,763
TOTAL VALUE						\$37,763

To determine the capitalized value of the pipeline's future net income, throughput estimates are projected annually on the basis of reservoir engineering data for all proven reserves served by the pipeline. Next, the annual gross income is projected, applying the present tariff of \$0.20 a barrel to the annual projected throughput. Operating expenses are then projected and future tax payments estimated. These total costs, plus any anticipated capital expenditures, are deducted from the annual gross income to find the net income for each year. Then, an appropriate deferment (discount) rate is applied to each year's net income to arrive at the present value of each year's net income. The total of these present values is the indicated value of the pipeline under this assessment technique.

CAPITALIZED NET
INCOME ANALYSIS

XYZ PIPE LINE CO.
(In Thousands)

Bbls	1977	1978	1979	1980	1981	1982
Well No. 1	10,000	8,000	6,000	6,000	4,000	1,000
Well No. 2	15,000	15,000	15,000	9,000	9,000	2,000
Well No. 3	20,000	20,000	20,000	20,000	12,000	3,000
Well No. 4	25,000	25,000	25,000	25,000	15,000	4,000
Total Bbls.	70,000	68,000	66,000	60,000	40,000	10,000

Gross Revenue						
@ \$.20/bbl.	\$14,000	\$13,600	\$13,200	\$12,000	\$ 8,000	\$ 2,000

Annual Operating Expenses	4,000	4,000	4,000	4,000	3,500	2,000
Net Revenue	10,000	9,600	9,200	8,000	4,500	-0-

Midyear deferment factor	.960	.890	.825	.764	.707	
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Present Value	\$9,600	\$8,544	\$7,590	\$6,112	\$3,181	-0-
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TOTAL PRESENT
VALUE (1977-82) = \$35,027,000

Thus the indicated economic value of the pipeline property, based on the two techniques, is between \$35,027,000 and \$37,763,000. The assessment would probably be \$36,000,000 or slightly above.

D. OIL AND GAS RESERVES AD VALOREM TAX

General description. The newest member of the State's tax system is the Oil and Gas Reserves Ad Valorem Tax ("reserves tax"). In 1975 the Legislature passed this two-year tax which applies to oil and gas properties throughout the state having proven reserves. 26/

In 1975 the State found its General Fund balance dwindling while completion of the Trans-Alaska Pipeline was still two years away. Without an infusion of substantial revenues in 1976 and 1977, the State would have been in serious financial trouble. The reserves tax was devised as a method of obtaining needed revenues for the State during Fiscal Years 1976 and 1977. Its passage ensures the financial well-being of the State until North Slope oil begins to flow later this year.

Although the reserves tax is an ad valorem tax, it differs from the State's other property tax in at least two major aspects. First, the reserves tax is a revenue raising measure exclusively for the State, whereas the property tax also provides for certain municipal taxation. Second, the reserves tax is imposed on the value of the oil and gas in place (any right or interest to produce oil or gas), whereas the property tax is imposed on the hardware properties used in association with the exploration, production and pipeline

transportation of the oil.

The reserves tax is imposed on the value of a right to produce or recover oil or gas. This includes any interest in an oil or gas property or lease, be it a working interest, royalty interest, overriding royalty interest, production payment or net profit interest.

Properties subject to this tax include leasehold interests both on the North Slope and in the Cook Inlet area. Not all properties having proven reserves are subject to tax, for the statute provides exemptions to help assure that the tax would not unduly affect non-producing areas. For example, properties are exempt for five years, commencing on the date of the first completion, suspension or abandonment of the discovery well. Thus, after discovering oil in a particular field, the property is exempt for a period of time during which the owner could develop it without incurring reserves tax payments.

In addition, properties are exempt from taxation until the owner or operator of the property receives all necessary permits to construct a transportation facility or actually commences construction of a transportation facility for transporting the oil or gas from the taxable property. For example, North Slope gas and certain gas fields in the Cook Inlet areas have not been included as taxable properties

since there are as yet no pipelines that have received the necessary permits for transporting the gas to market.

Thus only those properties that have been discovered for at least five years and which have a viable way to get the oil and gas to market are taxable under the statute.

Assessment of taxable properties. Taxable properties are assessed on the basis of market value. Because properties with proven reserves are not often bought and sold, their market value is determined by using a capitalized income approach like that presented above for the assessment of a pipeline property. The net income from the property is first projected for the life of the reserves, using estimates of volumes of oil and gas in the ground which will be recovered, production rates, prices, and expenses. The annual net incomes are then discounted, using a discount factor, to arrive at their present values. The total of these discounted net incomes during the life of the reserves becomes the value of those reserves.

As in the preceding section, an example illustrates the valuation method best. For purposes of illustrating this method, a hypothetical example is used, patterned after the Sadlerochit formation of the Prudhoe Bay field. The figures used in this calculation were formulated during the legislative deliberations over the reserves tax in 1975 and were

developed without input from any of the taxpayers. They do not represent assumptions actually made, nor information actually used, in the 1976 reserves tax assessment for the oil reserves of that reservoir. They also are not actual assumptions or information used to date in preparing the 1977 assessment of those reserves. It does, however, illustrate the valuation method generally used in making reserves tax assessments.

Example

The estimated Market Value of oil and gas reserves in the Sadlerochit Formation as of January 1, 1976 is:

\$11,516,000,000
Eleven Billion Five Hundred Sixteen Million Dollars

Tax revenue that can be assessed to this value at a 20 mill rate is:

\$230,320,000
Two Hundred Thirty Million Three Hundred Twenty Thousand Dollars

The foregoing conclusions represent the most probable values considering the following limitations:

1. Pertinent data necessary for determining production rates for this area are insufficient at this date. Consequently, many sources of information have been used to finally project the most probable indication of future development and production rates.
2. Federal legislation could change the projected price of hydrocarbons.
3. Adequate transportation facilities must be provided for disposing of hydrocarbons at a favorable market place.

The market value extension in the table is preceded by an explanation of calculations and assumptions.

Gross Production (Column 1)

Oil production is projected to start through the Alyeska Pipeline in 1978 at a daily rate of 1,200,000 barrels per day. The rate is increased to a maximum of 1,800,000 barrels per day in 1981, remains constant for five years, then starts declining in 1986 at approximately 5% per year. The decline rate will increase gradually until the gas cap is in full production in 1997, then decline rapidly to depletion in 2006.

Gas associated with oil production will be produced four years before a gas line is available for sales. Produced gas will be used for fuel (approximately 37 billion cubic feet per year) and the remainder will be injected into the reservoir. In 1982 gas sales should start at approximately 400 billion cubic feet per year and increase to 760 billion cubic feet per year by 1985. This rate of production is projected to remain constant until blowdown (production of all gas including gas cap) is started in 1997. At that time a maximum production rate of 1100 billion cubic feet per year is projected for seven years, then declining at approximately 15% per year until depletion.

Net Interest Production (Column 2)

The purpose of this market value projection is to predict future revenue from taxable property. Therefore the 1/8 royalty interest owned by the State of Alaska is omitted, leaving a net interest of 7/8 (.875) of the gross production to be considered. The difference in net gas production and 7/8 (.875) of the gross is either injected volumes of gas or gas used for fuel.

Net Interest Income (Column 3)

Net production times a wellhead price is projected annually. Crude oil wellhead price of \$4.93 per barrel is projected for 1978 and escalated to \$7.75 per barrel by 1980. This represents a projected refinery price per barrel of \$10.00+, less transportation cost (including pipeline tariff). The net price of gas is projected at 50¢ per 1000 cubic feet.

Expense (Column 4)

Capital expenditures of \$702 million are projected for 1976 and 1977. These costs include drilling additional wells, site preparation and production, and injection facilities necessary for delivering crude oil to the pipeline at a daily rate of 1,200,000 barrels per day by 1978. Capital expenses continue through 1981 for additional wells and sites.

Production expense starts in 1978 and is projected at \$200,000 per well per year. The total production expense is increased to \$61 million per year in 1981. Gas injection expense is projected at 15¢ per 1000 cubic feet and is at the highest annual level the first four (4) years. In 1982 a volume of approximately 200 million cubic feet per year should represent an average rate of injection until 1994. Severance and property tax are projected annually and added to the capital, production, and injection costs to complete the total expenses incurred.

Net Income (Column 5)

The net interest income (Column 3) less expense (Column 4) is the net operating income for each year.

Discount Factor (Column 6)

A discount factor is the incremental rate of return that can be expected over a given period of time. An 18% annual, mid-year payment, discount factor is used in this valuation. Refer to the first year discount factor (.920575):

- 1) An investment of 92.0575¢ would yield \$1.00 in one (1) year.
- 2) An investment of 78.0148¢ would yield \$1.00 in two (2) years.
- 3) Etc.

Present Worth (Column 7)

The net increase (Column 5) for each year has been discounted by the corresponding year discount factor (Column 6) to yield a present worth by year. The total of all annual present worth values is the present worth (or market value) of this property as of January 1, 1976. 27/

Market Valuation - Sadlerochit Formation
As of January 1, 1976

Year	(1) Gross Production Oil Gas 1,000,000 B BCF		(2) Net Int. Production Oil Gas 1,000,000 B BCF		(3) Net Int. Income \$1,000,000	(4) Total Expense \$1,000,000	(5) Net Income \$1,000,000	(6) Discount Factor	(7) Present Worth \$1,000,000
1976						436	-436	.920575	-447
1977						230	-230	.780148	-179
1978	314	236	275		1355	341	1014	.661142	670
1979	438	328	383		2434	420	2014	.560292	1128
1980	584	438	511		3618	606	3012	.474822	1430
1981	657	657	575		4455	677	3778	.402392	1520
1982	657	657	575	376	4643	646	3997	.341010	1363
1983	657	821	575	525	4718	655	4063	.288991	1174
1984	657	821	575	525	4718	655	4063	.244908	995
1985	657	986	575	665	4788	664	4124	.207549	856
1986	624	986	546	665	4564	637	3927	.175889	691
1987	593	986	519	665	4354	611	3743	.149059	558
1988	534	986	467	665	3954	561	3393	.126321	429
1989	480	986	420	665	3588	513	3075	.107052	329
1990	432	986	378	665	3263	478	2785	.090722	253
1991	388	986	340	665	2964	441	2523	.076883	194
1992	330	986	289	665	2571	378	2193	.065155	143
1993	281	986	246	665	2239	336	1903	.055216	105
1994	239	937	209	700	1971	287	1684	.046793	79
1995	203	937	178	700	1727	243	1484	.039655	59
1996	173	937	151	700	1523	208	1315	.033606	44
1997	138	1100	121	963	1418	185	1233	.028480	35
1998	110	1100	96	963	1228	162	1066	.024135	26
1999	83	1100	73	963	1027	137	890	.020454	18
2000	62	1100	54	963	889	116	773	.017334	13
2001	43	1100	38	963	777	101	676	.014689	10
2002	30	1100	26	963	684	89	595	.012449	7
2003	21	1100	18	963	622	69	553	.010550	6
2004	15	935	13	818	509	57	452	.008941	4
2005	10	795	9	695	427	50	377	.007577	3
	9410	25073	8235	17765					11516

Market Value 1/1/76 = \$11,516,000,000

Under 15 AAC 05.920(b), the assessed property tax value of any production facilities on the land in the preceding example would be subtracted from the market value of the reserves, so as to avoid taxing those facilities twice.

The tax assessment of oil and gas reserves in Alaska, like the assessments of other kinds of properties that are very rarely bought or sold, represents an estimate of the price the property would be sold for, if it were sold freely in an open market under all conditions requisite to a fair sale. The absence of comparable sales data necessarily makes the estimate somewhat imprecise even though the best available engineering and economic judgments are applied in arriving at that estimated market value.

As was stated earlier, the reserves tax was enacted to generate badly needed revenues to the State prior to the commencement of operation of the Trans-Alaska Pipeline. Accordingly, the tax was given a temporary life of two years and will be imposed during 1976 and 1977 only. Then it expires.

Credits. For producing oil and gas properties the production tax payments during the 12 months preceding the payment date for their reserves tax payment may be credited against that reserves tax payment. 28/ This ensures that taxpayers will only pay the equivalent of one tax, either

the reserves tax or the production tax, whichever is higher.

For example, assume that a taxpayer had paid \$2,000,000 for production tax between June 30 of one year and June 30 of the next for an oil and gas lease in the Cook Inlet area. If the reserves tax liability for that lease is \$3,000,000 in 1976, the taxpayer would receive a \$2,000,000 credit and would only pay \$1,000,000 in reserves tax on June 30, 1976. The total tax bill for this taxpayer in this example is \$3,000,000 for both taxes.

In addition to the current offsetting credit, the statute also provides that any net reserves tax paid by the taxpayer gives rise to a credit against future production tax payments. This additional credit is called the "early development incentive credit" or EDIC. 29/ For properties paying reserves taxes, the statute provides that the taxpayer may build up a "bank" of allowable EDIC which may be applied against production tax payments in the future. As the EDIC is applied against the production tax liabilities, the credit "bank" will be reduced until it is exhausted. The EDIC applicable against any future production taxes cannot exceed 50 percent of the production tax liability for any one month's production. For example, owners of properties on the North Slope who pay reserves taxes in 1976 and 1977 will build up accrued EDIC equal to their reserves tax actually paid, and they may apply that EDIC against production tax payments once production

begins on the North Slope. At a 50 percent rate, it is estimated that it will take approximately five years for the taxpayers to exhaust their accrued EDIC.

The cumulative effect of the two-year life and the two credit features makes the reserves tax, in effect, a prepayment of production tax.

E. CORPORATE INCOME TAX

In addition to specific direct taxes on oil and gas production and properties, the oil and gas industry is subject to the corporate income tax on income earned within the state. Essentially, taxable income is defined to include taxable income under the Internal Revenue Codes with a few minor exceptions. These exceptions include such items as the disallowance of income tax deductions, foreign tax credits, a limit on investment credits and the elimination of the domestic international sales corporation exemption.

After the adjustments to federal taxable income are made, the resultant income is subject to tax at the State income tax rate. Under AS 43.20.021 corporations are taxed on the entire taxable income derived from sources in the state at a normal tax rate of 5.4 percent and a surtax rate equal to four percent. Since there is a surtax exemption of \$50,000 of taxable income, the first \$50,000 in taxable income is taxed at 5.4 percent and taxable income over \$50,000 is taxed at the rate of 9.4 per cent.

If a corporation is doing business only within the state or has income only from sources within the state, the corporation is taxable on its entire taxable income.

If, however, a corporation has income from business

activity which is taxable by Alaska and some other state or has income from other sources, both inside and outside the State, it must allocate and apportion its entire taxable income as provided in the Uniform Division of Income for Tax Purposes Act (UDITPA). This uniform method is set out in Article IV in the Multistate Tax Compact. 30/

Basically UDITPA provides for the allocation of non-business income, apportionment of business income and the use of other methods assigning income in exceptional circumstances.

Allocation of non-business income. Rents and royalties from real or tangible personal property, capital gains, interest, dividends or royalties from patents or copyrights are specifically allocated to a state under special rules if the income is non-business income. This method of specific assignment of certain categories of intangible income is called allocation and does not use a formula. It must be remembered, however, that these specific categories of income are only allocated if they constitute non-business income. If the income (rents, royalties, capital gains, interest, dividends) is business income, it must be apportioned by formula. Generally business income is defined to mean income arising from transactions in the regular course of the taxpayer's trade or business. Only income which arises totally outside the taxpayer's regular business operations is non-

business income and therefore specifically allocated.

Generally these specific types of income are allocated on the basis of the location of the property producing the income or to the taxpayer's commercial domicile. Rents and royalties from real property are allocated to the state where the property is located. Rents and royalties from tangible personal property are allocated to the state where the property is utilized unless it is not taxable in that state, in which case it is allocated to the taxpayer's state of commercial domicile. Capital gains from sales of real property are allocated to the state where the property is located. Capital gains from sales of tangible personal property are allocated to the state where the property was located at the time of the sale. If, however, the taxpayer was not taxable in the state where the property was located, the capital gain will be allocated to the state of commercial domicile. Interest, dividends and capital gains from sales of intangible personal property, are all allocated to the state of commercial domicile. Patent and copyright royalties are allocated to the state where the patent or copyright is utilized or, if the taxpayer is not taxable in that state, it is allocated to the taxpayer's commercial domicile.

Apportionment of Business Income. All business income, however, is apportioned to a state by use of a uniform formula. This uniform formula consists of three factors:

property, payroll and sales. First the property, payroll and sales in Alaska each become the numerator of three fractions, while property, payroll and sales everywhere become the denominator of the fractions. The three fractions are then averaged and business income is apportioned to the state by multiplying the taxable income by that average. Algebraically, the apportionment formula is:

$$\frac{\text{Alaska property}}{\text{Total property}} + \frac{\text{Alaska payroll}}{\text{Total payroll}} + \frac{\text{Alaska sales}}{\text{Total sales}} \div 3$$

An illustration of how the formula is applied can best be described by an example.

Example

Assume that ABC Oil Company has \$1,000,000 in property in Alaska, \$50,000 in payroll and \$25,000 in sales. The total property of the company everywhere is \$10,000,000; total payroll is \$250,000; and total sales are \$500,000. The company's apportionment formula would be:

$$\frac{1,000,000}{10,000,000} + \frac{50,000}{250,000} + \frac{25,000}{500,000} \div 3 = 7/60 \text{ or } .1167$$

If the company's taxable income was \$500,000, its Alaska tax liability would be: .1167 X \$500,000 = \$58,350 in Alaska taxable income. The Alaska tax would be calculated as follows:

5.4%	X	50,000	=	\$2,700
9.4%	X	8,350	=	785
Alaska tax due			=	\$3,485

To further explain the effect of apportionment, it is helpful to examine each factor in the apportionment formula.

As stated before, the property factor is a fraction whose numerator is the average value of the taxpayer's real and tangible personal property owned or rented and used in the state during the year. The denominator of the fraction is the average value of all the taxpayer's real and tangible personal property owned or rented and used during the year. In determining the values that go into this fraction, the following valuation principles are observed:

Property owned by the taxpayer is valued at its original cost. Rented property is valued at eight times the net annual rental rate. The net annual rental rate is the annual rental rate paid by the taxpayer less any annual rental rate received by the taxpayer from subrentals. The average value of property is determined by averaging the values at the beginning and ending of the year although the state may require averaging on a more frequent basis such as the monthly values during the year. For example, buildings and real estate owned by an oil corporation are included in the property factor at their original cost rather than at their market value. Equipment which is rented by a company would be included at 8 times its net annual rental rate. Other special leasehold properties such as oil and gas leases would be included in the property factor based upon the lease acquisition cost (bonus) plus 8 times the annual rental payments.

The payroll factor is a fraction, the numerator of which is the total amount of compensation paid its employees in this state during the year by the taxpayer. The denominator of the payroll factor is the total compensation paid its employees everywhere during the year. Compensation is treated as being paid in Alaska if the individual's service is performed entirely within the state. If an employee's service is performed both inside and outside the state but the service performed outside is incidental to the individual's service within the state, then the compensation will still be treated as paid in the state. If only some of an employee's service is performed in the state, then the compensation is treated as being paid in Alaska if the base of operations is in the state or the service is being directed in the state.

The sales factor is a fraction, the numerator of which is the total sales of the taxpayer in Alaska during the year. The denominator of the fraction is the total sales of the taxpayer everywhere during the tax period. Sales of tangible personal property are assigned to the state if:

- (1) the property is delivered or shipped to a purchaser, other than the United States Government, within Alaska regardless of the f.o.b. point or condition of the sale, or
- (2) the property is shipped from an office, store, warehouse, factory or other place of storage in Alaska and the purchaser is the United States Government or the taxpayer is not taxable in the state of the purchaser.

Sales, other than sales of tangible personal property, are assigned to the state if:

- (1) the income-producing activity is performed in Alaska; or
- (2) the greater portion of the income producing activity is performed in Alaska.

For example, these rules assign sales of petroleum products made by an oil corporation to Alaska only if they are destined to purchasers in Alaska. Sales of services, on the other hand, would be assigned to the state where the income producing activity is performed.

A special rule applies with respect to sales of tangible personal properties which are destined for a state when the taxpayer is not subject to tax by that state. In that case, the sales are "thrown back" to the state of origin. For example, if a corporation is making sales which are destined to a purchaser in Alaska, the sale would normally be assigned to Alaska. If, however, the only activity of the corporation in Alaska is the solicitation of orders and shipment of the product into the state from outside, then Alaska would not have jurisdiction to tax and the sale would be "thrown back" or assigned to the state of origin.

After the tax base is determined and the apportionment formula is calculated, it is then necessary to determine which portion of the tax base is subject to apportionment. The amount of income subject to apportionment is the net income from the unitary business, and the accounting method used to determine the net income from the unitary business is called the combined report.

The unitary business and the combined report. For many reasons, a business is not always run through one corporate entity. Especially in the case of very large companies operating on a global basis, literally hundreds of corporations may be formed to carry on the activities of what, in reality, is one unified, controlled business. To limit the determination of the Alaska source income to the one

corporate entity actually doing business in this state would be ignoring the reality that the one corporation is just an artificially defined part of the total business. Thus the net income from the entire unitary business is combined to determine the amount of income subject to apportionment to Alaska.

Although there are various tests to determine what is the unitary business, it is generally assumed that a business is unitary if there is (1) unity of ownership (more than 50% common ownership), (2) unity of operation (as evidenced by central purchasing, advertising, accounting and management divisions), and (3) unity of use (in its centralized executive force and general system of operation).

After the unitary business operations are defined, regardless of the structure or location of them, the results of operations of that total business are defined by reference to the Internal Revenue Code with specific Alaska modifications. That income is then divided between business and non-business income.

The business income of the entire business enterprise is then apportioned to Alaska using the three factor formula explained above. Any non-business income allocated to Alaska is added to the results of the formula and the Alaska tax rate is applied to the total assigned net income.

The effect of this unitary method of accounting (combination) is to apply the same formula approach for determining Alaska source income, regardless whether the business structures its operations through one corporation or through several.

To illustrate the concepts discussed above, an example of the division of income is discussed below.

Example

ABC Oil Co. is a worldwide oil company involved in the production, transportation and marketing of petroleum products. The business activities are carried out by the parent company and 54 subsidiaries. The operations in Alaska are carried out by three corporations:

1. The parent company involved in oil production,
2. A subsidiary navigation company involved in transportation of the crude oil to refineries, and
3. An Alaska marketing subsidiary which sells through service stations, products which were refined outside of Alaska. The three companies elect to file consolidated returns for Alaska purposes.

Its tax would be calculated as follows:

Income

Total "everywhere" business net income of Company A and all 54 subsidiaries	\$24,750,000
Add back unallowable income taxes	<u>20,250,000</u>
Alaska adjusted apportionable business income	\$45,000,000
Alaska allocated non-business income	\$10,000

Apportionment Factors

	Alaska	Worldwide	Alaska Factor
Property	245,000,000	6,140,000,000	4.0%
Payroll	5,000,000	356,000,000	1.4%
Sales	4,290,000	3,860,000,000	<u>.1%</u>

Of the total sales of all the companies, only .1% are destined to Alaska with 4% of the property in the state and 1.4% of the payroll located in Alaska.

Sum of the Alaska factors	<u>5.5%</u>
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Total apportionment factor percentage (5.5% divided by 3)	<u>1.8%</u>
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The consolidated Alaska taxable income and tax liability of the three companies operating in the state is computed as follows:

Total Alaska adjusted apportionable income of all companies	\$45,000,000
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Apportionment factor (divided by 3)	<u>1.8%</u>
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Alaska taxable income from apportionment of business income (1.8% X 45,000,000) =	\$ 810,000
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Alaska taxable income from allocation of non-business income	<u>\$ 10,000</u>
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Total Alaska taxable income	\$ 820,000
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Tax on first \$50,000 (@ 5.4%)	\$ 2,700
Tax on remainder (@ 9.4%)	72,380
Total Alaska tax due	\$ 75,080

Other methods of dividing income. In addition to the allocation and apportionment provisions discussed above, UDITPA provides other methods for extraordinary situations.

Section 18 of UDITPA provides:

If the allocation and apportionment provisions of this Article do not fairly represent the extent of the taxpayer's business activities in this state, the taxpayer may petition for or the tax administrator may require, in respect to all or any part of the taxpayer's business activity, if reasonable:

- (a) separate accounting;
- (b) the exclusion of any or more of the factors;
- (c) the inclusion of one or more additional factors which will fairly represent the taxpayer's business activity in the state; or
- (d) the employment of any other method to effectuate an equitable allocation and apportionment of the taxpayer's income. 31/

Thus the UDITPA provisions do allow some flexibility for the State or the taxpayer if the uniform allocation and apportionment provisions do not fairly represent the extent of the taxpayer's business activity in Alaska. These other methods include separate accounting, the use of different sets of factors or any other reasonable method.

One of those situations where the standard allocation and apportionment provisions do not accurately represent the taxpayer's business activities is the income taxation of transportation companies. Traditionally, transportation companies allocated and apportioned their income differently because of their unique characteristics which distinguish them from general mercantile businesses. Utilities and

financial institutions are specifically excluded from the provisions of UDITPA because of their unique characteristics, and the State must apply different allocation and apportionment provisions to them. 32/

For transportation companies, the State has applied different apportionment formulas to reflect their unique characteristics of continuous movement of property, employees and products through several jurisdictions. These formulas are also designed to prevent the assignment of income to high seas, foreign jurisdictions or the air ways. For example, the legislature has provided special allocation and apportionment rules for water transportation carriers transporting passengers or freight. For property located in fixed locations and wages of employees assigned to fixed locations, the standard apportionment formula in UDITPA applies. However, for the vessels used and wages of employees working on water transportation carriers, a "days spent in port" formula is used. Sales made by water transportation carriers are also assigned among the various states on the basis of a "days spent in port" formula. 33/

The "days spent in port" formula is a fraction whose numerator is the number of days spent by the water transportation carriers in Alaskan ports and whose denominator is the total number of days spent in ports everywhere by them. Days spent in ports do not include periods when the ships

are detained in port because of strikes, repairs, or seasonal reductions in service. Thus, under the "days spent in port" formula, property and payroll is assigned on the basis of days spent in port, which gives recognition to the loading and unloading of passengers and freight while at the same time not attributing income to the high seas.

In addition to transportation companies, there may be other industries which warrant special formulas based upon unique characteristics.

Separate accounting. Besides modification in the apportionment formula and the adoption of new and different apportionment formulas, UDITPA also provides for the use of separate accounting. It should, however, be noted that, as with the modifications of the factors, it is used only in exceptional cases rather than being the rule.

Separate accounting assumes that the portion of the business operated in one state can be separated from the rest of business operated elsewhere and accounted for separately. In effect, the corporation's activities in one state are treated as if they were carried on by a separate and distinct corporate entity. Essentially, the separate accounting method involves the specific identification of items of income and expense that represent the taxpayer's operations in the one state, and constructing a taxable income from

those identified items of income and expense without reference to the rest of the business.

The State has not sanctioned the use of separate accounting, however, except in situations where there is no unitary business, where the business in Alaska is truly separate from the business carried on elsewhere, and where it would not result in a distortion of income. There are a number of perceived problems associated with this approach which are discussed in Chapter VII.

Chapter II - Footnotes

- 1/ Sec. 2, ch. 7, ESLA 1955; approved April 9, 1955.
- 2/ Sec. 1, Ch. 31 FSSLA 1967; effective October 11, 1967.
- 3/ Sec. 1, ch. 110, SLA 1968; effective July 17, 1968.
- 4/ The Disaster Severance Tax was repealed by sec. 2, and the gas production tax increased by sec. 1, of ch. 247, SLA 1970; both effective July 1, 1970.
- 5/ Sec. 1, ch. 247, SLA 1970; effective July 1, 1970.
- 6/ The rates beginning July 1, 1980 would have been 43.2 cents a barrel for the first 300, 48.2 cents for the next 800, 50.7 cents for the next 1500 and 55.7 cents for production over 2500 barrels a day. Sec. 4, ch. 101, SLA 1972.
- 7/ AS 43.55.015(b) as enacted by sec. 4, ch. 101, SLA 1972.
- 8/ AS 43.55.010(e) as enacted by sec. 3, ch. 101, SLA 1972; AS 43.55.015(d) as enacted by sec. 4, ch. 101, SLA 1972.
- 9/ Under the reduced cents-per-barrel rates that would have become effective July 1, 1980, the "floor" on production tax and royalty revenues would have corresponded to price of \$2.50.
- 10/ Amerada Hess, et. el. v. State (Sup'r Crt. No 72-2719); ARCO Pipe Line Co. v. Herbert (Sup'r Crt. No 72-2798); Mobil Pipe Line Co. v. State (Sup'r Crt. No. 72-2720). These cases were consolidated into a single proceeding.
- 11/ Ch. 4, FSSLA 1973.
- 12/ AS 43.55.015(b) as amended by sec. 2, ch. 4, FSSLA 1973. Oil above 40° is taxed as if its gravity were 40°.
- 13/ AS 43.55.015(c) as amended by sec. 2, ch. 4, FSSLA 1973; 15 AAC 05.694.
- 14/ Sec. 1, ch. 5, FSSLA 1973, codified as AS 43.57.
- 15/ Sec. 1, ch. 1, FSSLA 1973, codified as AS 43.56.
- 16/ AS 29.53.045 and .050(b) as enacted by secs. 3 and 4, respectively, ch. 1, FSSLA 1973; AS 29.53.055 as amended by sec. 5, ch. 1, FSSLA 1973; effective January 1, 1974.

- 17/ If the assessed value of taxable oil and gas properties would result in a total assessed valuation exceeding this product (225 percent of average per capita statewide assessed value, multiplied by the number of the municipality's residents) when added to the assessed valuation of other property in the municipality, then the Department of Revenue designates what portion of the oil and gas assessment the municipality may tax. AS 43.56.010(c).
- 18/ AS 29.53.045(d).
- 19/ AS 43.56.030.
- 20/ AS 43.56.010(d).
- 21/ 15 AAC 05.840.
- 22/ AS 43.56.060(c).
- 23/ AS 43.56.060(d).
- 24/ AS 43.56.060(e)(1).
- 25/ AS 43.56.060(e)(2).
- 26/ Sec. 1, ch. 159, SLA 1975; effective June 26, 1975.
- 27/ Prepared February 10, 1975 by Malcolm Jarrell of Pritchard & Abbott, Valuation Engineers (Fort Worth, Texas) for the Department of Revenue.
- 28/ AS 43.58.030; 15 AAC 05.975.
- 29/ AS 43.58.180; AS 43.55.018; 15 AAC 05.980; 15 AAC 05.985; 15 AAC 05.695.
- 30/ AS 43.19.010, Art. IV.
- 31/ AS 43.19.010, Art. IV.
- 32/ AS 43.19.010, Art. IV.
- 33/ AS 43.20.071.

CHAPTER III. HISTORY OF REVENUES AND EXPENDITURES

A. INTRODUCTION

Before judging the adequacy of the State's tax system and the State's long term revenue needs, it is useful to step back and examine the expectations of State officials shortly after the 1969 North Slope lease sale regarding projected oil development. It is then interesting to compare those expectations with what actually happened in both the private sector and the government sector or with what is now projected to happen in the years to come.

One expression of the State's revenue expectations concerning oil development was articulated in Comments on the Proposed Trans-Alaska Pipeline (July 1971) in response to a request by the U.S. Department of Interior for information on the Trans-Alaska Pipeline. At one point the State commented:

From the State's point of view the things that can be accomplished with the North Slope oil revenues are the principal justification for building the Trans-Alaska Pipeline. The money will mean a better life for those people living in America's Arctic and Sub-Arctic regions. 1/

Thus, in mid-1971 the State expected the development of Prudhoe Bay to produce sufficient additional revenue to allow for the upgrading of the living conditions of the State's population through increased governmental services.

The oil and gas revenue projections made in the State's comments at that time included both the State's one-eighth royalty payments and its sliding scale production tax (three to eight percent at that time). These projections were based upon estimated crude oil prices on the West Coast, tanker tariffs, pipeline tariffs and through-put rates at that time. For example, West Coast refinery prices were estimated to range between \$3.22 and \$3.02 a barrel with \$3.12 as the most probable. The 1971 oil and gas revenue projections with accompanying assumptions are shown on the next table. 2/

1971 Oil and Gas Revenue Projections
(Selected Years)

YEAR	WELLHEAD OIL PRICE (\$/BBL)	WELLHEAD GAS PRICE (\$/MCF)	DAILY PRODUCTION (in millions)		REVENUE (in millions)		
			OIL(BBL)	GAS(MCF)	ROYALTY	TAX	TOTAL
76	1.98	.15	1.15	1.03	104	49	153
77	2.22	.15	1.70	1.53	172	86	258
78	2.23	.15	1.70	1.53	173	87	260
79	2.28	.15	1.85	1.60	192	93	285
80	2.32	.15	2.00	1.68	216	101	317
81	2.34	.15	2.00	1.68	216	101	317
82	2.35	.15	2.00	1.80	217	101	318
83	2.36	.15	2.00	1.85	218	102	320
84	2.37	.15	2.00	1.83	220	102	322
85	2.38	.15	2.00	1.88	221	101	322

In addition to the oil and gas revenue projections, overall revenue and expenditure projections through 1981 were made at that time as follows. 3/

GENERAL FUND RECEIPTS AND EXPENDITURES
(1971 projections in thousands)

YEAR	NON INVESTMENT REVENUE	INVESTMENT REVENUE	TOTAL REVENUE	TOTAL EXPENSES	SURPLUS OR DEFICIT	GENERAL FUND END OF YEAR
1971	143,356	74,238	217,594	296,000	(79,005)	830,989
1972	152,598	55,355	207,953	301,100	(93,146)	737,840
1973	172,252	47,754	220,006	343,495	(123,487)	614,350
1974	175,033	37,825	212,858	393,249	(180,390)	433,956
1975	187,518	33,978	221,496	450,071	(228,573)	205,379
1976	354,216	10,938	365,154	514,806	(149,651)	55,727
1977	476,242	(44)	476,198	589,157	(112,958)	(57,231)
1978	491,406	(9,189)	482,215	674,105	(191,889)	(249,121)
1979	528,670	(22,920)	505,749	771,540	(265,790)	(514,912)
1980	577,207	(41,313)	535,893	883,191	(347,297)	(862,311)
1981	593,995	(66,231)	527,763	1,011,059	(483,295)	(1,345,506)

These projections show that even with projected oil revenues the State would begin with budget deficits in 1971 and have a negative general fund balance beginning in 1977. By 1981 there was projected a budget deficit of \$483.3 million dollars and the general fund balance would be in the red by \$1.3 billion dollars.

In May 1972 the State updated its comments about the pipeline and showed an even more dismal picture of its finances. 4/ A downward revision in the State's revenue projections was made because of projected increases in pipeline costs and delays. Income from royalties and production taxes were not expected for the first two years of production, and wellhead values were projected not to exceed 43 cents until the eleventh year of production. As a result, total North Slope oil revenues were estimated to reach \$36.9 million dollars in 1977, 36.8 million dollars in 1978, \$118.6 million dollars in 1979, 125.8 million dollars in 1980 and 119.9 million dollars in 1981. Only by 1988 were oil revenues forecasted to reach the levels anticipated in the 1971 projections. 5/

In response to this outlook, the State's revenue need in 1972 was explained:

While Alaska's expenditures as an underdeveloped state continue to grow to meet the needs of the people, delay and cost escalation on a Trans-Alaska route have combined to shrink the absolute amount of revenue anticipated and to reduce the proportional contribution of that revenue to the State's budget especially in the early years of production. 6/

Since 1972 the oil pricing picture has been radically altered through the actions of OPEC (Organization of Petroleum Exporting Countries). While federal price controls have so far prevented Alaska from becoming a beneficiary of those

price increases for its Cook Inlet production, the changes have done much to restore the financial outlook for the State in the future.

B. DEVELOPMENTS IN THE PRIVATE SECTOR

Before proceeding to the actual development of revenues and expenditures of the State from 1969 to the present, it is useful to stop and look at developments in the private sector of the State's economy during this same time. Thus it is important to note the effect that recent oil development has had on the people of the State.

One effect of oil development activities in the private sector is indicated by changes in both the nominal and real incomes of residents in the State as shown in the State Income Series developed by the U.S. Department of Commerce and published in the Survey of Current Business. 7/

As shown in the table on page III-12, these state income series indicate that the income effect of the pipeline activities was not necessarily spread equally over the various population groups in the State. For example, wages and salaries earned by civilians in the state increased by 263.5 percent between 1969 and 1975, while proprietors' income (income of self employed businessmen with an unincorporated business) generated in the State increased by only 83.3 percent during the same period. At the same time, income (in the form of dividends, interest and rent) received by property owners living in the State increased by 232.9 percent from 1969 to 1975. The State's recipients of transfer pay-

ments (such as social security and other pensions and annuities) experienced income increases of 351.7 percent in the same period.

It appears that the non-military wage and salary earning populace benefited the most from the pipeline activities, while the proprietors shared only to a limited extent in the economic development. Their income gains amounted to about 31 percent (or less than one third) of the income gains realized by wage and salary earners. However, if some of these proprietors also owned rental property in the State, they shared in the over 232 percent income increase in the property income category. Probably only some proprietors in the State shared equally in the benefits which accrued to the property owners. Thus most benefits of the pipeline activities accrued to wage earners, many of whom were not residents of the State.

Although total wages and salaries increased substantially in the State, the income series shown in the table on page III-12 also indicate substantial amounts of income flowing out of the State. For example, in 1975, the income received by persons not residing in the State amounted to \$604 million, or 16.5 percent of the total labor and proprietors' income generated in the State. For 1969 through 1973, this share fluctuated between 4.4 to 5.2 percent, and increased to 9.6 percent in 1974. 8/

To determine the actual effect of the oil development in the private sector, however, it is necessary to look beyond the total income gains and look at the real increases in income adjusted by the cost of living effects in the State during this same period (1969-1975). The costs of living (inflation) rose substantially in Alaska during this period especially in 1974 and 1975, and the actual percentage increases are shown in the following table.

Cost of Living Increases
(percent)

1970	3.49
1971	3.01
1972	2.66
1973	4.23
1974	10.84
1975	13.74

To determine the real gains of the income group shown in the income series during 1969 through 1975, the total income figures must be deflated for the inflationary effects. Deflating the income series on the table on page III-12 shows that the extraordinary inflationary pressures of the last few years restricted the real economic gains of the various groups and limited the effective improvement in the income position of some of the groups to only about a third of the apparent income gains.

As stated earlier, proprietors participated the least in the economic gains as expressed in nominal terms. This was also the case in real terms as well. In 1974 and 1975 (the years of major improvements in their income) their real income was restricted the most because these two years had the highest inflationary pressures. It appears that this may have been due to the time lag which develops before the benefits of economic improvements are spread over the whole system, while inflationary pressures can become effective sooner.

Recipients of transfer payments were affected in a similar way. While they experienced a substantial improvement in their income position in current dollars (335% from 1970-1972), inflation tended to curtail these improvements. For example, as shown in the table on page III-12 this group actually received a reduction in real income during 1974 and 1975. This may be explained by the fact that changes in this group's income may have been determined less by the economic activities within the State than other external factors. Though this income group shared in both the negative impact of the development activities and the economic benefits, these persons were probably sheltered from both influences to such an extent that they still realized the greatest increase in real income of all groups from 1969 to 1975.

Generally, it appears from the table on page III-12 that wage and salary earners within the State were impacted less by the inflationary developments than any other group. Property owners were also in a good position, but proprietors shared in the positive developments only after a time lag.

When we analyze the development in the personal income series for persons actually residing in the State, the results should be qualified to some extent. It appears that civilian wage and salary earners as a group may have done well only because some of them were able to avoid the inflationary development within the State. Thus the seasonal labor force was probably able to take most advantage of the economic development by limiting their spending within the State, and that in turn probably curtailed the benefits to the business sector.

INCOME SERIES 1/
(millions of dollars)

A. INCOME SERIES IN CURRENT DOLLARS

	<u>1969</u> ^{2/}	<u>1970</u> ^{3/}	<u>1971</u> ^{4/}	<u>1972</u> ^{4/}	<u>1973</u> ^{5/}	<u>1974</u> ^{5/}	<u>1975</u> ^{5/}
BY PLACE OF WORK:							
TOTAL LABOR: PROPRIETORS INCOME	1,166	1,291	1,491	1,620	1,755	2,349	3,656
WAGE AND SALARIES	1,065	1,179	1,359	1,477	1,596	2,147	3,408
LESS: FEDERAL, MILITARY	199	221	229	242	246	254	261
CIVILIAN WAGES & SALARIES	866	958	1,130	1,235	1,350	1,893	3,147
PROPRIETORS INCOME	68	74	84	85	95	117	125
SS CONTRIBUTIONS	44	48	63	69	94	139	223
LESS: RESIDENCE ADJUSTMENT	-57	-67	-69	-72	-80	-226	-604
NET LABOR & PROPRIETORS INCOME BY PLACE	1,122	1,243	1,358	1,478	1,581	1,984	2,829
PLUS: PROPERTY INCOME	70	82	89	98	139	186	233
PLUS: TRANSFER PAYMENTS	58	79	102	121	262	232	262
PERSONAL INCOME BY PLACE OF RESIDENCE	1,250	1,404	1,549	1,697	1,982	2,402	3,324

B. INCOME SERIES IN REAL TERMS

TOTAL LABOR; PROPRIETORS INCOME	1,101	1,178	1,321	1,398	1,453	1,754	2,401
WAGE AND SALARIES	1,006	1,076	1,204	1,274	1,321	1,603	2,238
CIVILIAN WAGES & SALARIES	818	874	1,001	1,066	1,118	1,414	2,066
PROPRIETORS INCOME	64	68	74	73	79	87	82
NET LABOR & PROPRIETORS INCOME BY PLACE	1,059	1,134	1,203	1,275	1,309	1,482	1,856
PLUS: PROPERTY INCOME	66	75	79	85	115	138	153
PLUS: TRANSFER PAYMENTS	55	72	90	104	216	173	172
PERSONAL INCOME BY PLACE OF RESIDENCE	1,180	1,281	1,372	1,464	1,641	1,794	2,183

1/ U.S. Department of Commerce-Survey of Current Business, Washington, D.C.; See following notes.

2/ August 1972

3/ August 1973

4/ August 1974

5/ August 1976

C. DEVELOPMENTS IN THE PUBLIC SECTOR

As explained in Chapter IV, the revenue and expenditure patterns from 1966 to the present were examined to make projections of future expenditures and revenues.

1. Expenditures

When comparing the actual budget expenditures with earlier expectations, actual expenditures in the most recent years compare more closely to the 1971 estimates than the later expectations. This comparison is shown in the following table:

<u>Year</u>	<u>1971 Expenditure Projections</u>	<u>Actual Expenditures</u>
1971	296.6	259.9
1972	301.1	284.3
1973	343.5	309.1
1974	393.2	435.3
1975	450.1	455.7

Thus, for example, General Fund expenses for fiscal year 1975 were estimated at \$450.1 million dollars and the actual expenditures were \$455.7 million dollars.

In addition to looking at only the nominal changes in expenditures from 1971 through 1975, it is also relevant to examine the real increases in the budget during this

same period by eliminating inflationary influences. Accordingly, the expenditures have been deflated and are shown in 1967 dollars in the following table. In addition the percentage change in real expenditures are shown in the table.

YEAR	ACTUAL EXPENDITURES	REAL EXPENDITURES (1967 DOLLARS)	PERCENTAGE CHANGE IN REAL TERMS
1969	131.6	124.6	
1970	163.6	149.3	19.8
1971	259.9	230.0	54.0
1972	284.3	245.3	6.7
1973	309.1	256.7	4.6
1974	435.3	324.9	26.6
1975	455.7	296.3	(8.8)

The largest increases of the budget in real terms were from 1970 to 1971 and from 1973 to 1974 of 54 percent and 26.6 percent respectively. The smallest increases were from 1971 to 1972 and from 1972 to 1973. In addition there was actually a decrease of budget expenditure real terms from 1974 to 1975.

It is important to note that the increases in budget outlays in real terms do not necessarily depict an overall improvement in all service levels. The increases were mainly concentrated in 3 budget categories: education, health and social services, and transportation. ^{9/}

2. Revenues

The State's revenues increased from 1971 through 1975 more than had been projected in 1971. For example, in the State's 1971 projections, revenues in 1975 were expected to be \$221.5 million dollars whereas the actual revenues were \$333.4 million dollars. The differences between the 1971 revenue projections and actual revenues from 1971 through 1975 are shown in the following table.

<u>Year</u>	<u>1971 Revenue Projections</u>	<u>Actual Revenues</u>
1971	217.6	220.4
1972	208.0	219.2
1973	220.1	208.2
1974	212.8	255.0
1975	221.5	333.4

The substantial differences between the early projections and the actual revenue collections probably reflects the underestimation of the general impact which pipeline construction had on the State's economy.

It should be noted, however, that even with the increased revenue collections, there were budget deficits beginning in 1971 but these deficits were not as large as were earlier contemplated.

Chapter III - Footnotes

- 1/ State of Alaska, Department of Law - Comments on the Proposed Trans-Alaska Pipeline, July 30, 1971, p. 158.
- 2/ Ibid., p. 172.
- 3/ Ibid., p. 178.
- 4/ State of Alaska, Department of Law - Comments on the Trans-Alaska Pipeline and Its Alternatives, May 1972.
- 5/ Ibid., pp. 30-32.
- 6/ Ibid., p. 32.
- 7/ U.S. Department of Commerce, Social and Economic Statistics Administration, Bureau of Economic Analysis - State and Regional Personal Income, 1971, Survey of Current Business, August 1972; State and Regional Personal Income, 1959-1972, Survey of Current Business, August 1973; State and Regional Personal Income, 1958-1973, Survey of Current Business, August 1974; State Personal Income, 1974-1975, Survey of Current Business, August 1976.
- 8/ Ibid.
- 9/ State of Alaska - Budget Documents, Fiscal Years 1973 through 1976, Executive Budget Fiscal 1977.

CHAPTER IV. REVENUE AND EXPENDITURE PROJECTIONS

A. EXPENDITURE PROJECTIONS

1. Projection of regular budget items. Instead of simply using the State's total budget figures for past years as the basis from which expenditure trends may be identified and future budgets projected, each year's budget since 1966 was analyzed in terms of the present eight program categories: Education, Health and Social Services, Administration of Justice, Natural Resources and Environmental Conservation, Public Protection, Development, Transportation and General Government. Because the budget format was changed in 1972, earlier budgets first had to be reassembled into the current format in order to obtain a series of comparable expenditures long enough for meaningful analysis of each category.

The effects of the prevailing inflation during the historic base period tend to distort the results of any attempt to regress expenditures against independent socio-economic variables (such as population) during the same period. This distortion is amplified by the fact that the inflation rate was not uniform, but varied from year to year. To eliminate this undesirable effect from the analysis, the money spent each year for each program category was deflated to 1967 dollars. In other words, the annual expenditures were expressed, for analysis purposes, in terms of dollars having the same buying power as the dollar had during 1967. The deflation was done on the basis of the Consumer Price

Index reported for Anchorage.

The deflated expenditures for each of the eight program categories were then compared with independent variables to see if there appeared to be any sort of relationship between those variables and any of the program category's expenditures. The techniques employed to establish whether there was any relation is one commonly used in statistics, called regression analysis.

The results of this analysis show a high degree of correlation between population growth and expenditure growth for seven of the eight program categories, indicating that population changes were the major explanatory factor for the changes in expenditures in those programs. 1/ For Health and Social Services and for Development, the changes seem most closely associated with changes in the non-military resident population. The other five program categories seem to be influenced primarily by the total resident population. The one category whose expenditures appear unrelated to population change is General Government. Its budget changes are perhaps best explained in terms of the need for an adjustment in the overall State budget due to the State's revenue situation.

The projection for future General Government expenditures was made directly in current-dollar terms, using the historic

time trend observed for its past expenditures. The forecasts for the seven other program categories were made by estimating the resident population year by year during the forecast period, determining from these estimates the expenditures for each category in deflated 1967 dollars on the basis of historic relationship to the population, and then inflating the 1967 dollars on the basis of actual inflation to date and projected inflation for the future. 2/

Until Fiscal Year 1973 the annual resident population increases were close to three percent, never exceeding three and a half percent from one year to the next. However this changed with the beginning of pipeline construction in 1974, and annual increases exceeded even 10 percent. This sudden change in resident population growth clearly indicates developments different from the influences that historically prevailed. It is not assumed that these higher rates will continue. Instead, after an overall decline upon the completion of TAPS, the resident population will again reflect the underlying factors that induced the historic growth rate, and by Fiscal Year 1979 it will again be on the rise.

This rise would probably follow the historic annual growth pattern if there were no new influx of people for additional construction projects of vast magnitude. However, there will be at least one such project, the pipeline for Prudhoe Bay gas.

The prospect of the gas pipeline has two effects on the resident population. First, it will encourage some new residents brought up by TAPS to remain in anticipation of the new economic activity and opportunities the gas pipeline will bring. A similar anticipatory effect occurred with TAPS during the time when its construction was delayed: people who were already in Alaska waited out the delay. In the case of the gas pipeline this effect will keep the resident population at a higher plateau than would otherwise be the case, and it is assumed they will be absorbed into the state's socio-economic fabric without significantly altering it, as their counterparts were absorbed during the TAPS delay. 3/ The second population effect of the gas pipeline is the new residents it will attract when its construction begins.

To project the resident population during the forecast period, it was necessary to proceed in two steps. First, a baseline was projected from the present resident population. It reflects the emigration of some of the TAPS-induced population increase but also reflects the "anticipation effect" (those who will remain for the gas pipeline). The baseline was assumed to be subject to the underlying factors that caused the historic population growth and accordingly is projected to increase at the historic rate.

The second step is the projection on the population influx when the gas pipeline construction begins. To make

this projection, direct construction data submitted by the three proponents in their application filings before the Federal Power Commission were used but adjusted by one year to reflect the delay in the beginning of construction. Based on these respective employment data, estimates were made for the direct construction-induced total employment, population and income impacts by using an updated version of the econometric model generated by the University of Alaska Institute of Social, Economic and Governmental Research for the "Man in the Arctic" program. These estimates, when incorporated with the historic population growth, produce the following projections:

State Resident Population Forecasts
for the Three Gas Pipeline Projects
(thousands of people)

<u>Fiscal Year</u>	<u>El Paso</u>	<u>Arctic Gas</u>	<u>Alcan</u>
1976	415.0	415.0	415.0
1977	420.0	420.0	420.0
1978	403.5	402.3	420.7
1979	418.9	405.1	411.0
1980	442.6	414.2	428.7
1981	456.1	425.0	442.9
1982	456.1	434.0	448.8
1983	460.8	445.2	454.6
1984	471.1	457.1	465.4
1985	485.1	472.0	479.8

Using these three resident population forecasts, the total operating budgets for the eight program categories were projected on the basis of their observed relationships

to the resident population. Then the General Fund portion of those budgets was calculated in accordance with the State's present accounting practices. The resulting General Fund expenditures are tabulated below for each of the three proposed gas pipeline projects. 5/

Forecast of Ordinary General Fund Expenditures
For the Three Gas Pipeline Projects
FY 76 - FY 85
(\$ millions)

	<u>El Paso</u>	<u>Arctic Gas</u>	<u>Alcan</u>
FY 76	616.4	616.4	616.4
FY 77	728.0	728.0	728.0
FY 78	802.7	802.7	802.7
FY 79	899.1	869.8	881.8
FY 80	945.2	882.1	915.1
FY 81	1011.8	923.7	972.2
FY 82	1057.8	971.3	1024.0
FY 83	1104.6	1028.2	1073.8
FY 84	1150.7	1086.9	1126.4
FY 85	1212.2	1159.2	1191.4

It is essential to remember that this table does not reflect any offsetting revenue benefits that may be offered by a pipeline project, and consequently it is no indication of the relative net benefits to the State of any of the three proposals. It would be totally misleading, for example, to contend that the Arctic Gas route is superior to the other two solely on the basis of the lower level of State expenditures indicated for it by this table.

2. Extraordinary budget expenditures. Quite apart from the effects of the construction of a pipeline for Prudhoe Bay gas, the State will experience variations in budget expenditures due to legal requirements or to decisions made by the State. The causes for these variations would include royalty payments into the Alaska Native Fund until the State has paid a total of \$500,000,000, the costs for the Capital Move and the costs connected with opening the Haul Road.

2-A. Alaska Native Fund. Under the terms of the Alaska Native Claims Settlement Act, all lands selected by the State but which had not yet been patented to it were made subject to a two percent oil and gas royalty interest payable out of the State's one-eighth royalty interest. This royalty provision applies to the Prudhoe Bay field. Thus, until the \$500,000,000 has been paid, amounts equal to 16 percent of the State's royalty proceeds will have to be budgeted for Native Fund payments.

The amount of these payments will depend on the price of the oil in the field. Later in this chapter the Department's projections for that price, assuming the free market sets the price, are presented and explained. However, it could be that market forces are prevented from operating freely and fully, with a resulting diminution of the price. This possibility is explored in Chapter V.

For present purposes, the Native Fund payments are presented on the basis of the free-market price, but it should be remembered that these expenditures would change if the possibilities discussed in Chapter V were to come to pass.

Projected Native Fund Payments ^{6/}
(based on projected free-market prices)
(\$ millions)

FY 77	0.1
FY 78	39.5
FY 79	72.3
FY 80	97.4
FY 81	118.9
FY 82	139.7
FY 83	29.9
FY 84	-0-
FY 85	-0-

2-B. Capital Move. The costs to be borne by the State in moving the capital from Juneau to the Willow site are uncertain. The Capital Site Selection Committee estimated a cumulative cost through 1990 of \$2,642,665,000 for the Willow site, with a tentative allocation of \$520.82 million as costs that the State would pay. ^{7/} The Committee noted:

In the category of public/private facilities, the difference between the state portion at current allocations and total estimated 1990 costs is \$724,630,000. These costs could be borne by a combination of private Municipal, Federal and State entities. ^{8/}

The Boeing study analyzed relocation costs to the Anchorage/Palmer, Talkeetna and Fairbanks/Nenana areas

them to costs of keeping the capital in Juneau.

In presenting its conclusions, the Boeing study reported the following total incremental costs for the State in terms of present-value dollars discounted to 1980: 9/

<u>Relocation Site</u>	<u>Additional Cost (millions of 1980 present-value dollars)</u>
Anchorage/Palmer	109.7 to 113.7
Talkeetna	245.1 to 250.5
Fairbanks/Nenana	315.4 to 319.6

The Department of Revenue has not attempted to develop its own estimate of the relocation costs to the State. That is far outside the scope of this report and is beyond the area of the Department's experience and expertise.

To provide the reader with some indication of the State expenditures that may be associated with the Capital Move, the Department has prepared four hypothetical cases based on arbitrarily chosen figures for the total relocation cost borne by the State. These figures are \$500 million, \$1 billion and \$2 billion. The choice of these figures does not indicate any opinion regarding what the total costs to the State will be: you, the reader, must form your own opinion as to that. Rather, they are intended to allow you to see the approximate annual expenditures that could correspond to whatever portion the reader assumes will be

paid by the State of the total \$2.6 billion relocation cost estimated for the Willow site by the Capital Site Selection Committee.

For purposes of these examples, it was assumed that the financing will be by General Obligation Bonds, rather than funding the move from current revenues. This assumption spreads the costs out through time, making the annual expenditures much smaller than if current revenues are spent. 10/

The particular assumptions hypothesized for the bond financing are: the relocation costs borne by the State will be paid by bonds issued in roughly equal amounts in 1979, 1982, and 1985. 11/ The bonds run 22 years, with payments on the principal to be made for 20 years. Interest is seven percent. The State will make two payments per fiscal year.

The table below shows the resultant annual expenditures under these assumptions for the four hypothetical cases. The expenditure data are expressed in millions of dollars.

	Case A (\$500,000,000)	Case B (\$1,000,000,000)	Case C (\$1,500,000,000)	Case D (\$2,000,000,000)
FY 79	6.0	11.9	17.5	23.6
FY 80	11.9	23.8	35.0	47.3
FY 81	20.4	40.8	60.0	81.0
FY 82	26.2	63.1	75.8	101.9
FY 83	30.8	61.9	91.5	122.8
FY 84	38.4	77.4	114.8	153.7
FY 85	42.8	86.4	128.8	172.1

It bears repeating that your own judgment about relocation costs paid by the State is the factor that must determine which of these four cases you give weight to in estimating the State's annual expenditures for the move.

2-C. Haul Road. The North Slope Haul Road and the question of opening it to public use have been the subjects of considerable public discussion. Based in large part on the legalities entailed in the federal funding for the Haul Road, Governor Hammond has announced that the road will be opened. ^{12/} However, as an interim measure, the Governor has also declared that the opening of the road will initially be limited to industrial and mining users "until the peak industrial demands for the road have subsided" and until there develops "a rational plan for the sound and profitable management of State and Federal lands in the area affected by the road." ^{13/} Those users will bear the costs incurred by the State to keep the road open on a limited basis for their use.

For purposes of projecting expenditures for the Haul Road, the user fees were assumed to offset the State's costs during the period of limited use. Based on the necessary capital improvements projected by the Department of Highways and Public Safety, for the Governor's study of the Haul Road issue, on their projected operating costs, on an annual inflation rate of five percent and on a 5.2 percent interest

rate on the financing for the capital improvements, the following expenditures are indicated (figures are in millions of dollars):

pre-FY 81	-0-
FY 81	5.5
FY 82	21.6
FY 83	22.7
FY 84	24.4
FY 85	25.7

B. PROJECTIONS OF PETROLEUM-RELATED REVENUES

The State's petroleum-related revenues fall into either of two types: those which are directly based on production volumes and prices (production tax 14/ and royalty revenues), and those which reflect those factors only indirectly (property tax revenues).

1. Projected production volumes and prices. It is common sense that a purchaser, faced with a choice between two suppliers of similar goods, will prefer buying from the supplier who offers his goods at a lower price. This basic notion applies to the market place, too: if a seller seeks to enter the market, he will have difficulty doing so if the price he asks is greater than the price of the other sellers of similar goods.

This limitation on the price that a seller can sell his goods at has been incorporated into the Department's method in projecting the price for Prudhoe Bay oil. This oil will go primarily to United States refinery markets (except for those amounts that may be physically moved to Japan in exchange for other oil delivered to the Atlantic or Gulf of Mexico coasts). Even with Prudhoe Bay oil, there will not be enough American-produced oil to meet American refinery demand. In other words, Prudhoe Bay oil does not have to meet the price of U.S. domestic crude

oil to find a buyer since the buyers need more oil than there is available domestically. This gap between domestic supply and domestic demand has been, and will continue to be, bridged by increasingly larger amounts of foreign supplies. It is therefore imported oil that competes with North Slope oil and will tend to limit its market value.

Perhaps ironically, the country exporting crude oil most similar in quality to Prudhoe Bay oil is also the largest exporter - Saudi Arabia. While the Saudi Arabian "Light," "Medium" and "Heavy" crudes are all quite similar to Prudhoe oil in terms of straight-run refined product yields and in terms of refining costs, the closest overall match seems to be the Saudi "Medium." Accordingly, the Department's projection of North Slope oil prices has been based on a forecast of refiner's costs to acquire this Arabian oil and have it delivered to the refinery; from that total delivered cost, the transportation costs for Prudhoe Bay oil (from the field to the refinery) are netted out to arrive at a value in the field.

This market distribution analysis is made more complicated by an anticipated surplus of crude oil on the West Coast. While there will be an ever greater shortage of crude oil nationwide, the expected production from existing fields, Prudhoe Bay, Elk Hills, and from the California and Alaska Outer Continental Shelf will exceed the physical

capacity of the refineries on the West Coast. To be sold any surplus crude oil will be transported to other areas of the United States where the oil shortage will continue or will be shipped to Japan where it will be exchanged for foreign oil to be delivered to the oil-short areas of the U.S. The latter option has special complications. Because the federal statute authorizing the construction of TAPS forbids the export (except to Canada or Mexico) of oil shipped through TAPS without a determination by the President and Congress that this is in the national interest, and because no such decision has been made, the Department of Revenue has assumed for projection purposes that the surplus oil will be transported, initially by tanker and later by pipeline, from the West Coast to other regions of the country east of the Rocky Mountains.

The existence of multiple refinery markets for Prudhoe Bay oil (some on the West Coast and others elsewhere) complicates the forecast of its value in the field.

It has been assumed that when the West Coast surplus develops, some or all of the surplus oil will move to the Gulf of Mexico region. The value in the field for this surplus will also tend to be the value for oil absorbed on the West Coast. 15/

The following table with its notes sets out in detail the assumptions underlying the Department's forecast of Prudhoe Bay oil prices for each fiscal year through 1985. Pricing for Fiscal Years 1978 and 1979 is set out on a quarterly basis (the quarter is indicated by the Roman numeral in parentheses after the year) along with the average price for the year.

PROJECTED PRUDHOE BAY WELLHEAD VALUE
(IN CURRENT DOLLARS PER BARREL)

YEAR (QTR)	ARABIAN 31° F.O.B. RAS TANURA	PG/US TANKER TARIFF	REFINERY PRICE	AK/US TANKER TARIFF	LOWER 48 TARIFF	TAPS TARIFF	TOTAL TARIFF	PRUDHOE BAY WELLHEAD VALUE
1977	11.56 (a)	1.65 (b)	13.21	.57 (c)	--	--	--	--
1978 (I)	11.84	1.72	13.56	.58	--	5.92 (d)	6.50	7.06
1978 (II)	11.84	1.72	13.56	.58	--	5.92	6.50	7.06
1978 (III)	12.68	1.90 (e)	14.58	.60	1.10 (f)	5.15	6.85	7.73
1978 (IV)	12.68	1.90	14.58	.60	1.10	5.15	6.85	7.73
1978	12.26	1.81	14.07	.59	.55	5.54	6.68	7.39
1979 (I)	12.68	1.98	14.66	.62	.80 (g)	5.15	6.57	8.09
1979 (II)	12.68	1.98	14.66	.62	.80	5.15	6.57	8.09
1979 (III)	13.30	1.98	15.28	.64	.80	5.09	6.53	8.75
1979 (IV)	13.30	1.98	15.28	.64	.80	5.09	6.53	8.75
1979	12.99	1.98	14.97	.63	.80	5.12	6.55	8.42
1980	13.77	2.06	15.83	.66	1.20 (h)	4.79	7.65	9.18
1981	14.60	2.14	16.74	.68	1.30	4.38	6.36	10.38
1982	15.47	2.23	17.70	.71	1.40	4.15	6.26	11.44
1983	16.40	2.32	18.72	.74	.80 (i)	3.88	5.42	13.30
1984	17.38	2.41	19.79	.77	.80	3.64	5.21	14.58
1985	19.43	2.51	20.94	.80	.81	3.45	5.06	15.88

NOTES: PROJECTED PRUDHOE BAY WELLHEAD VALUE (table on preceding page)

(a) As explained in the text preceding the table, the cost to a refiner to obtain imported replacement oil of comparable quality to Prudhoe Bay crude represents the extent to which the open market would justify the price of Prudhoe Bay oil. Saudi Arabian "Medium" crude (31° API gravity, 2.5% sulfur) serves as the benchmark from which Prudhoe Bay prices are derived. The \$11.56 price represents the average price for Saudi Arabian "Medium" F.O.B. at Ras Tanura on the Persian Gulf. This average price reflects the December 1976 pricing action by Saudi Arabia. In the projection the price is assumed to rise at six percent per annum to offset U.S. and European inflation; in terms of dollars with constant value (constant buying power), the Arabian price is unchanging. In light of a developing global shortage of energy sources, particularly oil and gas, this assumption may be conservative, especially after 1985. On the other hand, assuming that the real (constant-value dollar) price increases at 3% a year yields a nominal-dollar price of \$91.45 (\$23.50 in real terms, as of January 1977) by the year 2000, and at that price oil as an energy source may have been significantly supplanted.

(b) Tanker transportation tariffs for the Persian Gulf to U.S. West Coast route during Fiscal Year 1976 were approximately \$1.59 per barrel when computed on an average annual AFRA basis. While the current world tanker market could continue to suppress tanker tariffs in the future, tariff rates are projected to cover annual increases in variable costs. Tanker tariffs consequently are increased in this projection at an annual rate of four percent. The \$0.21 per barrel import excise tax has been considered in arriving at these transportation costs.

(c) Tanker tariffs for the route between Valdez and the U.S. West Coast are computed on a weighted average basis according to port of destination and throughput volume. As in the case of foreign flag tankers, tariffs are increased 4% per annum from the composite base rate computed for operations in Fiscal Year 1978.

(d) The TAPS tariff each year will generate enough revenue to cover expenses, depreciation of the capital investment and a profit. A major determinant of the tariff is the number of barrels transported during the year. The more barrels, the lower the tariff can be in order to produce the necessary annual income.

Annual average throughput for TAPS is projected as follows (in millions of barrels per day): FY 78 - 0.94; FY 79 - 1.3; FY 80 - 1.53; FY 81 - 1.6; FY 82 - 1.7; FY 83 - 1.78; FY 84 - 1.88; FY 85 - 1.9. These rates reflect production in addition to that of the main Prudhoe Bay reservoir. TAPS tariffs are calculated on the basis of the pipeline's operating year, which is assumed to be the calendar year. The low average throughput expected during the 1977 operating year (i.e., the first two quarters of FY 78) is the reason for the high initial tariff. Some have predicted that the initial tariff will be a "break even" tariff, and on that basis it could be as low as \$4.13. A tariff based on the average throughput during the first year of operation (which will correspond to the State's fiscal year but which would end in the middle of the pipeline's second operating year) would be about \$4.85. The tariff projection is made on the basis of the entire pipeline, not on the basis of the financial situation of the eight individual companies that own it. Capital costs for the 1.2 million-barrel-a-day capacity are estimated at \$9.45 billion, including capitalized interest. Expansion of TAPS capacity to 2 million barrels a day is assumed to cost an additional \$995 million. All tariff projections assume that interest on debt financing for the pipeline will be recognized as an allowable expense in setting the tariff.

(e) Beginning in early 1978 (calendar year), the expected West Coast crude oil surplus is expected to develop. The surplus oil is assumed to go to the Gulf of Mexico area. Accordingly, the tanker tariffs are those for the trade between the Persian Gulf and the Gulf of Mexico. The tariffs are projected from the average AFRA basis during Fiscal Year 1976 and escalated at four percent per annum. Again, the 21 cent excise tax on imports is recognized.

(f) The "Lower 48 Tariff" here is the extra tankering costs assumed for moving the oil via the Panama Canal to the Gulf of Mexico. It is assumed that this is done on a temporary basis while one or more pipelines are built eastward across the Rocky Mountains from the West Coast.

(g) This is the projected tariff for a pipeline of 500,000 barrels a day capacity. The SOHIO pipeline has been used as the basis for the projection. Total cost for this capacity are estimated at \$500 million.

(h) It is assumed that the West Coast surplus continues to develop beyond the initial pipeline capacity (500,000 barrels per day) to move it eastward. While additional capacity is coming on line (expansion of the first pipeline or construction of a second line), tankers are again employed to transport oil to the Gulf of Mexico area.

(i) At this point additional pipeline capacity becomes available to transport the entire surplus out of the West Coast area.

Using these projected prices and the production assumptions given in note (d) to the preceding table, the following production tax and royalty revenues are forecast.

Projected Production Tax
and Royalty Revenues of the State 16/
FY 76 - FY 85
(\$ millions)

	<u>Production Tax Revenue</u>	<u>Royalty Revenue</u>	<u>Total</u>
FY 76	27.9	43.9	71.8
FY 77	27.1	38.5	65.6
FY 78	103.3	329.0	432.3
FY 79	153.9	520.2	674.1
FY 80	192.6	661.0	853.6
FY 81	296.3	788.3	1084.6
FY 82	471.2	916.2	1387.4
FY 83	595.3	1173.5	1768.8
FY 84	677.7	1359.0	1768.8
FY 85	740.3	1497.1	2237.4

2. Projected property tax revenues. It is assumed that TAPS reaches its present target of 1.2 million barrels a day by the end of this calendar year at its announced cost of \$7.7 billion. Production facilities needed at Prudhoe Bay to supply that volume of oil are already on the Slope and will be completed before the pipeline. It is assumed that an expansion of TAPS capacity is authorized by its owners next year and that the additional pipeline and production facilities for that increased capacity will move into the state as early as practicable after that authorization. The

expansion is assumed to be completed within two years of its initiation.

Construction of the gas pipeline is assumed to begin during Fiscal Year 1979. About the same time work will begin to ready the field for producing the gas for sale.

Municipal ad valorem tax levies are assumed to follow their historic patterns.

Under these assumptions the following State property tax revenues have been projected, depending on the gas pipeline route chosen.

Projected State Property Tax Revenues
For All Oil & Gas Properties Statewide
(\$ millions)

	<u>El Paso</u>	<u>Arctic Gas</u>	<u>Alcan</u>
FY 76	83.3	83.3	83.3
FY 77	140.9	140.9	140.9
FY 78	168.3	168.3	168.3
FY 79	171.8	170.6	170.6
FY 80	174.6	171.6	193.2
FY 81	214.7	176.6	226.7
FY 82	268.3	185.4	251.8
FY 83	307.0	195.6	257.0
FY 84	352.0	204.9	261.4
FY 85	358.7	212.6	295.9

3. Projected additional corporate income tax revenues due to Prudhoe Bay production. As production from the Prudhoe

Bay field approaches, there will be an increase in corporate income taxes that would not be reflected in the historic trend for this tax. As explained in Chapter II, Alaska income tax payments by large multistate and multinational corporations are not only determined by their economic situation within Alaska, but also by their economic well-being within the rest of the United States and the world. These companies compute their Alaska taxable business income by means of the three-factor apportionment formula described in Chapter II, based on proportion of their total property, sales and payroll that is in Alaska. Because of the magnitude of the investments in Alaska (TAPS and the field facilities at Prudhoe Bay, for instance), the business income apportioned to Alaska will increase. These increases have been estimated as follows (in \$ millions): 17/

FY 78	46.0
FY 79	51.0
FY 80	54.0
FY 81	57.0
FY 82	60.0
FY 83	63.0
FY 84	66.0
FY 85	69.0

C. PROJECTION OF NON PETROLEUM-RELATED REVENUES

1. Projected collections from business-related tax sources. Collections from tax sources historically show more rapid fluctuations than were observed on the expenditure side. Consequently, more difficulties were encountered in developing projection methods. On the assumption that there is a general tendency for a multitude of changes to offset each other, some of the revenue sources were lumped together for projection purposes, in the hope that the general development so described will become more stable and easier to determine.

Based on this assumption, those major taxes were aggregated whose revenues have a tendency to respond to business fluctuations. These are the Individual Income Tax, Corporation Income Tax, Fiduciary Tax, and the Business License Tax. Collections from these taxes vary with the business climate prevailing in the state. The data for non-agricultural wages and salaries data were used as indicators of the business climate, based on the previous observations (in Chapter III) that wage and salary earners evidently participated most directly in the economic development in the state, and because these incomes determine the consumption patterns unfolding in the state's economy. Thus, while non-agricultural wages and salaries are not the actual basis for these taxes (though they are the most important part

of the Individual Income Tax base), they are an indication for the economic fluctuations observed in the State which determine the revenue collections from these sources. For projection purposes wage and salary data were used which were produced by the revised MAP-Model based on the different pipeline scenarios described in part A of this chapter.

Projected Collections from
Business-Related Tax Sources
(Individual and Corporate Income Taxes,
Fiduciary Tax and Business License Tax)
FY 76 - FY 86
(\$ millions)

	<u>El Paso</u>	<u>Arctic Gas</u>	<u>Alcan</u>
FY 76	196.5	196.5	196.5
FY 77	247.5	247.5	247.5
FY 78	118.3	118.3	118.3
FY 79	142.3	123.7	131.7
FY 80	173.4	138.3	156.6
FY 81	186.2	154.2	173.6
FY 82	177.8	164.0	175.5
FY 83	183.3	180.2	182.3
FY 84	201.7	199.3	200.7
FY 85	223.7	221.3	222.7

These figures do not reflect the increase in Corporate Income Tax collections due to Prudhoe Bay production, which were projected in the preceding section.

2. Projected collections from non business-related tax sources. While the business-related taxes are relatively closely tied to the general economic situation in the state, other tax collections are influenced more distinctly by the population development. This is especially true for the

excise taxes; that is, the General Fund portion of the Cigarette Tax, the Alcoholic Beverage Excise Tax, the Highway Fuel Tax, Aviation Fuel Tax, and the Marine Fuel Tax. Because of this, these excise taxes were projected by use of the alternative population data for the three gas pipelines, as described in part A of this chapter.

Projected Collections from Excise Taxes
FY 76 - FY 85
(\$ millions)

	<u>El Paso</u>	<u>Arctic Gas</u>	<u>Alcan</u>
FY 76	34.0	34.0	34.0
FY 77	32.1	32.1	32.1
FY 78	31.6	31.6	31.6
FY 79	33.2	31.2	32.0
FY 80	36.9	32.5	34.8
FY 81	38.8	34.2	36.9
FY 82	39.0	35.6	37.8
FY 83	39.6	37.3	38.7
FY 84	41.2	39.0	40.3
FY 85	52.3	41.3	42.5

In addition, the school tax was projected separately. This is a \$10 annual tax imposed on any person age 19 or over who is receiving income through civilian employment in the State. Based on the above-mentioned population data, the civilian non-agricultural wage and salary employment was estimated, and from this the school tax revenue was projected.

3. Total tax revenues. The sum of the individually projected tax revenues constitutes the bulk of the non petro-

leum-related tax revenues. Therefore, by use of these data and a projection equation determined on the basis of historic relationships, the total non petroleum-related tax revenue for the projection period was estimated.

Projected Total Non Petroleum-Related
Tax Revenues
FY 76 - FY 85
(\$ millions)

	<u>El Paso</u>	<u>Arctic Gas</u>	<u>Alcan</u>
FY 76	243.5	243.5	243.5
FY 77	309.0	309.0	309.0
FY 78	167.3	167.3	167.3
FY 79	195.3	172.6	182.4
FY 80	233.3	190.1	212.6
FY 81	249.6	209.3	233.6
FY 82	240.4	221.5	236.6
FY 83	247.2	241.2	245.0
FY 84	269.0	264.0	267.0
FY 85	295.4	290.6	293.5

4. Other revenues. Fees and fines contribute a significant portion of the revenues going into the State's General Fund. Often they are paid in form of a flat dollar amount for privileges or services enjoyed or actions taken. Because of this, the collections from these revenue sources are closely related to the total resident population observed in the State. Therefore, State collections from these revenue sources were projected on the basis of the population projections.

With respect to the remaining miscellaneous revenues, except for the interest income from investments, it was not

possible to determine any specific development pattern other than a simple time trend which showed some extraordinary variations when the State Ferry System disposed of one of its vessels. These State revenues were projected by extending the time trend over the forecast period.

The most decisive fluctuation in the historic collection data from ongoing revenue sources can be observed with respect to the interest income from investments. When the State received more than \$900 million dollars in bonus bids from the September 1969 oil and gas lease sale, the historic income patterns were suddenly altered. Historically, the interest income had developed in close relationship to the General Fund balance, which did not fluctuate excessively over time because the State's economic and financial situation was relatively stable. The receipt of this large amount did not alter the historic relationship between the two series. Rather it moved the development to a higher plateau. Due to the fact that the ordinarily prevailing budget constraints ceased to exist, the General Fund balance started to exhibit larger fluctuations, and the interest income did so correspondingly. For projection purposes the prospective General Fund balances therefore had to be estimated. The balances reported in the State's Annual Financial Report were not used. Instead, a balance was computed by adding to the last reported balance the total projected unrestricted General Fund revenues and deducting from the sum the projected General

Fund expenditures. However, with commencement of the oil production from Prudhoe Bay, the State's financial situation will change again in a way comparable to 1969, except that this change will continue on an ongoing basis for longer than the projection period. The people of the State made one decision concerning the anticipated change. They authorized the establishment of the Permanent Fund. For projection purposes it was assumed that the Fund will earn interest income at rates comparable to the General Fund balance, and that the interest so earned will be transferred to the General Fund. The projected interest income thus includes interest from both the Permanent and General Fund balances.

D. SUMMARY

The three tables that follow summarize the projected General Fund expenditures, the non petroleum-related income, the petroleum-related income and the balances of the General Fund and the Permanent Fund (based on 25%). Expenditures for the Haul Road or the Capital Move are not reflected, but Alaska Native Fund payments are.

General and Permanent Fund Finances with El Paso Pipeline FY 76 - FY 85 (\$ millions)

	<u>General Fund Expend.</u>	<u>Petro. Revenue</u>	<u>Non Petro. Revenue</u>	<u>Interest</u>	<u>Total Revenue</u>	<u>General Fund Balance</u>	<u>Perm. Fund Balance</u>
FY 76	616.4	378.2	292.6	31.7	702.5	569.3	-0-
FY 77	728.1	489.9	362.8	26.9	879.6	718.3	2.4
FY 78	853.8	646.6	225.8	35.0	907.4	689.7	84.7
FY 79	971.4	896.9	260.2	53.9	1211.0	799.2	214.7
FY 80	1042.6	1082.2	302.4	68.3	1452.9	1044.3	380.0
FY 81	1130.7	1356.3	322.0	92.9	1771.2	1487.7	577.0
FY 82	1197.4	1715.7	315.2	131.2	2162.1	2223.3	806.1
FY 83	1134.5	2136.8	324.5	189.0	2650.3	3445.7	1099.5
FY 84	1150.7	2454.7	349.4	279.8	3083.9	5039.2	1439.2
FY 85	1212.2	2665.1	379.3	395.6	3440.0	6892.7	1812.5

General and Permanent Fund
Finances with Arctic Gas Pipeline
FY 76 - FY 85
(\$ millions)

	<u>General Fund Expend.</u>	<u>Petro. Revenue</u>	<u>Non Petro. Revenue</u>	<u>Interest</u>	<u>Total Revenue</u>	<u>General Fund Balance</u>	<u>Perm. Fund Balance</u>
FY 76	616.4	378.2	292.6	31.7	702.5	569.3	-0-
FY 77	728.1	489.9	362.8	26.9	879.6	718.3	2.4
FY 78	853.8	646.6	225.8	35.0	907.4	689.7	84.7
FY 79	942.1	895.7	236.3	53.9	1185.8	803.3	214.7
FY 80	979.5	1079.2	256.8	68.5	1404.5	1063.0	380.0
FY 81	1042.7	1318.2	279.0	94.0	1691.2	1514.5	577.0
FY 82	1111.0	1632.8	294.3	132.8	2059.9	2234.4	806.1
FY 83	1058.0	2025.4	317.1	189.7	2532.2	3415.1	1099.5
FY 84	1086.9	2307.6	343.2	278.0	2928.8	4917.3	1439.2
FY 85	1159.2	2519.0	373.3	388.3	3280.6	6664.5	1813.5

General and Permanent Fund
Finances with Alcan Pipeline
FY 76 - FY 85
(\$ millions)

	<u>General Fund Expend.</u>	<u>Petro. Revenue</u>	<u>Non Petro. Revenue</u>	<u>Interest</u>	<u>Total Revenue</u>	<u>General Fund Balance</u>	<u>Perm. Fund Balance</u>
FY 76	616.4	378.2	292.6	31.7	702.5	569.3	-0-
FY 77	728.1	489.9	362.8	26.9	879.6	718.3	2.4
FY 78	853.8	646.6	225.8	35.0	907.4	689.7	84.7
FY 79	954.1	895.7	246.5	53.9	1196.1	801.6	214.7
FY 80	1012.5	1100.8	280.5	68.4	1449.7	1073.6	380.0
FY 81	1091.2	1368.3	305.0	94.6	1767.9	1553.3	577.0
FY 82	1163.7	1699.2	310.7	135.1	2145.0	2305.6	806.1
FY 83	1103.7	2086.8	321.8	193.9	2602.5	3511.1	1099.5
FY 84	1126.4	2364.1	347.0	283.7	2994.8	5039.7	1439.2
FY 85	1191.4	2602.3	376.9	395.6	3374.8	6848.8	1813.5

Chapter IV - Footnotes

- 1/ The historic population statistics published by the U.S. Department of Labor were used. These figures indicate the population as of the first of July of the respective year, which is at the endpoint and beginning successive State fiscal years. To obtain a figure more reflective of the population during the State's fiscal year, the published population figures at the beginning and end of a fiscal year were simply averaged. This technique is somewhat crude, but no better method presented itself.
- 2/ Expenditures in the Education program category mostly depend on the number of enrolled pupils and the assessed valuation recorded for the school districts, because these are the major determinants in the statutory formula for State aid for education. The number of pupils was found to vary with the total population. The assessed valuation also appears to be strongly influenced by variations in the number of people residing in the state. Because of the mechanics of the formula for computing State educational aid, there is a difference of two years between the fiscal year for which the State aid is computed and the fiscal year for which the assessed valuation is recorded. Consequently the expenditures for this program category are dependent upon current-year changes in the total resident population and upon population changes during the two prior years. The projections for Education are correspondingly more complex than indicated in the text, although the fundamental approach is similar.
- 3/ While we can depict a systematic relationship, we are unable to determine the specific factors influencing the actual population development. However, we do believe that the underlying factors will continue to exist and be effective in the same direction as they did historically.
- 4/ These figures differ from those in the Department's Revenue Journal, Vol. 1, No. 1 (July 1976) due to the time adjustment to reflect delay and because the updated econometric model results were considered more appropriate.
- 5/ These numbers are based on those computer print-outs by Department of Revenue for the El Paso, Arctic and Alcan scenarios in which the program does not reflect any effects for the Capital Move or the Haul Road. They are prepared by subtracting the "ANAT" figures (State portion of Native Fund payments) from the "GFEX" figures (General Fund expenditures) and reflect the General Fund portion

of the State's "ordinary" annual operating budget. The "extraordinary" items of the State's budget are those discussed individually in the text: Native Fund, Capital Move and Haul Road. The figures for FY 76 and FY 77 are based on the actual budgets for those years. FY 78 figures are based on the Governor's budget for that fiscal year. Figures for subsequent year are based on Department of Revenue projections.

- 6/ These numbers were based on assumed past payments of \$2.2 million made to the Fund. Actual payments apparently were \$6,361,742.28 as of October 31, 1976. The payment projected for FY 83 would accordingly be reduced by the difference between estimated and actual past payments.
- 7/ Capital Site Selection Committee, The State of Alaska Capital Site Selection Project: The Selection of Three Alternative Sites (summary), p. 36.
- 8/ Ibid.
- 9/ Boeing Computer Services, Inc., Alaska State Capital Relocation Study (July 31, 1974), p. 76 (Exhibit 45).
- 10/ Under this assumption the General Fund balance becomes much larger than if the actual relocation are paid by annual appropriations. This balance is a source of interest earnings, which are a significant part of the unrestricted revenues that are projected in the second part of this chapter.
- 11/ The exact amounts of the hypothetical issues are (in millions of dollars):

	<u>1979</u>	<u>1982</u>	<u>1985</u>	<u>TOTAL</u>
Case A	170	165	165	500
Case B	340	335	325	1000
Case C	500	500	500	1500
Case D	675	665	660	2000

- 12/ Thus, unless we are willing to risk paying millions and face endless litigation, the Haul Road will be opened. That conclusion, however, is not the total picture; it merely frames the basic issue: conditions under which the road is opened - for opened it will be. Commitments made in previous administrations, public pressures and the road's very presence will assure it.

Governor Jay S. Hammond, "The North Slope Haul Road," View from behind the Governor's Desk #13 (August 23, 1976).

- 13/ Governor Jay S. Hammond, "North Slope Haul Road Interior Policy Statement" (September 1976).
- 14/ The one-eighth of a cent per barrel conservation tax depends on production volumes but not price, as does the production tax when paid on the cents-per-barrel basis.
- 15/ The value at Prudhoe Bay netted back from the refiner's cost to replace it with Saudi crude is greater when the "net back" is from the West Coast than it is when the "net back" is from the Gulf of Mexico. This is because the cost for Saudi oil delivered to port on either coast is roughly the same, while there is a greater distance and correspondingly higher transportation cost to get oil from Prudhoe Bay to the refiner in the Gulf of Mexico area. Netting that greater transportation cost out of roughly the same refinery price leaves a lower value in the field for the surplus oil that must be shipped to the more distant refinery.
- Where several producers all have Prudhoe crude which they cannot absorb at their own refineries on the West Coast, they must either sell it to an unaffiliated West Coast refinery or ship it eastward at the extra cost. In other words, if the non-integrated producer sells its oil to a West Coast refiner on the basis of its "net back" price from the Gulf of Mexico (or wherever it would ship the oil if it couldn't sell the oil on the West Coast), then that producer will be in the same condition as if he had shipped the oil out of the West Coast area. Since the producer would have to pay those extra transportation costs if the oil is not sold on the West Coast, free competition to sell on the West Coast would lower the "net back" price in the field for oil sold on the West Coast. The price would fall to the same level as the "net back" price in the field for oil sold in the Gulf of Mexico region. Thus the "net back" price based on the surplus oil is what theoretically would determine the price in the field for Prudhoe Bay oil going to West Coast refiners.
- 16/ Payments to the Alaska Native Fund have not been deducted from the royalty income presented in the table. The production tax forecast reflects the application of a total of \$506.5 million worth of EDIC for actual and estimated reserves tax payments in FY 76 and FY 77, respectively; it also includes the conservation tax.
- 17/ These figures are based on estimates prepared by Barbara Sorensen for the Legislative Affairs Agency in June 1976.

CHAPTER V. PROBLEM AREAS IN THE PRESENT TAX SYSTEM

A. DEFICIENCIES IN THE CORPORATE INCOME TAX

Some members of the 1976 Alaska Legislature and a consulting economist for the oil industry who has been hired as a consultant by the Alaska Legislature have expressed concern about the effectiveness of the State's corporate income tax. 1/ The concerns expressed were that the present income tax structure does not return to the State of Alaska 9.4 percent of the net income actually earned in Alaska and that it does not put multistate or multinational corporations on a par with domestic corporations.

The Department of Revenue in conjunction with the Legislative Affairs Agency hired two consultants, Jerome M. Zeifman and Kenneth G. Ainsworth, both of whom had extensive experience with state income tax structures. Jerome M. Zeifman is currently an Associate Professor of Law at Santa Clara University School of Law, where he teaches state and local taxation. 2/ Kenneth G. Ainsworth is a Professor of Economics and is Chairperson of the Department of Economics at Allegheny College, Meadville, Pennsylvania. 3/

Both Zeifman and Ainsworth had worked for several years in the area of state income taxation of interstate business, which culminated in an exhaustive study for the Committee on the Judiciary of the U.S. House of Representatives. 4/ Zeifman and Ainsworth have concluded their study for the

Department of Revenue and the Alaska Legislature entitled "The Taxation of the Petroleum Industry Under Alaska's Corporate Income Tax." For our study we have relied substantially on the judgments and findings as well as the recommendations of Zeifman and Ainsworth.

As discussed in Chapter II, the State's corporate income tax base is largely defined pursuant to the Internal Revenue Code, although the total amount of tax base subject to allocation and apportionment to Alaska is the entire taxable income of the corporate unitary business that does business both within and without Alaska. The amount of taxable income, however, that is actually attributed to Alaska is that amount of income obtained by multiplying the entire taxable income of the unitary business by the three factor formula of property, payroll, and sales.

1. The tax base. The first deficiency cited by Zeifman and Ainsworth in their report, and one with which we agree, is the definition of the tax base. 5/ To a large extent, a corporation's taxable income is defined pursuant to federal law under the Internal Revenue Code. Although the use of federal taxable income as a tax base has some advantages (such as ease of compliance for the taxpayer and an established body of law), it also has serious drawbacks. One drawback results from the eroded tax base which it presents. The definition of federal taxable income incorporates several

tax incentives and subsidies which have been enacted by Congress over the years that are designed to provide economic stimulus to the national economy as well as to encourage or discourage certain types of social behavior. Each incentive or stimulus enacted, however, erodes the tax base. These erosions include such items as: accelerated depreciation, percentage depletion, intangible drilling costs, foreign tax credits, capital gains, net-operating loss carry forwards and investment credit - to name just a few.

U.S. Representative Vanik in a recent presentation of the Annual Corporate Tax Study to the U.S. House of Representatives made some pertinent remarks on the federal eroded tax base. 6/

Mr. Speaker, readers should remember that the corporate tax rate, unlike the progressively scaled individual tax rates, is a statutory 48 percent. It is an exception, as this study shows, if a giant company pays even 40 percent in effective Federal income taxes, let alone the 48 percent corporate rate.

But I must stress that these companies are apparently able to reduce their U.S. income taxes through entirely legal means. The companies have made the utmost advantage out of every one of the Tax Code's "stimulants" that seek to promote one beneficial end or another; they have used every tax "incentive" or deferral permitted under law.

While the Tax Code has unfortunately developed into a tax lawyer's paradise of exemptions, exceptions, special provisions and benefits, these features mostly apply to corporate taxpayers. While individual taxpayers and small businesses also have special tax measures that reduce their tax rates, the amount is practically insignificant compared to corporate business sector tax benefits.

Overall, the 148 companies whose data allowed tax rate computation paid an effective Federal income tax of 21.3 percent, down more than a full percentage point from tax year 1974's 22.6 percent average. These figures are not even half of the 48 percent statutory corporate tax rate.

By incorporating wholesale the federal corporation tax law, Alaska adopts a much eroded tax base each time that Congress passes a new tax shelter or tax incentive.

Zeifman and Ainsworth point out in their report a further recognition of the federal eroded tax base. 7/ They explain:

As has been pointed out in the recent "Report to the Senate and House Committee on the Budget" of the United States Congress, the encouragement or subsidy, as the case may be, takes the form of a reduced income tax liability. The amount of the reduction from the "normal" tax owed has come in recent years to be called a "tax expenditure." In theory at least, the Government could have collected the full tax and used some part of it in some other way - by a Federally administered grant or loan program, for example - to encourage the same activity or help the same industry. [footnote omitted]

...

The concept of tax expenditures has been incorporated in the Congressional Budget Act of 1974, which requires the listing of present and proposed tax expenditures and a calculation of their revenue loss implications. In particular, Section 202(f)(1) requires the Director of the Congressional Budget Office to report annually on the "levels of tax expenditures under existing law."

To illustrate the magnitude of the tax expenditures (tax subsidies), Zeifman and Ainsworth include specific

estimates of tax expenditures from the most recent report of the Director of the Congressional Budget Office. 8/

SELECTED FEDERAL TAX EXPENDITURE ESTIMATES FOR CORPORATIONS
(Millions of dollars, fiscal years)

Function	1977	1978	1979	1980	1981
Expensing of exploration and development costs	840	1,045	1,285	1,540	1,85
Expensing of research and development expenditures	695	725	755	785	81
Capital gains: (other than farming & timber)	900	1,015	1,090	1,170	1,2
Asset Depreciation Range (ADR)	1,630	1,825	2,000	2,095	2,1
Deferral of income of controlled foreign corporations	365	365	365	365	36
Deductibility of charitable contributions (social services)	352	402	446	489	53

Thus whether you call various items tax expenditures, incentives, subsidies or encouragements, there is widespread recognition of substantial erosion in the federal tax base which Alaska has incorporated.

The erosions in the federal tax base apply specifically to oil corporations as well as to corporations in general. In fact the erosions may be more dramatic than for other industries. As explained by Representative Vanik "Oil remains largely untaxed. Five multinational oil companies

paid \$107 million in corporate income taxes to the Federal Government on pretax profits of more than \$2.2 billion for an effective average tax rate of 4.8 percent." 9/

As part of Representative Vanik's Corporate Tax Study, a listing of approximate effective tax rates of 148 selected large corporations was made. We have extracted some of those corporations listed which are particularly pertinent to this study of the oil and gas tax structure and have included them in the following table.

As can be seen in this table of selected oil corporations, the approximate effective federal tax rates on the corporate net income (before federal tax) reported to shareholders ranged from 1.8 percent to 35.6 percent. Adoption of the same eroded tax base by Alaska, even assuming that all income is taxable by Alaska, would mean a comparable Alaska effective tax rate of .28 to 5 percent instead of the 9.4 percent statutory tax rate for these selected companies.

	Approximate adjusted net income before Federal and Foreign income tax (thousands)	Approximate adjusted net income before Federal income tax (thousands)	Approximate current Federal income tax (thousands)	Approximate U.S. effective tax rate on world wide incom (per cent)
Mobil Oil Corp.	3,034,528	721,377	12,600	01.8
Texaco, Inc.	1,223,599	346,291	32,000	09.2
Standard Oil Co. of California	782,465	247,505	70,200	28.4
Shell Oil Co.	867,729	866,475	312,081	36.0
Atlantic Richfield Co.	828,622	498,598	70,100	14.0
Union Oil Co. of California	441,332	309,532	70,200	22.7
Standard Oil Co. of Ohio	178,868	154,339	6,539	04.2
Amerada Hess	324,476	161,001	29,864	18.6
Marathon Oil	457,327	207,786	74,000	35.6

Viewed in another manner Zeifman and Ainsworth in their report point out the difference between net income reported to stockholders (book income) and federal taxable income for 10 of the 13 major oil corporations doing business in Alaska. The differences showed that the book income figures (income reported to shareholder) exceed taxable income by \$1.6 to \$3 billion dollars a year.

We reproduced here a table from the Zeifman and Ainsworth report showing the difference between book income and taxable income for the sample of oil companies operating in Alaska.

DIFFERENCE BETWEEN BOOK INCOME AND TAXABLE INCOME
FOR A SAMPLE OF OIL COMPANIES OPERATING IN ALASKA

<u>Company</u>	<u>Difference 1973 (thousands \$'s)</u>	<u>Difference 1974 (thousands \$'s)</u>	<u>Difference 1975 (thousands \$'s)</u>
A	NA	221,219	38,825
B	177,629	208,882	129,451
C	NA	NA	17,009
D	39,814	34,204	NA
E	166,769	242,587	150,231
F	193,072	368,175	110,248
G	NA	NA	464,781
H	335,080	448,695	608,333
I	84,495	93,351	NA
J	(61)	(333)	72
K	NA	46,338	(120,374)
L	261,888	280,454	NA
M	278,634	784,519	193,439
Total	1,834,298 (4 cases not available)	3,056,434 (2 cases not available)	1,592,015 (3 cases not available)

Thus it can be demonstrated that the federal tax base has been substantially eroded, especially for the oil industry. It is this eroded tax base which Alaska has relied upon for its corporate income tax revenues.

1-A. Conflicting policies. In addition to the dollars-and-cents problem of incorporating the eroded federal tax base as the State's income tax base, there is a question as to the desirability or wisdom of adopting federal tax policies as Alaska's own by incorporating the federal tax base. As explained earlier, federal tax laws are not designed solely for revenue raising purposes, but for other economic and social policy reasons as well. These federal policies may not always coincide with Alaska tax and revenue policies. By incorporating, however, these federal tax provisions, the Alaska Legislature has in a real sense delegated to the U.S. Congress State policy-making, as reflected through various tax measures.

A prime example of how federal and State taxing policies may conflict is shown by the federal tax exemption for domestic international sales corporations (DISC). Under Internal Revenue Code Section 991, an exemption from taxation is provided for certain export companies that do a significantly large part of their business through exporting American goods overseas. This tax exemption was given to promote a desired federal fiscal goal - a favorable balance of payments

position for the United States. Unfortunately, this exemption flies in the face of Alaskan policies and revenue concerns. First of all, no State tax incentive is needed to encourage the export of Alaska products because there is a high demand for them. Second, it is not always clear that overseas export of our natural resources should be encouraged. Third, it seems especially inappropriate to exempt from State taxation those companies which do export Alaska resources and provide no income tax return to the people of the state for the extraction of those resources. 10/

Although this is only one example of many, it points to a particular problem of incorporating the federal tax laws in total. If Alaska wants to encourage certain types of development or certain industries through its tax laws the State may be thwarted by federal tax provisions working at cross purposes. On the other hand if State policies dictate the denial of incentives or subsidies in certain circumstances, Alaska may find itself unwittingly providing those incentives through its adoption of the federal tax base.

1-B. The non-responsive erosions. Besides adopting federal policies that may be irrelevant to Alaska's needs (thereby needlessly eroding the State's tax base) or which even conflict with State policies and objectives, incorporating the federal tax base may only clumsily advance Alaska's

interests even when its policies are the same as the federal policies. A Congressionally given incentive may or may not reflect benefits to Alaska, since the federal policy is not limited in application only to Alaska. This was specifically pointed out by Zeifman and Ainsworth in their report. 11/

...it is important to note that the tax incentives and tax subsidies granted to corporations by Congress are not limited in a geographical sense to activities that relate to particular States. For example, the provisions of the Internal Revenue Code which allow petroleum companies to expense, rather than capitalize, intangible drilling costs have the effect of encouraging the corporation to engage in drilling activities in any state or foreign country in which it may choose to operate. Thus, if the corporation is doing business both within and without Alaska, the tax expenditures made by Congress can be used for non-Alaskan drilling.

In other words, since Alaska has simply adopted the relevant provisions of the Internal Revenue Code, Alaska, in effect, offers the same type of tax incentives to develop non-Alaskan wells as Alaskan wells.

Thus even when federal and state policies coincide, federal tax incentives will not necessarily benefit the Alaskan economy. The federal incorporated incentives only serve to drain potential state income tax revenues without offsetting economic benefits.

1-C. Recent recognition of the problem. Both the Department of Revenue and the Alaska Legislature have recognized the problems of incorporating the federal tax base and

responded to it on a small scale for income taxpayers generally during 1975 and 1976.

For example, in 1975 the State income tax law was amended to disallow the foreign tax credit, which is applicable at the federal level to avoid double taxation of the same income by two national governments. 12./ The application at the state level is inappropriate. A limitation of \$500,000 on the amount of qualifying investment credit property was also adopted in 1975. 13./ This limitation gave a sizable amount of investment credit incentive to most businesses while insuring that the Alaska tax credits were not subsidizing investment property used elsewhere. In addition, several items in Congress's Tax Reform Act of 1975 were disallowed because of adverse impacts which they could have had on State revenues. These items included: special refund of 1974 income taxes, personal exemption credit, earned income credit, and the \$2,000 credit for purchase of a new principal residence. 14./

In 1976, recognition of the same problem was again dealt with, but in a broader stroke. The State income tax statute was amended to provide that changes in credits or exemptions passed by Congress would not be incorporated by reference into Alaska law until the second January 1 following the effective date of the federal law. 15./ Thus the Alaska Legislature would be given at least one full

legislative session to decide whether a particular federal exemption or credit should be applicable for Alaska. Only exemptions and credits have this "hold" before taking effect for the State income tax since they have the greatest potential revenue impact.

Thus the problem of federal incorporated tax base has been recognized and has been partially dealt with over the past few years. Even though these changes have helped, they are insignificant when compared to the multitude of federal tax incentives and subsidies that are still incorporated into the State's tax. Except for the disallowance of the foreign tax credit and the limitation on investment credit, oil industry incentives and subsidies have virtually remained untouched.

Untying the Alaska corporate income tax from the federal definition of taxable income for oil companies would appear to be long over-due. This action would not only increase the tax base, but would also allow Alaska to decide for itself which sort of tax incentives should be allowed. For example, the Legislature might decide that it wanted to allow percentage depletion or excess depreciation, but only with respect to Alaska based properties. In any event the decision would be based upon what is best for Alaska, rather than having taxing policies made by the U.S. Congress.

2. Alaska's share of the tax base. The other problem area in the corporate income tax area is the assignment of income to Alaska by oil and gas corporations.

As discussed earlier in Chapter II of this report, if a corporation conducts all of its business in the state, it assigns all of its income to Alaska. If, however, a corporation conducts its business in at least one other state, its business income is assigned to Alaska based upon the three factor formula set out in the UDITPA provisions. 16/ It is this assignment of income of multistate or multinational companies that presents the problem.

The three factor formula assumes that property, payroll and sales equally contribute to the earning of income by a corporation and that the total income of a corporate business can be divided among the taxing states in proportion to each state's share of property, payroll and sales. Theoretically it does. Any formula to apportion income by its very nature is arbitrary; however a three factor formula of different elements will tend to equalize the distortions of any particular factor. In addition, the more uniform the formula, the more the distortions of income are equalized from state to state.

This uniform three factor formula works best for general mercantile business in which property, payroll and sales

contribute equally to the earning of income in the states where they operate. For them the three factors are, for the most part, accurate representations of the taxpayers' activities in each state. For example, retail department stores are probably best apportioned on the basis of the UDITPA formula of property, payroll, and sales.

To determine whether the formula accurately represents the amount of an oil and gas corporation's activity in Alaska, it is first necessary to examine each of the factors in the formula.

As explained in Chapter II, the property factor is the combination of owned property included at its original cost and rented property included at eight times the annual rental rate. These property units are assigned to the various states on the basis of the physical location of the property. Property under construction, however, such as the Trans-Alaska Pipeline, is not included in the property factor until it has been completed. Therefore real and tangible personal property of oil and gas companies physically located in the state are assigned to Alaska's numerator at actual cost. Other real and tangible personal properties leased by the companies and physically located in the state are also assigned to Alaska's numerator at eight times their annual rental rate.

The payroll factor is the accumulation of employee compensation earned within the state. Generally, an employee's wages are assigned to a state's numerator if the wages were earned in the state. The rules change somewhat if the employee worked in more than one state. If that occurs, then the payroll is assigned to the state where the work was directed or controlled. Thus, only the wages of oil and gas corporation employees which were actually earned in Alaska are assigned to the Alaska payroll numerator.

The sales factor is first an accumulation of the total sales price of all of the business's sales. Sales of tangible personal property are attributed to a state on the basis of the destination of the products sold. Sales other than sales of tangible personal property are assigned to the state where the income producing activity is performed. Thus if the ultimate sale of oil and gas products to consumers is made in Alaska, those sales are assigned to Alaska's numerator.

Although there are problems with each of the three factors, the use of the uniform sales factor produces the greatest distortion of oil and gas corporation activity in Alaska. That is, the total value of petroleum products is assigned only to the state where the final destination sale is made. No value is assigned to the state where the petroleum is produced. Instead of prorating that value

added to the final product by the various phases of the business, the destination sales factor gives sole weight to the marketing side of the business.

Zeifman and Ainsworth also point out this deficiency in their recent report and describe it as follows: 17/

...the present apportionment formula operates in such a way as to reduce the amount of taxable income attributable to Alaska by corporations which extract non-renewable petroleum resources from the State. This effect occurs largely because the Uniform Division of Income for Tax Purposes Act contains a "destination-oriented" sales factor, in which sales of Alaskan oil are generally assigned to Alaska only with respect to petroleum products which are ultimately consumed in the State. As a result, the exportation of petroleum from Alaska has the effect of reducing the tax liability of the extractor of the Alaska petroleum.

Thus not only does the destination sales factor reduce the income tax revenues of the State, but it completely fails to measure the value of oil produced within it.

B. PROBLEMS WITH THE PRESENT OIL AND GAS PRODUCTION TAX

This section identifies certain problems that have been observed with the present production tax and other problems which may arise if it continues unchanged. Part 1 discusses the general nature of production taxes and their relative economic effect (compared to other factors) on commercial enterprises engaged in developing and exploiting petroleum resources. Part 2 focuses specifically on Alaska's existing oil production tax and explores where it may be deficient. Part 3 is an examination of petroleum-related revenue problems that could develop as the result of efforts to artificially depress the price of Prudhoe Bay oil below its market value. Part 4 reviews the existing natural gas production tax and describes its current deficiencies.

1. The general nature and economic effect of petroleum production taxes. A production tax is a tax imposed on the activity of producing one or more taxable substances, such as oil and gas. Typically production taxes do not reflect the expenses incurred to obtain the production. The tax is either some specified percentage of the gross value of the production or a flat fee of so many cents per unit of production. Since it is not based on net proceeds of the production operation, the production tax simply represents another cost of doing business to the producer.

There would seem to be two ways a production tax could affect the producer's decision-making: first, when the producer is deciding to invest in unknown acreage (i.e., when the bonus bids are made) and later, when the producing property is approaching the end of its economic (profitable) life.

Perhaps surprisingly, the production tax is often relatively unimportant in the evaluation and ranking of petroleum prospects by bonus bidders. The process to prepare and make a bonus bid is a concerted team effort intended to see far into the future. The finest available geologists, engineers, mathematicians and other experts examine the variables which significantly affect the profitability of production from a potential reservoir. Risk-adjusted estimates are made to answer these paramount questions: (1) What will the company receive per unit for the production? (2) How fast will the reservoir produce? (3) How much can be produced in total? (4) How much capital will be needed to develop the pool if it proves to have oil or gas? (5) How effectively will others bid for the same acreage? and (6) How does this prospect compare to other prospects in which the company might invest? Discounted cash flow analyses play an important role in this decision-making.

The effect of discounted cash flow analysis is to emphasize the importance of front-end costs and early profits: occurrences 10 or 15 years down the road have very little

impact on the picture presented by the earlier cash flows, even though the later occurrences are of major magnitude. During the early years when production is flush and profit margins are at their widest, the business cost reflected by a production tax is often slight compared to the profit margin. Even though the profit margin will be narrowed through time so that the production tax takes on greater significance, this will be far in the future. The economic attractiveness of the early years remains unaltered. Thus the production tax can play a rather minor role in the decision-making except for the evaluation of marginally attractive prospects. 18/

Once a discovery has been made and production begins, however, the production tax (and the landowner's royalty) can have a more significant impact on the economics of the production operation and the associated decisions. As operating costs rise during the life of the field, the profit margin shrinks. At some point the total production costs overtake the value of the oil or gas produced, and production can then be continued only by operating at a loss. As one of the costs of doing business, the production tax contributes to the total costs and tends to hasten the time when this break-even point (called the economic limit) is reached. The royalty to the landowner has a similar effect.

To illustrate how a production tax and the landowner's royalty affect the economics of production operations, a

simple hypothetical Field "A" has been set out as an example below. This producing field consists of 10 oil wells. Notice that in each of the fifteen production years shown, the wells produce more in terms of fluid volumes than they produce in crude oil. This is because oil wells usually produce significant quantities of salt water brine. As the ratio of water to crude oil increases, the cleaning and dehydrating of the total fluid stream becomes increasingly expensive, especially on the basis of the cost per barrel of oil. In the first years shown, most of the fluid flow from Field "A" wells is crude oil. During Year 2, the 10 wells average 5000 barrels of oil and 1000 barrels of salt water brine per day. Seven years later in Year 9, out of 7800 barrels of fluid produced each day, only 1300 barrels are crude oil. This is to say that five barrels of brine are produced for each barrel of crude oil recovered. It is readily apparent that the first years of producing operations are far less difficult than the last few years.

PRODUCTION ECONOMICS FOR HYPOTHETICAL FIELD "A"

Year	Total Fluid B/D	Total Oil B/D	Operating Expense \$/B	Capital Expense \$/B	Combined Expense \$/B
1	4000	3500	.23	.16	.39
2	6000	5000	.21	.11	.32
3	6700	4500	.32	.12	.44
4	7000	4000	.42	.14	.56
5	7300	3200	.76	.17	.93
6	7500	2560	1.21	.21	1.42
7	8100	2050	1.95	.27	2.22
8	7800	1650	2.61	.33	2.94
9	7800	1300	3.52	.42	3.94
10	7600	1150	4.44	.52	4.96
11	7400	1000	5.31	.62	5.93
12	7400	900	6.36	.68	7.04
13	7400	800	7.67	---	7.67
14	7200	700	9.19	---	9.19
15	7000	600	11.20	---	11.20

The effects of production tax and royalty can be perceived when a value is given to the production of Field "A". For simplicity, assume there is a constant nominal price of \$6.00 a barrel during the production life. With a one-eighth royalty and a five percent tax on the producer's share of production, the cost per barrel for the royalty is \$0.75 ($\$6.00 \times .125 = \0.75) and the tax on \$5.25 value ($\$6.00 - \$0.75 = \5.25) of the producer's share is 26.25 cents. This leaves about \$4.99 per barrel to cover the combined operating and capital costs. In Year 10 those combined costs are \$4.96, suggesting there would be little production after the tenth year. Of course, near the end of the productive life the capital expenditures would be reduced or discontinued. But in this example the operating costs alone rise to \$5.31 in

the next year, so the life would not be materially extended by the cessation of further capital investments in Year 10.

In the absence of the royalty and tax costs, the producer would have the full \$6.00 available to cover operating and capital expenses. Combined, those costs are \$5.93 in Year 11, meaning the field would be produced all of that year and part of Year 12. Again, with the discontinuation of capital expenditures, the operation could be extended farther into Year 12 until the operating expense exceeded \$6.00 a barrel. In other words, about a year would be added to the life of Field "A" if there were no production tax and royalty. Graphically, this may be shown as follows:

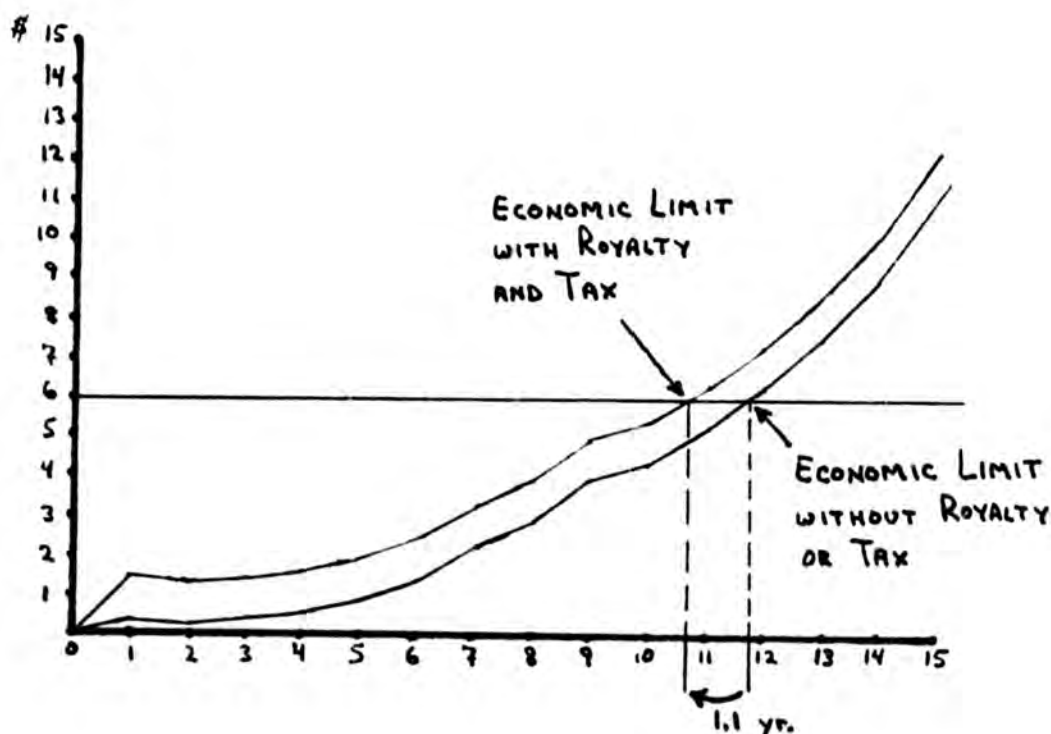


Figure V-1

To put the economic effects of royalty and production tax payments into perspective, it is useful to consider the effects of federal price controls. There are two major controlled price categories for U.S. oil, "old oil" and "new oil." ^{19/} The national average price for these two "tiers" is \$5.15 and \$12.40, respectively, which are significantly below their true market value of roughly \$13.80 (the cost for imported oil).* By depressing the price below the market

* It may be contended that the present world market prices are artificially heightened by the actions of OPEC and do not reflect what a "true" market price would be. This reasoning is specious at two levels of analysis. First, the OPEC price is what must be, and is being, paid in order to obtain OPEC oil. It is not a phony price, but one that is actually paid every day for millions of barrels of oil. Second, and more fundamental, is the fact that land, and the resources beneath it, are as equally entitled to receive scarcity value for their economic contribution as labor and capital. If there were unrestricted access to unlimited amounts of capital, competition would drive interest rates down to zero. Similarly, unlimited availability of labor would reduce wages to a minimum subsistence level. Given the scarcity of both capital and labor, interest rates are not zero and labor is not paid the minimum subsistence wage. By the same token, then, land and its resources should realize their scarcity value. Moreover, there is a sound reason to allow that scarcity value to be realized. The price of a resource should not be less than the economic cost for the last, most expensive increment to the supply that meets demand. Lower prices for lower-cost portions of the supply distort the demand and result in a misallocation of resources to that supply. At present, the alternatives to OPEC oil are synthetic crude, shale oil and oil from tar sands. The costs for these alternative sources are yet higher than the present level of OPEC pricing, implying that OPEC oil is in fact still underpriced and that its prices can actually be increased in real terms (i.e., in terms of dollars of constant buying power). OPEC will have raised its price too high if it exceeds the cost of one of the alternative sources and that source cannot be brought into the market immediately.

value, the federal price controls impose an artificial economic system on the crude oil producer. The limitation on the price for oil reduces the gross income that can be obtained by producing that oil, and the point where expenses overtake the permitted income is advanced from the true economic limit. This effect is especially acute when the production is mostly "old oil."

As an "old oil" producing property reaches the pseudo-economic limit imposed by the low "old oil" price, the production will be allowed a measure of pricing relief by allowing enough of it to receive "new oil" prices so as to return the producer to the same level of profitability that he had for that property in May 1973. As production costs continue to rise, this policy will eventually lead to the producer's entire share of production of the property being priced at the "new oil" prices. However, there is no increase allowed for the royalty owner's share, on the rationale that affording pricing relief to the royalty owner does not affect the production economics of the property. 20/ The effect of this is that the federal price controls, when confronted by a loss of production when a property reaches its pseudo-economic limit, will attempt to reset the pseudo-economic limit at ever higher price levels. The apparent maximum to this adjustment of the pseudo-economics is the pseudo-economic limit at the "new oil" price.

These economic and pseudo-economic effects can be illustrated in their application to hypothetical Field "A". Assume that "A" is in Cook Inlet producing "old oil" with a controlled price of \$4.855 (as most of Cook Inlet oil in fact is priced, for 34° API gravity oil). The royalty share, if based on this depressed price, represents a 61 cent cost ($\$4.855 \times .125 = \0.606875 , rounded to \$0.61). The cents-per-barrel tax of \$0.3463 applies at "old oil" prices to seven-eighths (the non-royalty share) of the barrel, representing a cost of 30 cents per barrel produced. At "new oil" prices the tax is 54.25 cents ($\$12.40 \times .875 \times 5\% = \0.5425). The combined per-barrel cost of the tax and royalty is 91 cents at "old oil" prices and \$1.15 with "new oil" pricing (no pricing relief would be given to royalty oil under prevailing federal policies).

The following graph plots the operating cost curve and the curve for operating costs plus royalty and tax. No capital costs are included because capital expenditures will be terminated when the costs approach the various price levels where price-controlled revenue equals total costs. Notice how the federal price controls create pseudo-economic limits well before the true economic limit based on real market value. By comparison the economic effects of the production tax and royalty are small.

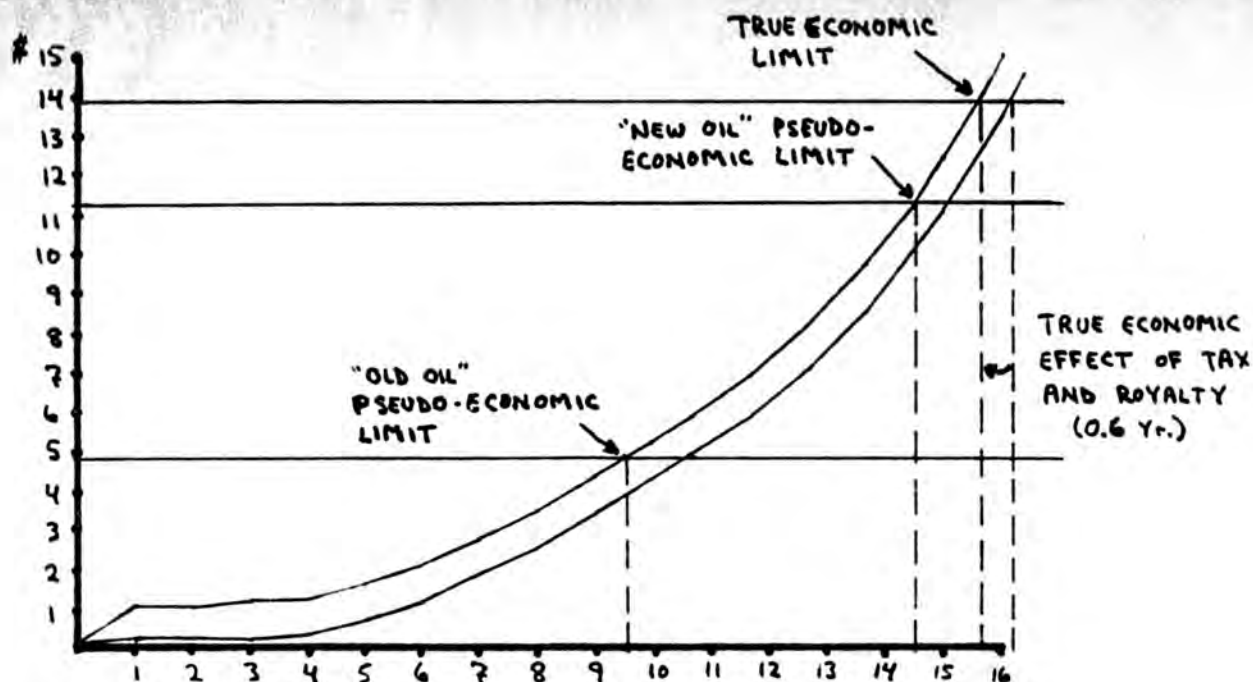


Figure V-2

2. Specific deficiencies in the present oil production tax. The existing State of Alaska crude oil production tax contains two flaws which should be and can be corrected. The first problem area concerns the present "stair steps" production tax rate schedule which establishes higher tax rates according to the productivity of individual oil wells. The second deficiency is related to the first and pertains to current difficulties in administering crude oil production tax collections. Each of these flaws can be remedied with relative ease. The result would be to create a more efficient and equitable oil production tax system.

The current State oil production tax contains a "stair step" feature which is intended to alleviate the adverse im-

pact that a production tax can have on an oil well operating close to its true economic limit. As was shown earlier with the Field "A" example, total operating and capital costs, together with royalty payments and production taxes, will ultimately rise to a point where profitable production operations based on true value can continue no longer. At this point the true economic limit has been reached and operations cease. The "stair step" feature of the existing oil production tax schedule is an attempt to reduce the tax rate as production falls closer to the true economic limit. The tax rate declines from 8% to 6% to 5% as individual well output falls. Unfortunately, the current "stair steps" appear to be sized incorrectly.

Economic factors governing production operations vary widely in the State of Alaska. Some areas in the State are located close to the refinery market and have low operating costs. In these areas wellhead values are high. As a consequence, the true economic limit (measured in barrels per day) for these properties can be quite low: 50 to 75 barrels a day per well, or even lower, in some cases in Cook Inlet.

Other crude oil wells in Alaska are not located close to refinery markets and could have extremely high operating costs. The netback value in the field for these isolated areas is lower than in Cook Inlet and the operating and capital costs can be much higher than in Cook Inlet. Accord-

ingly, the true economic limit (measured in barrels per day) for these producing properties can be quite high. Depending upon the property, this limit might range from 300 to perhaps 1000 barrels per day. There is, then, a rather wide range of values which can be generated regarding the minimum production level at which Alaska crude oil wells can be operated.

From this perspective, an economic flaw in the existing or any other "stair step" production tax schedule becomes obvious. By establishing a fixed schedule of "stair stepped" tax rates, the State crude oil production tax is based on the faulty assumption that production economics are similar in Cook Inlet, Prudhoe Bay, and everywhere else in Alaska.

This is not so. Diligent analysis at specific intervals may possibly produce a statewide "stair step" tax rate schedule which is consistent with the public interest as of the time of that analysis. As economic factors change, however, static systems such as the current one fail to adjust, and the "steps" will become inappropriate for Alaskan production.

A second problem area in the current State crude oil production tax concerns administrative difficulties. Under the current statutes, oil production taxes are collected on the basis of individual oil well productivity. Unfortunately, well tests are only performed periodically. Moreover, actual

crude oil flows are not metered for individual wells between well tests. As a consequence, individual well production must be allocated to specific wells on the basis of the periodic well tests. These tests may or may not be witnessed by State personnel. Since well conditions change through time, the accuracy of any particular well test cannot be verified by later testing. 21/ As a result, a complete audit of production tax payments is impossible due to lack of documentation. 22/ This administrative difficulty would be eliminated, however, if production taxes were based on averaged well production per producing property rather than the current well-by-well basis.

3. Protecting production tax revenue against manipulated oil prices. While the preceding section discussed the effects of the present production tax on the economics of oil production, the focus here is on the effectiveness of the tax as a reliable source of revenue for the State and on its safeguards against possible actions that would jeopardize that revenue. The greatest of those dangers is the manipulation of oil price, especially in regard to North Slope oil. There are basically two parties that might want to manipulate the price of Prudhoe Bay oil. One is the oil companies themselves, by inflating transportation costs and similar changes in order to lower the field price of the oil on which the tax is based. The other is the federal government, through price controls. In this section the various means available to the oil companies

are first discussed, along with the present safeguards against this. Then the present price control structure and the mechanics of the federal pricing decision for Prudhoe Bay are addressed, followed by an examination of the present tax's ability to deal with federal actions for North Slope and Cook Inlet oil production.

3-A. Corporate actions affecting price. To varying degrees some companies can retain control of their oil from the time it is produced until it is retailed as refined products. A company having this control is said to be vertically integrated. A vertically integrated company can, in a very real sense, choose which of its integrated operations - producing, transportation, refining or marketing - will be carried on the books as break-even or losing operations and which will be the sources of the profits of the overall enterprise.

A company's competitive position in one phase of operations can limit the extent to which income may be shifted to, or away from, that phase. Another influence can be royalty and production tax payments. If the field price 23/ of an integrated producer's production can be lowered as the result of shifting booked profits from production to some downstream phase of operations, the overall enterprise would lose nothing by doing so since it is merely moving money from one pocket to another. In fact it would actually have a net

gain since the lowered field price means that less royalty and production tax have to be paid.

Obviously decisions regarding the profitability of an integrated company's various interrelated activities would be made on the basis of many other factors besides the possible effects on royalty and production tax payments. Yet a company would be unlikely to fail to take advantage of an opportunity to realize royalty and production tax savings when that opportunity arises, even though entirely different considerations led the corporation to structure itself initially in the manner that now allows it to take advantage of the opportunity.

There seem to be three possible opportunities for some, but by no means all, of the companies owning interests in the Prudhoe Bay field to realize most or all of the benefits from the prevailing prices in the world oil market so dominated by OPEC while holding the line, so to speak, on production tax and royalty for that oil. These are in setting the TAPS tariff (or tariffs), in marine transportation costs and in marketing the oil to refiners outside the West Coast area. To some extent the State has protected its revenues against corporate actions in these areas, but there are serious gaps and weaknesses in that protection.

The danger most commonly perceived regarding TAPS is that excessive costs may be included in the rate base. The Interstate Commerce Commission (ICC), which regulates tariffs for crude oil pipelines in interstate commerce, is in the process of reviewing its tariff-setting procedures. This may be a positive step forward in terms of identifying excessive costs and eliminating them from the rate base, although the ICC's history of rate-making for pipelines may only lead one to a guarded optimism for the results of that review.

Anticipated to be a more diligent watchdog for Alaska's interests, the Alaska Pipeline Commission has authority to regulate TAPS tariffs to the fullest constitutionally permissible extent that it can do so. 24/ A risk remains, however, of pre-emption by the federal government. Moreover, even if not totally pre-empted, the Alaska Pipeline Commission would not regulate tariffs for oil moving in interstate commerce.

A question therefore arises if both agencies have rate-making powers regarding TAPS: Because the tariffs on file with either agency are prima facie reasonable under AS 43.55.150 for purposes of ascertaining value for production tax purposes, which tariff - the one filed with the ICC or the one with the Alaska Pipeline Commission - should be used for that purpose? Or, should each be used, for interstate and

intrastate shipments, respectively? A further complication comes from the fact that TAPS is a common facility for eight different pipeline companies, each with its own financial situation. It could well be that eight different tariffs will be filed with the ICC, while the Alaska Pipeline Commission might have eight more different tariffs. Which tariff or tariffs should be used then for valuation purposes under AS 43.55.150? Although the statute does not itself answer these questions, the Department of Revenue will be proposing draft regulations to deal with them at approximately the same time this report is published, and public hearings on the proposals will be announced for March.

Tankers may also afford some companies an opportunity to affect the field price for Prudhoe Bay oil. Some have chartered tankers to transport their oil from Valdez, but others may use their own ships. The inter-affiliate billings in the latter case would be subject to review by the Department of Revenue under AS 43.55.150 to prevent abuses and ensure that only reasonable costs of tanker transportation are recognized in the value of Prudhoe Bay oil for production tax.

The third opportunity results from the surplus of crude oil available to refiners on the West Coast that is expected to develop shortly after Prudhoe Bay production reaches 1,200,000 barrels a day. Much of this production will be refined on the West Coast. The surplus oil will have to

move to more distant U.S. refineries, if it is not sent to Japan in exchange for other oil shipped to U.S. ports on the Gulf of Mexico or Atlantic seaboard. The extra distance for that oil to move means greater transportation costs can be netted from the sales price at its destination to develop an implied price for the oil back at Prudhoe Bay. This means the field price will probably be lower for surplus Prudhoe crude than for the large amounts of Prudhoe oil that will be refined in West Coast refineries. A producer able to market only part of its Prudhoe Bay oil to its own refineries or others' on the West Coast can contend, quite persuasively, that traditional principles of economics limit the field market value of its entire share of production to that lower field price which is implied from the sales of the surplus crude oil marketed elsewhere at greater cost.

At present the State's only sure protection of its production tax revenues against reduction of the value due to the West Coast oil surplus would be the cents-per-barrel tax, which guarantees that production tax income will not fall below a specified level regardless how low the field price may go. Unfortunately, the latest cents-per-barrel rates protect the tax against reductions in the field price below \$6.10 25/ while the likely free-market field price (netting back from crude oil prices at West Coast refineries) will be substantially higher than this. Thus considerable production tax revenue would be foregone before the cents-

per-barrel provisions could begin protecting that revenue from further diminution.

3-B. Federal price controls, or, "Congress and the Teeter-totter". By April 15 of this year a decision will be made that is of far greater importance to Alaska than any corporate decision to take advantage of some opportunity to reduce its royalty and production tax payments to the State of Alaska. This is the decision regarding the pricing of all North Slope oil transported by TAPS. It will be made by President Carter and will be submitted on that date to Congress. 26/ The President's decision will become effective after 30 days unless either House of Congress rejects it within that time. 27/

Before proceeding directly to a discussion of the President's options and the standards he will apply in making this decision, it is helpful to explain how the present federal price controls apply to U.S. production other than that of the North Slope and then to explain how the decision regarding the North Slope oil interrelates to the price controls for the rest of domestic production.

Prior to the enactment of the Energy Policy and Conservation Act late in 1975, 28/ oil price controls created three categories of oil production. There was "old oil," "new oil" and "released oil." "Old oil" was first frozen

at its price level of mid-1973, but all "old oil" was allowed an increase of one dollar a barrel in December 1973. "New oil" and "released oil" were not controlled and were free to rise to market price levels, which rose rapidly because of OPEC price actions and the Arab oil embargo.

An apparent purpose of that pricing policy was to encourage increased domestic production by allowing the actual amount of the increase ("new oil") and an equal amount of the historic level of production ("released oil") to rise to the unexpectedly high market prices demanded by OPEC. To ensure that overall production from a property actually increased, the price controls specified that, for each month a property failed to produce the amount of oil as it did in the same month in 1972, the amount of this shortfall would be carried forward and deducted from any later months' increases until the shortfall was fully offset by those increases. Only when all past shortfalls were fully offset could production from the property be classified as "new" or "released" oil and receive higher prices.

By December 1975 these high, or "upper tier," prices were ranging from \$12 to \$14 a barrel. There was a range for "old oil" prices, too, since the "old oil" of each property was frozen at the actual mid-1973 price (plus the \$1.00 increase allowed in December 1973) for that

property's oil. Although \$5.25 was widely quoted as the "old oil" price, it was only the estimated average of all "old oil" prices. Some "old oil" was in fact frozen at a higher price; others were priced lower. ^{29/} The overall average price was reported to be \$8.75. Graphically, the pattern of prices for U.S. production by the end of 1975 looked like this:

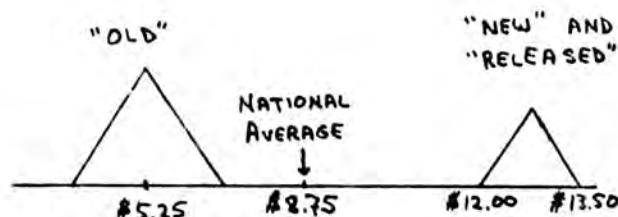


Figure V-3. The way we were.

With the enactment of the Energy Policy and Conservation Act, Congress changed this picture dramatically. Suddenly the whole pricing structure was transformed into an enormous teeter-totter, to be balanced on a reduced national average price of \$7.66 that Congress had chosen.

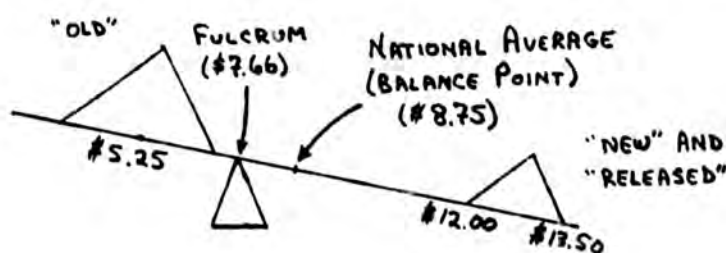


Figure V-4. How Congress built the teeter-totter.

Having decreed where the fulcrum must be, Congress left to the President and FEA the task of restructuring domestic oil prices so as to balance the teeter-totter on its new fulcrum. To assist in this, Congress extended price controls to "upper tier" crude oil.

The determination of "upper tier" oil was simplified by no longer offsetting accumulated monthly shortfalls before production could receive "upper tier" price. "Released crude" also ceased to be a category. Instead, "new oil" became simply that part of the monthly production from a property that exceeds the property's "Base Production Control Level" for that month, which is simply based on the amount of "old oil" the property produced during a particular reference period.

FEA and the President had from December 1975 to February 1, 1976 to accomplish the restructuring. 30/ They extended the two tier pricing system, holding the "lower tier" at \$5.25 and lowering "upper tier" prices so they averaged \$11.28. 31/

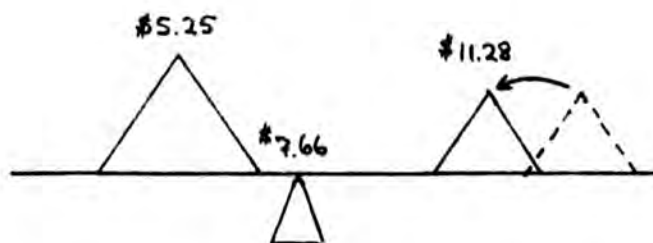


Figure V-5. How the President and FEA balanced the teeter-totter in February 1976.

Having struck this initial balance, FEA and the President had the further task of keeping the teeter-totter balanced while the fulcrum increases monthly at an annual compound rate to 10 percent. ^{32/} They began doing this by allowing both "upper tier" and "lower tier" prices to rise month by month under the following schedule:

	"Old Oil" Increase over 2/76 Level	"New Oil" Increase over 2/76 Level
February 1976	--	--
March 1976	\$0.03	\$0.07
April 1976	0.06	0.14
May 1976	0.10	0.21
June 1976	0.13	0.27

By June 1976, however, it became apparent that the 60:40 of "old" to "new oil" that had been assumed was in fact erroneous. Instead, there was a larger proportion of "new oil," which meant the actual balance point had moved ahead of where it should have been under the schedule ordered by Congress. To correct this FEA suspended its planned price increases, holding the prices for both tiers at the June levels until the scheduled balance point caught up with the actual one.

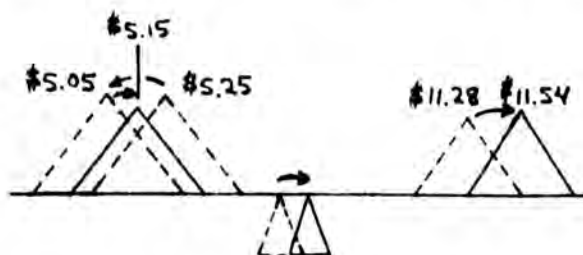


Figure V-6. How "old oil" was corrected to \$5.05 and how both tiers shifted upward by June 1976.



Figure V-7. The teeter-totter with "old," "new" (\$11.60) and "stripper" (\$11.63, but actually decontrolled) oil.

Unfortunately all this rebalancing did not help the actual balance-point get back within the 10 percent-a-year schedule that Congress prescribed for it. Under the law, any period in which the actual balance-point exceeds the schedule must be offset by a period in which the actual balance-point is below the schedule. 36/ Consequently FEA first extended until November 1976 the "hold" on escalating the basic "old" and "new" oil prices, then indefinitely. Finally, in January 1977, FEA announced a three-month roll-back of "new oil" to \$11.40 and "old oil" to \$5.15 (reducing the balance from \$8.34 to \$8.30) to compensate partially for the period when the actual balance-point exceeded the 10 percent-a-year schedule. To compensate for that period completely, the roll-back would have to extend until July 1977. However, FEA announced a shorter roll-back period because Congress will be reviewing the entire crude oil pricing teeter-totter this March. 37/ In addition the pricing of North Slope oil will be submitted to Congress by the President before the end of the currently announced roll-back period.

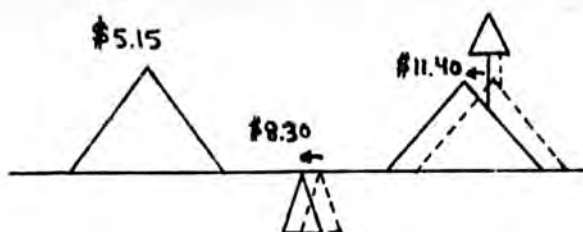


Figure V-8. The latest rebalancing, January 1977.

At this point it is appropriate to return to the matter of the pricing of Prudhoe Bay crude oil. The basic decision to be made is whether that oil should be put on the teeter-totter with the rest of U.S. production or whether it should be kept off and regulated separately.

The biggest factor affecting this decision is whether the price in the field for that oil is higher or lower than the balance-point of the teeter-totter. If its field price is lower than the balance point, the inclusion of that oil on the teeter-totter will mean that some oil currently in the "lower tier" can be allowed to receive "new oil," or possibly even decontrolled, prices.

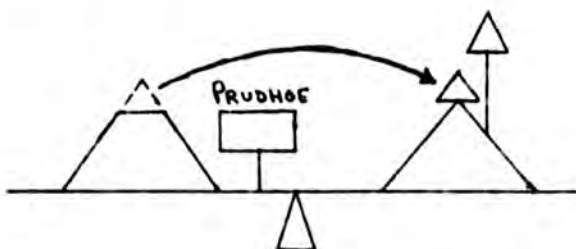


Figure V-9. How including Prudhoe oil could allow pricing relief to "old oil" while still balancing the teeter-totter.

On the other hand, if the field price of North Slope oil is greater than the balance-point, its inclusion would make the balance-point exceed the 10 percent-a-year schedule, and there would have to be another "hold" to allow the scheduled point to overtake the actual balance-point or else some of the "new oil" would have to be lowered in price.

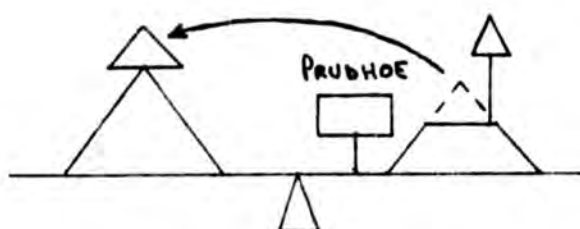


Figure V-10. How some "old oil" might be reclassified to maintain balance if North Slope oil is included and is above the balance-point.

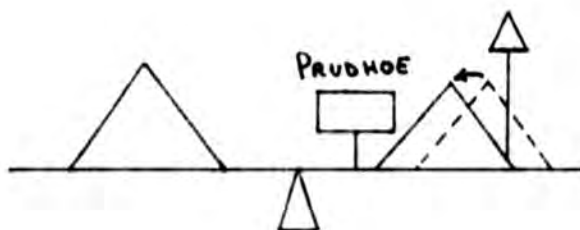


Figure V-11. How all "new oil" might be rolled back to maintain the balance if North Slope oil is included and is above the balance-point.

If such a "hold" or a lowering of oil prices proved to be slight, the President could keep Prudhoe oil on the teeter-totter even though its price were above the balance-point. However, if the President determines that keeping it on the teeter-totter

would...have the effect of reducing or limiting ceiling prices permitted for crude oil produced in the remainder of the United States to levels which would result in less production of such crude oil than would otherwise occur,

then he may recommend excluding it and subjecting it separately to price ceilings no higher than the "highest actual weighted average first sale price...for significant volumes of any other classification of domestic crude oil." 38/

It would be best for all concerned if the free-market field price for North Slope oil turns out to be less than the balance-point price (\$8.40 through April). In that case some "old oil" could be given pricing relief to keep the teeter-totter in balance, as illustrated in Figure V-9 above. This relief could be given in a way that encouraged marginal or high-cost production. At the same time, the free-market price for North Slope oil would, to the maximum extent short of subsidies, "provide positive price incentives for the development of [North Slope] crude oil production." 39/ It is likely that the free-market field price for Prudhoe Bay

oil will prove to be below the balance-point of the teeter-totter because of the high costs of transporting it to the refineries. 40/

It is not a sure thing, however, that the President and FEA will decide that a free-market price is necessary to provide adequate "positive price incentives" for North Slope oil development. Instead, it could be decided that a controlled price at a level below that of the free market yet high enough to provide a "fair" rate of return on North Slope investments provides the necessary "positive price incentives." With such a controlled price, putting Prudhoe Bay oil on the teeter-totter 41/ would allow an even greater upward shifting for other oil prices than there would be from the inclusion of Prudhoe oil at its free-market price.

In light of this possibility is is little comfort, from Alaska's perspective, to learn that a study has already been done for FEA about the range of prices that would yield a "fair" rate of return (discounted cash flow basis) on investments in the exploration, acquisition, development and pipeline transportation of North Slope oil. 42/ It concludes that a price as much as \$0.90 a barrel below the free-market price would provide an "equitable rate of return" on those investments. 43/ Ninety cents a barrel means a combined revenue loss for royalty and production tax of \$100,000,000

a year for the State when the main Prudhoe pool reaches full production. 44/

It should be pointed out that this is by no means the worst result that could be obtained through a discounted cash flow rate of return. Using the materials presented in Dr. Tanzer's study for the Alaska State Legislature, 45/ which excludes investments in TAPS from the base on which the rate of return is calculated, the field price would be below \$4.00 a barrel - less than half of the free-market price - if a rate of return of 15 percent before income tax were allowed as being fair. Dr. Arlon R. Tussing of the staff for the U.S. Senate Committee on Interior and Insular Affairs has repeatedly written that the total economic cost of producing North Slope crude and shipping it to West Coast refineries would be even less - around \$2.00 a barrel - and that the difference between economic cost and price represents "unearned bounty." 46/ Thus there is no dearth of support 47/ that could be cited by the President if he decided to suppress the price of North Slope oil below free-market levels in order to gain additional price incentives for other U.S. production. But the consequences for Alaska of that decision would be the loss of billions of dollars (see below).

3-C. Revenue implications. To provide an indication of the dollars-and-cents consequences of some of these oil-pricing

possibilities under present laws, computer projections have been made for the royalty and production tax revenues that the State would receive from Prudhoe Bay oil production if four of the possibilities were realized.

Case 1 is a free-market price case, 48/ providing a point of reference from which the consequences of the other three may be gauged. Case 2 represents a situation in which profit centers are shifted away from production operations as the result of a combination of corporate actions and federal price controls. 49/ A modified type of federal price controls - namely, establishing a ceiling price for oil at Valdez and holding it constant in nominal terms through time 50/ - underlies the forecast made in Case 3. 51/ The fourth case projects revenues under federal price ceilings based on the \$3.65 field price that is implicit under the assumptions of the "Tanzer report" if a "fair" pre-tax rate of return (discounted cash flow basis) of 15 percent is allowed. 52/

The following table shows the projected royalty revenues the State would receive under each of the four cases.

Alaska Royalty Income
from Prudhoe Bay Main Reservoir
(including income to be paid into Alaska Native Fund)
(\$ millions)

	<u>Case 1</u>	<u>Case 2</u>	<u>Case 3</u>	<u>Case 4</u>
FY 78	300.3	213.0	300.0	170.9
FY 79	482.2	304.0	461.1	267.0
FY 80	619.6	355.0	542.0	330.6
FY 81	704.8	359.0	548.0	354.3
FY 82	780.0	359.0	548.0	375.6
FY 83	900.0	359.0	579.0	398.1
FY 84	992.2	359.0	582.0	422.0
FY 85	1030.2	359.0	582.0	447.3

The next table shows the projected production tax revenues the State would receive under these four cases.

Alaska Production Tax Income
from Prudhoe Bay Main Reservoir
(reflects application of EDIC for reserves tax)
(\$ millions)

	<u>Case 1</u>	<u>Case 2</u>	<u>Case 3</u>	<u>Case 4</u>
FY 78	78.5	71.0*	78.5	71.0*
FY 79	127.0	114.5*	124.0	114.5*
FY 80	163.0	143.2*	147.1	143.2*
FY 81	247.9	152.3*	156.1*	152.3*
FY 82	398.2	303.5*	303.5*	303.5*
FY 83	467.3	336.1*	336.1*	336.1*
FY 84	510.1	359.6*	359.6*	359.6*
FY 85	551.2	375.1*	375.1*	375.1*

*Indicates payment made on cents-per-barrel basis. Case 3 differs in FY 81 from Cases 2 and 4 because its greater earlier tax rates used up the EDIC faster.

The next table combines the results of the first two and shows how much less income the State would receive under Cases 2,3, and 4 than it would receive under free-market conditions.

	Lost Income from Production Tax and Royalty (\$ millions)		
	<u>If Case 2 happens:</u>	<u>If Case 3 happens:</u>	<u>If Case 4 happens:</u>
FY 78	94.8	0.3	136.9
FY 79	190.7	24.1	227.7
FY 80	284.4	93.5	308.8
FY 81	441.4	248.6	446.1
FY 82	515.7	326.7	499.1
FY 83	672.2	452.2	633.1
FY 84	783.7	560.7	720.7
FY 85	897.3	680.3	809.0
TOTAL	3880.2	2386.4	3781.4

4. Gas problems. In contrast to the oil production tax, Alaska's single rate, percent-of-value tax on gas production is strikingly uncomplicated. Except for occasional rate changes - the last was in 1970 - it is essentially unchanged since its original enactment by the Territorial Legislature in 1955.

This simplicity does not mean the tax is free from actual and potential problems. It does have a similar type of adverse impact on the economics of production operations as the oil production tax, although its simplicity means that this impact is not aggravated, as it is with certain of the complicating features of the tax on oil production.

The chief difficulties in the present gas production tax concern the valuation of the gas for tax purposes. There are two sources for problems. One is the long-term contracts often encountered in gas sales which, while adopting a price that initially reflects the market value, may become increasingly unrepresentative of that value as time passes during the term of the contract and market conditions change. The second source of problems for the State is price regulation by the Federal Power Commission (FPC).

Historically the market for gas production has been very different from that for oil. Often the gas purchaser is not affiliated with the gas producer, but instead is a pipeline company devoted primarily to the business of obtaining long-term commitments of gas supplies for its pipelines and shipping that gas from the field to the markets served by its pipeline system. ^{53/} For such a company to build its pipelines, it must have gas supplies committed for shipment through those lines for a time long enough to allow the investment to be recouped and a profit earned. (The tariffs charged and the profits earned are regulated by the FPC for interstate pipelines, and intrastate lines are generally regulated by those states.)

Gas sales contracts therefore tend to involve large, long-term commitments. It is not unusual to find them running for fifteen to twenty years or even longer. This

practice is reflected in Alaska. Contracts for gas in the Cook Inlet area run twenty years and longer, and long-term sales are also being discussed for gas from Prudhoe Bay.

In making a long-term sale, the producer and the buyer each make separate estimates of what the gas will be worth to him in the future. The producer must make a judgment about the price he might get for the gas 10 or 15 years later if it were not committed to his prospective purchaser; against that consideration he must balance the benefits of selling the gas now instead of finding another purchaser. Conversely, the buyer must assess the costs of the present contract against the possible costs if he must buy other gas at a later time. The negotiated price represents a compromise between the expectations of the two parties.

As the contract runs, conditions change. Newer contracts will reflect these changes, but the older agreements, and the expectations they incorporate, remain fixed. If the market price rises above the price provided in the older contract, the difference between the contract price and the market price represents a bargain to the purchaser. The benefits of this bargain increase the value of his contract right. For example, if the buyer has a contract right to buy 100,000 Mcf of gas at 24 cents an Mcf during the next year and the market price has gone to 45 cents an Mcf, the buyer will obtain \$45,000 worth of gas at a cost of only

\$24,000. The \$21,000 difference represents the value to him of his contract right to buy that gas at 24 cents an Mcf. The market value of the gas remains 45 cents an Mcf, however.

One interesting problem, which arises from a series of long-term contracts for gas production of a field, is the multiple pricing of gas production. Depending on which contract the gas is being produced for, it may have any of several different prices. In the Cook Inlet area, prices for gas from the Kenai gas field range from 17 cents an Mcf to approximately 45 cents. Other gas from the Inlet that is going to the same market as some of the Kenai field's gas is reported at over 60 cents.

While there may be a multiplicity of prices under the various contracts, there is theoretically only one market value at any given time. Theory in this case, it seems, may be controlling for production taxes, since the tax statute makes a distinction between price and value.

If oil or gas is sold under circumstances where the sale price does not represent the prevailing value...the department may require that the tax to be paid upon the basis of the value...

AS 43.55.020(f). The question of how the prevailing value should be determined is addressed in proposed draft regu-

lations of the Department of Revenue, which should be released for public examination and comment about the same time as this report. Public hearings on those proposed regulations will then be announced, probably for early March.

Compared to the gas resources at Prudhoe Bay, this problem in the production tax for Cook Inlet is insignificant. The estimated 27,000,000,000,000 cubic feet of gas reserves there represent an energy resource equivalent to approximately 4.5 billion barrels of oil. This roughly equals half the energy contained in the oil reserves of that field, and it represents an energy resource far larger than that contained in the remaining recoverable oil reserves of any other field in the United States. 54/ It has over 10 times the energy remaining in all the Cook Inlet oil reserves put together. 55/

The taxation of the enormous non-renewable gas resource of Prudhoe Bay therefore should merit similar care and attention as that given to the oil reserves there. In this regard, one may look at the present production tax rate of eight percent that will be imposed on most of the oil production and ask why the gas tax rate is only half that.

Because gas production from Prudhoe Bay will be a major source of revenue for the State of Alaska during the middle and late 1980's, it is prudent to protect those revenues from the effects of federal price controls, which

cannot be expected to be always administered for Alaska best revenue interests. The FPC has responsibility for regulating natural gas prices for interstate commerce. As with the oil pricing question, the FPC will have no difficulty finding published opinions to support an extremely low, or even negative, value for the gas in the field. 56/ A tax based on value, as the present gas production tax is, accordingly will not protect Alaska's revenues against such pricing actions by the FPC.

C. PROPERTY TAX PROBLEMS

As explained in Chapter II, the State property tax on oil and gas equipment and facilities is really joint taxation by the State and the municipality (if any) in which the taxable property is located. The State, through the Department of Revenue, determines the assessed value of the property for the municipal property tax as well as for the State's tax. The municipality for its part is free to levy whatever millage it wants, subject to certain conditions already described in Chapter II.

In the three years of this tax, this arrangement has generally worked quite well. However, there are four areas in which the tax could be improved: the omission of certain important kinds of oil and gas related properties from the definition of taxable property; present uncertainty about how pipelines should be valued; the static nature of the \$1500 per-capita limitation of municipal taxation; and the extent to which credits against the State tax should be allowed for municipal property tax payments.

1. Omission from taxable property. The tax falls only on property used or committed for use in exploration operations, production operations or certain pipeline transportation operations. This limited range of the tax means that several major kinds of oil and gas related properties are not assessed

by the State, although they may still be subject to local property taxes if they lie within a municipality. These properties include such costly investments as oil refineries, gas processing plants, LNG facilities and petrochemical operations.

It may be said that these properties should be excluded from the State property tax as an incentive to would-be investors to locate their projects in Alaska. This contention overlooks two significant considerations that will be borne in mind by any prudent investor.

First, the incentive may not be all it seems to be. The exclusion of these types of property from the State's property tax does not mean that they are excluded from property tax levied by a municipality. A municipality may levy at rates up to 30 mills 63/ and even beyond that in certain circumstances. 64/ Since municipal property taxes are creditable against the State tax, excluding these properties from the State tax offers an incentive only when the municipal levy is less than 20 mills, and then the amount of that incentive is only the difference between the State and municipal millage rates. In fact, where the municipality levies at a rate above 20 mills, the exclusion from State property tax can act as a disincentive since the tax paid to the municipality is creditable against the State tax on taxable property not only within the municipality but

outside it as well. 65/ In other words the municipal levy in excess of 20 mills would be creditable against State tax on the taxpayer's property located elsewhere, thus holding the taxpayer's overall property tax rate at 20 mills statewide.

The second consideration of a would-be investor considering Alaska as a place to locate is that taxing jurisdictions not infrequently recognize that once a major investment of this kind is made, it is difficult to re-locate. Then the taxing authority need not hold out the enticement of tax exemptions any longer, especially when the exemption takes the form of a simple omission or exclusion from the definition of taxable property. The prudent investor should, therefore, look at the property tax rates on other, similar kinds of property and assume that his investment will be similarly taxed. This is exactly what El Paso has done in its filings with the Federal Power Commission regarding its proposal for transporting Prudhoe Bay gas. Even though LNG facilities are not currently taxed under the State property tax (and the proposed site at Gravina Point is not within a municipality with taxing powers), El Paso's cost projections include a 20 mill property tax on its LNG plant. 66/

After an investor has assumed he would pay property taxes and in fact no property taxes are imposed on his property, he gains an unforeseen windfall. This point is seldom lost on the taxing authority, which makes it all the

more likely that an investor will plan on property taxes being among the costs of his investment.

There is, therefore, no sound basis to support the notion that the present exclusions or omissions of the present property tax law need to be continued as an incentive for investments in Alaska. Without the incentive-based argument, no sound reason exists for continuing to exempt these kinds of oil and gas related properties from the State's property tax.

On the other hand, there is good reason to include those properties in the State's tax. For one thing, the property tax will be uniformly administered for these properties throughout the state, instead of allowing the taxpayers to play municipal assessors against one another by using a decision of one to under cut the position of another. And there would be additional income for the State from the properties already located in Alaska.

2. How to value pipelines. Under AS 43.56.060(e), pipelines may be valued on any of four different bases, depending on the circumstances. While a pipeline is being built, it is valued on the basis of actual costs incurred or accrued, but with no depreciation. 67/ After it begins operating, it is assessed "with due regard to the economic value of the property based on the estimated life of the

proven reserves ... then technically, economically and legally deliverable" to it, unless the "economic life" of those reserves is "materially shorter than the estimated physical life" of the pipeline. 68/ In the latter case, the operating pipeline is valued on the basis of actual costs with straight-line depreciation over its economic life (elapsed life 'since operations' began, plus the estimated remaining life of the deliverable reserves). If, for some reason beyond the pipeline owners' control, the pipeline cannot be used (or, during construction the construction is substantially or completely stopped) for at least 90 consecutive days during the year, then the pipeline's assessed value is to be "adjusted to take into account any diminution in value." 69/

The problem encountered in the administration of the tax has not been with the first or fourth cases, but with the valuation of pipelines operating normally. There seems to be some uncertainty as to when the economic life of the deliverable proven reserves is materially shorter than the "estimated physical life" of the pipeline, and no less than three different interpretations have been given so far to this condition. Some taxpayers have contended in their appeals to the Assessment Review Board that, with proper maintenance, their pipelines could last for 75, 100 or even 200 years and more and that this is the measure of the pipeline's physical life. Not surprisingly, this would

almost always cause their pipelines to be valued on the actual-cost-less-depreciation basis, which is lower than the assessment made with due regard to the economic value of their pipelines.

In administering the tax, the Department of Revenue disagrees with the taxpayers' interpretation of the words "estimated physical life." Instead, the Department regards that phrase as meaning the originally estimated life of the pipeline based upon the pipeline owners' expectations as to the economic life of the deliverable reserves when they began to build that pipeline. If the present estimate of the economic life of the deliverable reserves is materially shorter than the owners' original expectations, then in the Department's view the exception applies and the pipeline is to be assessed on the basis of its actual cost with depreciation. Otherwise, it is valued with due regard to its economic value.

The Assessment Review Board places still another interpretation on this phrase. To the Board, "estimated physical life" means the remaining economic life of the deliverable reserves, during which time the pipeline will be maintained, plus an additional time (such as three years) after the pipeline stops operating and maintenance ceases, during which the pipeline deteriorates to a point where it would no longer be capable of transporting oil (or gas, as the case may be).

Under the Board's reading, every pipeline will eventually qualify for the exception when the remaining economic life of the deliverable reserves becomes short.

With such divergent views as to the meaning of the statute, there is substantial uncertainty about which approach will be used to value pipelines generally and the Trans-Alaska Pipeline in particular. This uncertainty is a deficiency which should be corrected to assure a probable result for both the State and the taxpayers owning the largest asset taxable under the property tax. The value of TAPS will be too great to allow this uncertainty to be tolerated. Only one valuation method for pipelines operating normally should be allowed.

The valuation method chosen should be one which clearly reflects the full and true value of the pipeline property.

In the Department's view the use of the actual cost depreciated method does not accurately reflect the full and true value of the pipeline property. This method takes the actual costs incurred and depreciates them over the life of the proven reserves of oil or gas that are deliverable to the pipeline. The value of the property reaches its peak in the last year of construction and decreases ever after. While this method takes into account the reduction in value of the pipeline property over time it does not take into

account the increase in value as the result of inflation. Accordingly, some other method that takes inflation into account as well as depreciation, more accurately measures the value of these income producing assets. The value of a pipeline is not reflected solely by its historic cost and its declining reserves, but also by the current prices at which a replacement property would have to be purchased.

The difference between a method that takes into account appreciation as well as depreciation and one that accounts for depreciation only is displayed in the following table. This table shows the property valuations of the Trans-Alaska Pipeline under the two approaches for years 1978 - 1985, using a hypothetical life of 30 years for depreciation.

(Millions of Dollars)

	Actual Cost		Replacement Cost (trended-10% yr)	
	(Less Depreciation - 30 yrs)		(Less Depreciation - 30 yrs)	
	Value	Tax	Value	Tax
1978	5,500	110.0	5,500	110.0
1979	5,317	106.3	5,848	117.0
1980	5,139	102.8	6,219	124.4
1981	4,968	99.4	6,613	132.3
1982	4,803	96.1	7,031	140.6
1983	4,642	92.8	7,477	149.5
1984	4,488	89.8	7,950	159.0
1985	4,338	86.8	8,454	169.1

As shown in the table a replacement cost method (appreciated approach) produces a valuation which is almost double the actual depreciated method by the year 1985. In view of the

uncertainties of valuation and a potential depressed valuation a change in the pipeline valuation method would appear warranted.

3. Municipal Limitations. As explained in Chapter II, the State's property tax provides more than just a revenue measure for the state. It sets an interface with municipal taxation by providing a credit against the property tax for property taxes paid to municipalities, and sets limitations on the amount of tax that may be imposed by the municipalities. Two problems are exhibited: one in the municipal limitations themselves, and the other in amount of credit which may be taken against the State's tax.

3-A. Static municipal limitations. The two municipal limitations set out in the statute are optional, and each year a municipality must choose the method or limitation which it will use. 70/

One limitation is a limitation on the municipality's total assessed value. A municipality may not levy a tax on the value of that portion of oil and gas properties assessed by the Department of Revenue which, when combined with the value of other property taxable by the municipality, exceeds 225 per cent of the average per capita assessed full and true value of property in the state multiplied by the number

of residents in the state. 71/ No municipality has yet elected this limitation.

The other is a limitation on the total taxes received by the municipality. 72/ Originally a municipality could not levy at a rate that would yield an amount of revenue from the total municipal property taxes that exceeded \$1000 times the number of residents in the municipality. In 1976 the Legislature raised the per-capita amount to \$1500. 73/

The shortcoming of the \$1500 per-capita limitation is that it is unchanging through time, even though inflation continues. As conditions change, this ceiling could be indexed to reflect those changes. A static ceiling may become unduly hard for a municipality faced with the task of maintaining or augmenting its services to its residents.

3-B. Municipal credit. In addition to the problem discussed above regarding the municipal limitations themselves, there is also a problem with the credit against the State's tax for property taxes paid to a municipality for the same property.

Under AS 43.56.010(d), a tax paid to a municipality under AS 29.53.045 may be credited against the state property tax. By regulation the Department of Revenue has interpreted this as meaning that taxes paid to municipalities on oil and

gas properties are creditable against the State tax up to the limitations of AS 29.53.045. Property tax levied under AS 29.53.055 by a municipality in excess of the limitations of AS 29.53.045 is not creditable against the State tax under regulations of the Department. 74/ For example, if a municipality makes a special levy under AS 29.53.055 for the purpose of pledging, paying or securing the payment of principal and interest on bonds, then the limitations of AS 29.53.055 and AS 29.53.050 do not apply to that levy. The total taxes levied by the municipality would exceed the two ceiling limitations discussed above for oil and gas properties. The taxes in excess of the limitations that are paid to the municipality are not creditable against the State's tax under the regulation.

If the taxes imposed in excess of the limitations were allowed to be credited against the State tax, it would mean an unnecessary reduction in State revenues. It would also lead to unequal treatment among taxpayers, giving preferential treatment to the large oil companies. For example, if a municipality levies a tax under AS 29.53.055 in excess of the ordinary limitations, all taxpayers will have to pay that special levy to the municipality for those debts. Taxpayers, however, who have oil and gas property assessed by the Department of Revenue would (in the absence of the Department's regulation) be able to credit their payments of the special levy against the State's tax, thereby paying

less overall tax than taxpayers who have non-oil and gas properties. 75/

The regulation is currently being challenged in the courts. 76/

D. RESERVES TAX PROBLEMS

The reserves tax has so far proved to be a highly successful, temporary addition to Alaska's oil and gas tax structure. Despite its success, the present reserves tax has several flaws which, although they so far have not caused problems, could lead to great difficulties if the tax were ever made permanent.

The first of these is the assessment of reserves before they are brought into production. Because large oil and gas properties are not bought and sold very often, the assessment of a property with proven reserves is a very detailed and difficult matter even when the property has a production history to rely upon. Individual well productivity, gas-oil ratios, water cuts and many other data from actual production are all analyzed to evaluate how the reservoir is performing and how it will perform in the future. Technical engineering expertise is required to project what efforts (and when) will be needed to assure maximum recovery, and the costs of those efforts must also be estimated. Economic advice, too, is needed to project not only gross revenues, but also to estimate when the economic conditions will develop that will terminate production operations. All this and more must be done to determine a year-by-year forecast of net proceeds from the reserves, which are then discounted to their present value in assessing those reserves.

This complex and arduous task is made even more so when there is no production data to rely upon. Increasingly, technical opinion (allbeit the very finest available) must substitute for actual production data.

The second drawback to the present tax is that the millage is set before the assessment is known. Worse, the assessing agency must submit revenue projections for the reserves tax after the millage is known but before the assessment is made. Ordinarily, other taxing jurisdictions set their levy after the assessments are known and the millage then produces the desired amount of revenue. The valuation of assessable properties is done fairly and impartially, as it must be, even when the millage has already been set. Accordingly, if the total assessed value proved to be higher or lower than estimated, the pre-set millage would have to be corrected to produce the desired tax revenue. The general practice of setting the millage after the assessments are known is simpler, since the millage is set more than once.

Chapter V - Footnotes

- 1/ Milton Lipton, Testimony at the Joint Hearings on Proposed Oil and Gas Legislation before the House and Senate Resources Committees, Tuesday, March 23, 1973; Transcripts, p. 7.
- 2/ Jerome Zeifman formerly served as Chief Counsel to the Committee on the Judiciary of the U.S. House of Representatives, as well as Chief Counsel to the Special Subcommittee on State Taxation of Interstate Commerce.
- 3/ Kenneth Ainsworth was formerly an economist on the staff of the Special Subcommittee on State Taxation of Interstate Commerce. He has also served as a consultant in the revisions of the tax systems of New York City, the State of Connecticut and the District of Columbia.
- 4/ State Taxation of Interstate Commerce, U.S. House of Representatives Special Subcommittee on State Taxation of Interstate Commerce of the Committee on the Judiciary - June 15, 1964.
- 5/ Jerome M. Zeifman and Kenneth G. Ainsworth, The Taxation of the Petroleum Industry Under Alaska's Corporate Income Tax. January 1977.
- 6/ "Fifth Annual Corporate Tax Study," Congressional Record, Vol. 122, No. 151 - Part III.
- 7/ Zeifman and Ainsworth, op. cit., pp. 10-12.
- 8/ Ibid., p. 12.
- 9/ Fifth Annual Corporate Tax Study, Congressional Record, Vol. 122, No. 151 - Part III.
- 10/ In recognition of this conflict the Alaska Legislature repealed the applicability of the DISC exemption for Alaska income tax purposes. Sec. 3, ch. 153, SLA 1975.
- 11/ Zeifman and Ainsworth, op. cit., p. 13.
- 12/ AS 43.20.036(a).
- 13/ AS 43.20.036(b).
- 14/ AS 43.20.036.
- 15/ AS 43.20.021.

- 16/ AS 43.19.010, Article IV.
- 17/ Zeifman and Ainsworth, op. cit., p. 3.
- 18/ Ultimately the corporate decision-making turns on a subjective interpretation of the technical analyses, with greater or less weight being given to the positive points or the negative ones. At this point, a negative attitude induced by what the decision-maker perceives as a harsh or unfair tax climate can color the entire decision and dampen enthusiasm in the bidding. Conversely optimism, bolstered by encouraging speculation about a structure with large potential, can drive the bidding to great heights, as witness the 1969 oil and gas lease sale.
- 19/ There is a third category, "stripper well oil," for production from wells at less than 10 barrels a day. It is unimportant to Alaska, although there are thousands of stripper wells Outside. The federal controls of crude oil prices are more fully discussed later in this chapter.
- 20/ These policies were presented to representatives of the Department of Revenue by Gorman Smith, Assistant Administrator of the FFA, and Edwin P. Mampe, FEA's director of price regulation.
- 21/ Periodic well testing does provide a sort of base line against which a particular test may be compared to obtain, in a gross sense, some feeling for its reasonableness. A well test that suddenly and greatly diverges from the results of previous tests may reflect some breakdown of the test rather than a sudden change in the condition of the well, unless its results are confirmed by further testing. But the "feel" acquired from a history of well tests hardly approaches the degree of accuracy needed for the detailed tax calculations that are based on those well tests, and an audit of those calculations cannot be satisfactorily conducted in reliance on that "feel."
- 22/ The inability to conduct complete audits of the production tax has been a concern of the Audit Division of the Legislative Budget and Audit Committee, as well as the Department of Revenue.
- 23/ The term "field price" is used in place of the commonly used phrase "wellhead price" to avoid the misleading connotations of the latter expression. In a field with high production volumes and a simple pattern of land ownership, as is often found in Alaska, operations for separating the oil, water and associated gas and

for reducing basic sediments, salts and water to acceptable levels are more economically conducted at one or more central facilities than at separate, small installations at each wellsite, as is done in many fields in the Lower 48. Thus, where the "wellhead" facilities are replaced by larger, more efficient ones at a central location, the price of the production that corresponds to the price at the "wellhead" facilities is the price at the central facilities. The term "wellhead price" carries over from areas where lower production rates or more complex patterns of land ownership led to on-site facilities for each well. In a field with centralized facilities, therefore, "wellhead price" should be understood to mean the price at those facilities, reflecting the fact that the field production operations have been centralized. However, it still suggests the individual wellheads. "Field price" avoids this suggestion and the misunderstanding that may result from the other term.

- 24/ AS 42.06.150.
- 25/ Prudhoe Bay oil is expected to be 27° API gravity, for which the latest cents-per-barrel rates are \$0.3051, \$0.3662 and \$0.4883. If the field price is \$6.10, 5% of it is \$0.3050, 6% is \$0.3660 and 8% is \$0.7880 - which are \$0.0001, \$0.0002 and \$0.0003, respectively, below the cents-per-barrel rates. Thus, at a \$6.10 field price for Prudhoe oil, the cents-per-barrel tax would have just begun to take over as the basis for production tax payments.
- 26/ Energy Policy and Conservation Act of 1975, Public Law 94-163, Title IV, sec. 401(a); codified in pertinent part as 15 U.S.C. sec. 757. The provisions relating to the time and nature of the report are in 15 U.S.C. sec. 757(g) (1)-(3).
- 27/ 15 U.S.C. sec. 757(g) (3); 42 U.S.C. sec. 6421.
- 28/ The changes in price controls under Public Law 94-163 took effect midnight December 15, 1975.
- 29/ Production in the Cook Inlet area was frozen at a lower price than \$5.25. Even today, after FEA has allowed some price increases since February 1976 for "old oil" and has given some extra relief for California and Alaska crudes by closing the price differential from 5 cents to three for each degree of API gravity below 40°, the ceiling price for over half of the Inlet's production corresponds to a value \$4.855 for 34° crude.
- 30/ 15 U.S.C. sec. 757(a).

- 31/ It was believed then that 60% of U.S. oil production was "old oil" as of February 1, 1976 and that the average "old oil" price then was \$5.25. On this assumption, an average price of \$11.28 for the "upper tier" yields the prescribed \$7.66 average price for both tiers.
- 32/ Originally the annual rate of increase was the sum of the percentage increase of the GNP deflator and a 3% incentive, with the sum limited to 10 percent. This was changed to the simpler 10% yearly rate by the Energy Conservation and Production Act, Public Law 94-385, sec. 122(1), effective August 14, 1976 and codified as 15 U.S.C. sec. 757(d)(1).
- 33/ Public Law 94-385.
- 34/ 15 U.S.C. sec. 757(j)(1).
- 35/ 15 U.S.C. sec. 757(i)(1). Stripper-well crude is oil "from a property whose maximum average daily production of crude oil per well during any consecutive 12-month qualifying period after December 31, 1972, does not exceed 10 barrels." 15 U.S.C. sec. 757(i)(2).
- 36/ 15 U.S.C. sec. 757(c)(2).
- 37/ The President is to report to Congress February 15, 1977 on the effects of decontrolling "stripper-well" oil. On March 15, 1977, he may submit proposals to change any part of the whole structure, which will take effect unless rejected by either House. 15 U.S.C. sec. 757(f).
- 38/ 15 U.S.C. sec. 757(g)(2). When enacted, this reference to the "highest actual weighted average first sale price" was probably to "new oil" prices. However, with the enactment of the Energy Conservation and Production Act in August 1976, the "stripper-well" classification was established, and the actual "first sale" price for this classification is decontrolled.
- 39/ 15 U.S.C. sec. 757(g)(1) and (2).
- 40/ A tabulation and explanation of how the market would set the field price for Prudhoe Bay oil are given in Chapter IV.
- 41/ The President has not indicated he would, but he certainly could, establish a special price ceiling for North Slope oil and still include that oil on the teeter-totter. 15 U.S.C. sec. 757(b)(1) states that the pricing regulation "may...provide for different ceiling prices (or manner of determining ceiling prices) for different classifications of crude oil...." The only limit to the President's

reclassifying power are that any reclassification be "administratively feasible" and that it be "consistent with obtaining optimum production of crude oil in the United States." 15 U.S.C. sec. 757(b)(1)(A) and (B). Neither of these would prevent the President from first creating a third pricing tier especially for North Slope oil with a controlled price less than market value yet still allowing a "fair" rate of return, and then including that tier with the rest of U.S. production on the teeter-totter.

- 42/ Mortada International, The Determination of Equitable Pricing Levels for North Slope Alaskan Crude Oil (November 1976).
- 43/ "A price at Valdez falling between 11.50 and 12.40 \$/B [in 1976 dollars] provides an equitable rate of return to the owners of Prudhoe Bay Field and TAPS... Under present tariff expectations, a well head price between 7.00 and 7.90 \$/B in 1976 dollars, to be adjusted quarterly for inflation, would be equivalent to a Valdez price of 11.50 to 12.40 \$/B." Mortada International, op. cit., pp. VII-6 to VII-7. Elsewhere that study concludes that North Slope oil is, from a refiner's standpoint, comparable in value to Saudi Arabian Light crude (pp. ii-11 to II-17), and that the market price at Valdez, corresponding to the cost to a West Coast refiner for Saudi Arabian Light, is \$12.40 (p. III-12).
- 44/ Assuming production of 1,600,000 barrels a day and an effective production tax rate of 7.5%.
- 45/ Tanzer Economic Associates, Inc., Alaska's Prudhoe Bay Oil: Profitability and Taxation Potential (January 9, 1976).
- 46/ Crude oil from Alaska's Prudhoe Bay field will be laid into the West Coast of the United States at an economic cost of around \$2. I believe that we can expect that field to be joined very soon by other very large (and consequently very low cost) reservoirs in Northern Alaska.

Arlon R. Tussing, "The Price of Petroleum," The Conference Board Record XI (September 1974), pp. 12-14.

Because a large proportion of total supply will be produced at a cost substantially lower than the prevailing price, the energy industries will continue to generate vast unearned profits (differential rents) for those who control resources that can be developed at low cost....This unearned bounty - the difference between cost and price on an ever-growing volume of production - will total tens of thousands of millions of dollars [worldwide] each year.

Arlon R. Tussing, "Three Classes of Energy Resources," Energy Policy (September 1974), pp. 174 et seq. As far as Dr. Tussing is concerned, any price for North Slope oil over \$2 a barrel would represent more than a positive price incentive for North Slope development, although he would allow the price to rise above \$2 a barrel to a price equal to the highest economic cost for an energy supply needed to meet U.S. energy demand. See, e.g., Arlon R. Tussing, "New Priorities for Energy and the Environment," The Northern Engineer, VI (1974), pp. 6-7; "Three Classes of Energy Resources," loc. cit.

47/ Inadvertently the Alaska State Legislature has exposed itself to citation in support of artificially suppressed North Slope oil prices because of the publicity in the Wall Street Journal and elsewhere regarding its consideration in the last Session of "excess value" taxes. A Bill to tax the "excess profits" to be realized by free-market prices for Prudhoe Bay oil is predicated on a determination that the free-market price will be unjustifiably high.

48/ The assumptions underlying the development of the free-market price projections were explained and tabulated in detail in Chapter IV.

49/ This case represents a combination of federal pricing decisions and corporate ability to adapt to the opportunities presented by those decisions. In it, the TAPS owners begin operations and file tariffs with the ICC using calendar years as their accounting basis. Throughput for the year is low because it is zero until mid-year and reaches 1.2 million barrels a day only when it is very late in the year. This sets the tariff initially at a very high level, allowing ICC to make a show of lowering the tariff to satisfy public opinion while leaving it still high enough to allow most or all of this total TAPS costs in the rate base.

FEA, in making its pricing decision, not only uses the initial tariff filed for TAPS to net back to Prudhoe Bay from the market, but it also points to the West Coast surplus, states that it is the surplus oil which determines the economic value of the rest of the oil, and then says the Gulf of Mexico is where the surplus will go. Gulf of Mexico prices for imported crude oil are not much higher than for the West Coast, so in effect nearly all of the extra costs of getting the surplus oil to the Gulf coast would represent a reduction in the field price for Prudhoe Bay.

Putting numbers to these assumptions yields the following for the initial pricing of North Slope oil:

Price of Saudi Arabian crude (31°), FOB Ras Tanura	\$11.56
Tanker tariff to U.S. Gulf of Mexico coast	<u>1.83</u>
Cost to Gulf Coast refiner	\$13.39
Tanker tariff: Valdez to Gulf Coast via Panama Canal	<u>2.25</u>
"Netback" price at Valdez	\$11.14
TAPS initial tariff	<u>5.92</u>
"Netback" price at Prudhoe	\$ 5.22

In running the model, the Prudhoe "netback" price was rounded to \$5.25.

As one final assumption: FEA determines that this is not only the market price, but is also a "fair" or "just" price on the basis of discounted cash flow rate of return analysis for the field development investment only (TAPS investment excluded). It then holds the price at \$5.25.

As FEA has already decontrolled all major refined products except gasoline (and gasoline prices nationwide are not now at the ceiling), there is "play in the joints" to allow the integrated companies to assign the profits to downstream operations.

Prudhoe Bay production is assumed to be unchanged.

- 50/ This was a recommendation of the "equitable pricing" study done for FEA (Mortada International, op. cit., pp. viii, VII-6), except that it suggested holding the price constant in real terms (i.e., allowing it to rise through time just enough to offset the effects of inflation.
- 51/ In this case, FEA regulates the price at Prudhoe Bay by controlling the price at Valdez. This simplifies its problems arising from possibly more than one TAPS tariff. It was recommended by the "Mortada report."
- 52/ This case is a kind of middle ground between the \$5.25 price of Case 1 and Dr. Tussing's declarations about a \$2-a-barrel laid-in cost at the West Coast for North Slope oil. It uses a \$3.65 price, which is the price that would yield a 15% rate of return under Dr. Tanzer's model. Production rates are the same as for the other three cases.

- 53/ Because gas supplies in the United States have dwindled at an alarming rate, some pipeline companies have been joining exploratory ventures in hopes of discovering for themselves secure supplies of gas in the future.
- 54/ There are 13 fields in the United States whose remaining proved recoverable oil reserves, plus cumulative production, total 1,000,000,000 barrels or more. Of these only four had remaining reserves in excess of a billion barrels at the beginning of 1976: Prudhoe Bay field, Alaska (9.6 billion); East Texas field, Texas (1.69 billion); Elk Hills field, California (1.05 billion); and the Santa Ynez Unit, California (1.0 billion). The Yates field in Texas had 0.98 billion. Source: "Here are the Big U.S. Reserves," Oil & Gas Journal (January 26, 1976), pp. 118-120. One cubic foot of gas contains about 1000 British thermal units (Btu), while a barrel of oil contains somewhat less than 6,000,000 Btu. The Prudhoe Bay gas thus represents some 27 quadrillion (27,000,000,000,000,000) Btu, while the East Texas field - largest U.S. oil field after Prudhoe Bay - has 10 quadrillion Btu represented by its remaining reserves.
- 55/ In the survey cited in the preceding footnote, fields in the Cook Inlet area were reported to have a total of 407,600,000 barrels of remaining reserves, exclusive of the Trading Bay and Beaver Creek fields. These do not have enough remaining reserves to push the total to the 450 million barrels of oil that would represent one-tenth of the energy content of the Prudhoe Bay gas.
- 56/ ...the range of practical discretion available to the [Federal Power] Commission in setting of a wellhead price may be slim or nil. It is by no means obvious that the array of prices at which the entire gas production of the Prudhoe Bay field could be sold would cover a cost of service transportation tariff, and leave anything at all for a wellhead price. That is, the netback value in the field of North Slope gas delivered to the Lower 48 may well be zero or negative!

Arlon R. Tussing, Analysis of Transportation Proposals for North Slope Natural Gas (Report to State of Alaska, Office of the Attorney General - March 31, 1975 draft), pp. 33-34 (original emphasis). Relying heavily on this analysis, Governor Hammond testified on February 2, 1976 before the Federal Power Commission about his concern that the value of the gas in the field may be "very small indeed." Subsequently Dr. Tussing made a subtle qualification of his original position:

While it is still accurate to say that the wellhead value of the gas, squeezed between the market price and very high transportation costs, may be "very low indeed," it no longer appears likely that the wellhead price could fall below about 50 cents per thousand cubic feet, if any gas is sold for interstate shipment.... The crucial new information [that "became available after I made my original report"] concerns the additional cost of producing gas for sale.... Unless the operating companies receive a high enough price for gas at the wellhead to offset these costs, together with any operating costs associated with preparation of the gas for pipeline transportation, it would not be rational for them to make the investments necessary to make the gas available for sale.... There is still a danger that transportation costs will be so high that the "netback" value of the gas will be low (less than 50 cents), zero or even negative. Indeed, that danger seems even greater now than it did at the time I wrote the report to the task force.

Arlon R. Tussing, "Qualification of Analysis Regarding Wellhead Price of North Slope Natural Gas" (Memo to Attorney General Avrum Gross - February 27, 1976).

- 57/ AS 29.53.050(a).
- 58/ AS 29.53.055(a).
- 59/ AS 43.56.010(d); 11 AAC 05.840.
- 60/ El Paso Alaska Company, Trans-Alaska Gas Project Socio Economic Analysis (August 1975) p. 17.
- 61/ AS 43.56.060(e)(1). While construction is ongoing, costs incurred solely for construction facilities (as opposed to permanent facilities of the pipeline itself or comprising part of an overall, integrated pipeline system) are factored increasingly into the assessed value as construction progresses toward completion. 11 AAC 05.890(b)(1).
- 62/ AS 43.56.060(e)(2).
- 63/ AS 43.56.060(e)(3).
- 64/ AS 29.53.045 and AS 29.53.050.
- 65/ AS 29.53.045(c).
- 66/ AS 29.53.045(b).
- 67/ Sec. 8, ch. 107, SLA 1976.

68/ 15 AAC 05.840.

69/ A similar problem exists when a municipal levy exceeds 20 mills. The taxpayer is then able to offset the tax in excess of 20 mills against the State tax paid on property located elsewhere in the state.

70/ SOHIO Pipe Line Co. et. al., v. North Slope Borough and the State of Alaska, Superior Court 76-5027.

CHAPTER VI. RECOMMENDATIONS

A. RECOMMENDATIONS FOR THE CORPORATE INCOME TAX

As discussed in Chapter V, the corporate income tax has two deficiencies: (1) the use of the eroded federal income tax base, with its incentives that are unrelated, inappropriate or sometimes even hostile to the policies and objectives of the State, and (2) the use of the destination-oriented sales factor, which does not truly reflect oil and gas production activity in the State.

The Federal Eroded Tax Base. To solve the problem of the federal eroded tax base the Department of Revenue recommends the Zeifman and Ainsworth proposal for substituting a new tax base measured by "book income." Specifically, a franchise tax should be imposed on corporations of a certain size that are engaged in the production, transportation and/or refining of oil or gas in Alaska. This new tax would be in lieu of the corporate income tax and would be measured by the net income, before deduction of income taxes, of a corporation as reported and independently certified to its stockholders (book income). In addition to the basic "book income" base, the State should adopt its own special tax incentives specifically tailored to Alaska policies and goals. This would solve the problem of the eroded tax base by eliminating all present and future federal tax incentives, subsidies and accounting devices developed specifically in response to the federal tax law. The erosions are eliminated since a corporation's

book income is determined by normal rules of accounting independently and without reference to federal tax law.

Although there would be some flexibility in determining net income from corporation to corporation based upon different accounting rules and methods, there are real deterrents against manipulating "book income" for state tax purposes. "Book income" is subject to certification under rules promulgated by the American Institute of Certified Public Accountants and is subject to review by the Securities and Exchange Commission. In addition, since a corporation's first allegiance is to its stockholders, it is improbable that manipulations would be made in the computation of "book income" to lower the Alaska tax liability at the expense of the corporation's stockholders. In addition, the demands of creditors and corporate bond holders would also be a constraining force on any attempt to lower a corporation's book income for state tax advantages.

The effectiveness of eliminating the federal erosions by switching to a franchise tax measured by "book income" is shown in the Zeifman and Ainsworth Report. They found in the sample of large oil corporations doing business in Alaska that book incomes exceeded federal taxable incomes by 1.6 to 3 billion dollars a year over the last three years.

The specific difference between book income and federal

taxable income is shown in a table from the Zeifman and Ainsworth Report:

DIFFERENCE BETWEEN BOOK INCOME AND TAXABLE INCOME
FOR A SAMPLE OF OIL COMPANIES OPERATING IN ALASKA

<u>Company</u>	<u>Difference 1973 (thousands \$'s)</u>	<u>Difference 1974 (thousands \$'s)</u>	<u>Difference 1975 (thousands \$'s)</u>
A	NA	221,219	38,825
B	177,629	208,882	129,451
C	NA	NA	17,009
D	39,814	34,204	NA
E	166,769	242,587	150,231
F	193,072	368,175	110,248
G	NA	NA	464,781
H	335,080	448,695	608,333
I	84,495	93,351	NA
J	(61)	(333)	72
K	NA	46,338	(120,374)
L	261,888	280,454	NA
M	278,634	784,519	193,439
Total	1,834,298 (4 cases not available)	3,056,434 (2 cases not available)	1,592,015 (3 cases not available)

In addition to eliminating the federal erosions, the use of "book income" also eliminates conflicting and non-responsive federal tax incentives. Since the State begins with a clean slate (book income), the Alaska Legislature is free to establish its own taxation policies consistent with Alaska's specific interests and objectives, instead of contending with federal tax policies that are now being incorporated into the State's tax.

The Department does not recommend one other possible solution - adding back to federal taxable income all non-

desired erosions (federal tax incentives, subsidies and other tax accounting devices) which conflict with Alaska policies. Although this alternative would effectively eliminate all current non-desired erosions in the tax base, it would leave open the door for incorporation of future federal erosions which the Alaska Legislature would have to constantly review and excise.

The Inappropriate Apportionment Formula. As explained in Chapter V, the destination sales factor in the current apportionment formula does not truly represent oil and gas production activity in the State. Therefore, the Department of Revenue recommends the second proposal made by Zeifman and Ainsworth for adopting an extraction factor as a part of the State's apportionment formula to measure the value of production in Alaska. Specifically the Department recommends adopting an extraction factor as a substitute for the sales factor or alternatively as an additional fourth factor to the uniform apportionment formula. This extraction factor would be a fraction, the numerator of which would be the number of units of oil and gas (determined by BTU parity) produced in Alaska and the denominator would be the number of units of oil and gas produced everywhere. Thus if the total units of oil and gas produced in Alaska were 10,000,000 for a particular oil corporation and its total units of oil and gas produced everywhere were 50,000,000, its extraction factor would be:

$$\frac{10,000,000}{50,000,000} \text{ or } 20\%$$

First this solves the problem of the reduction in the apportionment formula by the current sales factor. The current sales factor only assigns to Alaska the sales of petroleum products actually destined in Alaska. Since destination sales in Alaska are insignificant compared to total sales, the resulting small sales factor reduces the overall apportionment formula. By substituting or adding the extraction factor the overall apportionment formula is increased, resulting in more taxable income being assigned to Alaska. Specifically, Zeifman and Ainsworth show that the origin oriented extraction factor is substantially larger than the current sales factor and that its use would add more than 50 million dollars of Alaska apportioned taxable income for the 13 largest oil corporations doing business in Alaska. The pertinent table showing this effect follows:

APPORTIONMENT RATIOS BASED ON THREE FACTOR FORMULAS
I.E. PROPERTY, PAYROLL AND SALES, AND
PROPERTY, PAYROLL AND EXTRACTION
(Worldwide Ratios for 1975)

<u>Company</u>	<u>3 Factors Sales Destination</u>	<u>3 Factors Origin</u>	<u>Tax Base Differences (Origin-Destination) \$'s</u>
A	.003	.008	4,370,713
B	.002	.002	1,711,849
C	.021	.034	8,979,919
D	.010	.011	21,705
E	.013	.027	2,628,601
F	.014	.025	2,031,795
G	.001	.002	5,869,087
H	.006	.010	3,888,539
I	.004	.009	455,548
J	.005	.011	3,982,088
K	.014	.030	2,669,889
L	.032	.056	11,769,255
M	.035	.048	4,229,968
		TOTAL	52,608,956

In addition to the increased apportioned tax base which the extraction factor would create, it would for the first time provide a measurement of production activity in Alaska since the factor is based upon units of oil and gas produced. Currently, the sales factor only measures marketing activity of oil and gas corporations since it is based upon destination sales.

By making this modification to the formula instead of adopting a separate accounting method, the State could continue combining the total taxable income of the unitary business. By looking at the entire enterprise and eliminating inter-company transactions, it effectively eliminates the effects of inter-company manipulations of income and expense.

The Department does not recommend two other possible modifications of the apportionment formula or the use of separate accounting because of the problems which they present. One of the possible alternatives would be to change the definition of "destination" in assigning sales for purposes of the sales factor. A change in the definition of "destination" could be made so that a sale would be destined in the state once the oil and gas produced was transferred to a transportation facility. Although this modification would measure production activity in the state, its application would present extreme administrative difficulties. For example, some sale price would have to be assigned for the oil and gas produced and that price would either be the final sales price to the consumer or an imputed price at the point where the production is transferred to the transportation facility. If the first course was chosen, the Alaska production would have to be traced all the way to the market and a final sales price determined for each unit of oil and gas produced in Alaska. In the second case, a value would have to be assigned to all production everywhere at the point where it was transferred to the transportation facility. Each alternative would be so difficult as to be unworkable.

Another alternative modification of the apportionment formula which is not being recommended would be the elimination of the sales factor entirely from the apportionment

formula. The remaining two factors of payroll and property would then be used to apportion income to Alaska. The elimination of the sales factor would benefit Alaska since it is this factor which reduces the overall apportionment formulas of most multistate oil and gas corporations. As shown by Zeifman and Ainsworth, the use of the two factor formula would add \$25 million dollars of Alaska taxable income.

Although the use of a two factor formula would prevent the present reduction in the apportionment formula using the sales factor, it would not measure the value of oil and gas produced in the state. Thus, the corporation's activity in the state would be measured solely by the corporation's property and payroll in Alaska.

In addition to the two alternative modifications of the apportionment formula, the Department also strongly recommends against the use of separate accounting.

Separate accounting separates or segregates the net income of a business into geographical units. In effect, the business activities in one state are treated as if they were carried on by a totally separate business. The separate accounting method involves the specific identification of only those items of income and expense which relate to the taxpayer's activity solely in a particular state.

Theoretically, separate accounting measures the net income of the business earned within the state. In practice it does not. The reason it does not stems from the way that large modern businesses, especially large integrated multinational corporations, operate.

The entire enterprise is operated as a unit with the profit being earned only by the entire operation as a whole. Thus the whole enterprise is actually more than the sum of the parts since each part is in being only to contribute to the entire unitary business. The net profit is actually the final result of the continuous series of income and expense transactions among the various component parts of the business. With regard to an integrated multinational oil corporation, the net income is not earned by any particular phase of the operation such as production, transportation, refining or marketing. Each segment contributes to the whole, and the net income is only reflected after the sale to the consumer and the contribution of each part of the business.

Because of the realities of modern business operations, a separate accounting method opens the doors to widespread tax avoidance. With a multifaceted business acting through different divisions, affiliates and subsidiaries, it doesn't matter to the overall enterprise whether a particular division is shown to make a profit or loss as long as in the end

a profit is made for the company as a whole. In a real sense the profit or loss of a particular division can be made to appear any way that the enterprise wants it to appear.

For example, when goods transferred as raw products from one division to another are produced and then transported to be refined and then transferred to market, the amount charged to each segment of the business can be anything that the enterprise finds in its best interest to charge. Likewise as the parent corporation or another division provides management, accounting, legal or other related services for another division or affiliate, the same flexibility exists for determining the amount of fees to be charged. Income and expense can be effectively shifted from one part of the business to another. This shifting of income and expense does not take place through a handful of easily recognizable transactions, but through a series of thousands of transactions a day which amount to millions for an entire year. Also, these transactions are made not just between a handful of corporate entities, but through literally hundreds of divisions, affiliates, and subsidiaries. With such a myriad of corporate entities and transactions, it is difficult, to say the least, to determine what is the "true" net profit earned by one entity or geographic part of an entity.

As Zeifman and Ainsworth observed about separate accounting:

COMPANIES WHICH USED SEPARATE ACCOUNTING IN 1973, 1974, AND 1975,
THE TAXABLE INCOME ASSIGNED TO ALASKA BY THAT METHOD AND
ALTERNATIVE METHODS WHENEVER POSSIBLE

	<u>1973 TXBLE. INC.</u>	<u>1974 TXBL. INC.</u>		<u>1975 TXBL. INC.</u>	
	<u>Sep. Acctg.</u>	<u>Sep. Acctg.</u>	<u>Apport.</u>	<u>Sep. Acctg.</u>	<u>Apport.</u>
A P.O.	(4,688,123)	(15,997,275)		N.A.	2,870,420
Sub ₁	0	0		N.A.	N.A.
D Sub ₁	N.A.	N.A.		N.A.	N.A.
E Sub ₁	N.A.	(2,294,094)	(6,060,885)	(23,721,209)	N.A.
H P.O.	0 ¹	0 ¹		N.A.	(375,032)
Sub ₁	0 ¹	0 ¹		N.A.	(13,525,636)
I P.O.	0 ²	0 ²		0 ²	N.A.
J P.O.	(1,829,201)	(2,784,713)		N.A.	3,027,848
K P.O.	(1,979,609)	(16,248,961)		(12,748,645)	2,494,124
Sub ₁	(165)	(165)		(170)	N.A.

FOOTNOTES

P.O. - Parent corporation only.

1 - Not greater than zero for these cases.

2 - Known to be a negative amount.

COMPANIES WHICH USED SEPARATE ACCOUNTING IN 1973, 1974, AND 1975,
THE TAXABLE INCOME ASSIGNED TO ALASKA BY THAT METHOD AND
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	<u>1973 TXBLE. INC.</u>	<u>1974 TXBL. INC.</u>		<u>1975 TXBL. INC.</u>	
	<u>Sep. Acctg.</u>	<u>Sep. Acctg.</u>	<u>Apport.</u>	<u>Sep. Acctg.</u>	<u>Apport.</u>
A P.O.	(4,688,123)	(15,997,275)		N.A.	2,870,420
Sub ₁	0	0		N.A.	N.A.
D Sub ₁	N.A.	N.A.		N.A.	N.A.
E Sub ₁	N.A.	(2,294,094)	(6,060,885)	(23,721,209)	N.A.
H P.O.	0 ¹	0 ¹		N.A.	(375,032)
Sub ₁	0 ¹	0 ¹		N.A.	(13,525,636)
I P.O.	0 ²	0 ²		0 ²	N.A.
J P.O.	(1,829,201)	(2,784,713)		N.A.	3,027,848
K P.O.	(1,979,609)	(16,248,961)		(12,748,645)	2,494,124
Sub ₁	(165)	(165)		(170)	N.A.

FOOTNOTES

P.O. - Parent corporation only.

1 - Not greater than zero for these cases.

2 - Known to be a negative amount.

With these negative taxable incomes assigned to Alaska, it is not surprising that major multinational corporations have vigorously lobbied several state legislatures and Congress for the authority to use separate accounting in the calculation of state income tax. As stated by Zeifman and Ainsworth in their report:

...a large lobby group of multi-national corporations known as COST (Committee on State Taxation) has been formed to press both the United State Congress and State Legislatures for legislation permitting them to use separate accounting techniques for State tax purposes. It is also noteworthy that COST is comprised of ninety-two of the one-hundred largest corporations in the United States and is both an advocate of separate accounting forms of taxation as well as an opponent of the joint audit program of the Multistate Tax Commission.
[footnote omitted]

Additionally, increased auditing by the Department of Revenue is not an answer to what would be widespread tax avoidance by multinational corporations. Indeed, even the federal auditors are not able to police a separate accounting system. Again quoting from Zeifman and Ainsworth:

...proponents of separate accounting point out that the Department of Revenue would have the legal authority to recompute all of the transactions among all of the parties and their affiliates. However, for the Department of Revenue to do so would involve an extraordinarily complex series of cost-accounting types of audits of each affiliated service organization. Such audits would be similar to the complex audits used only rarely and as an extraordinary remedy by the Federal Government under Section 482 of the Internal Revenue Code.

On a Federal level, under Section 482, the Secretary of the Treasury has long had the power to re-allocate income and deductions among affiliated companies when "necessary in order to prevent evasion of taxes or clearly to reflect the income of any of such organizations." However, the difficulties of administering Section 482 has been found so great as to limit severely the usefulness of this power, even as an extraordinary remedy on a Federal level. Under the circumstances, since the problems posed by separate accounting on a State level are even more complex than on a Federal level, it is our opinion that individual states simply are not capable of developing sufficient audit capacity to rely on such extraordinary types of audits for the general enforcement of their tax programs. This is not only true with states such as Alaska, which has a comparatively small audit staff, but is also true with respect to such states as California, which has the largest and most experienced audit staff in the United States. [footnote omitted]

Thus, although separate accounting would theoretically present an accurate method of measuring net income earned in the state, in practice it presents taxpayers with the utmost in tax-avoidance possibilities.

Even if the problem of tax avoidance could be solved by ferreting out and overturning all corporate manipulations, separate accounting would still not work in Alaska's best interests. With potential depressed pricing of North Slope oil as described in Chapter V, the net income "earned in Alaska" by oil and gas corporations could be legitimately shown to be reduced while other unregulated segments of the business would be shown more profitable. The use of separate accounting would not take into account the relative value of the unrefined product to the rest of the business

or the contribution of the rest of the business to the portion of the income due to activity in Alaska. Separate accounting would look only to the one segment in isolation of the prices actually received.

B. RECOMMENDATIONS FOR THE PRODUCTION TAX

Effects on the economics of oil production operations.

The Department of Revenue recommends perfecting the "stair step" approach as a means of eliminating effects of the production tax on the economics of oil production operations. The key to doing so is not found by creating a series of "steps" and rates that succeed in this for any one area of the State, such as Cook Inlet. As explained in Chapter V, a well producing 1000 barrels a day may be quite a money maker in Cook Inlet but be mediocre or even marginal in other areas of the state such as the Interior or North Slope. Consequently the "stair steps" that succeed for the Inlet won't eliminate the economic effects of the tax elsewhere. Conversely, "stair steps" designed to eliminate those effects from production on the North Slope would give too much away to production in the Inlet.

To eliminate this difficulty, the Department of Revenue recommends an Economic Limit Factor (ELF), based on the ratio of the rate at the true economic limit to the current production rate, as a mechanism for scaling down the tax rate as the production declines toward the economic limit. This would be done by multiplying a basic tax rate times the difference between unity (the number, one) and the ratio of rate at the limit to current rate. As the following table illustrates, the ELF produces a smooth, continuous series

of tax rates, barrel by barrel, when applied to any basic tax rate, which scales the actual (effective) tax rate down to zero at the economic limit.

Scale Down of Effective Tax Rate
by an Economic Limit Factor
[ELF = 1 - Rate at Limit/Current Rate]
(rate at limit = 200 B/D per well)

Current Rate (B/D per well)	Economic Limit Factor	Effective Tax Rate w/ an 8% Base	Effective Tax Rate w/ a 10% Base	Effective Tax Rate w/ a 12% Base
10,000	0.9800	7.84	9.80	11.76
8,000	0.9750	7.80	9.75	11.70
6,000	0.9667	7.73	9.67	11.60
5,000	0.9600	7.68	9.60	11.52
4,000	0.9500	7.60	9.50	11.40
3,000	0.9333	7.47	9.33	11.20
2,000	0.9000	7.20	9.00	10.80
1,500	0.8667	6.93	8.67	10.40
1,000	0.8000	6.40	8.00	9.60
800	0.7500	6.00	7.50	9.00
600	0.6667	5.33	6.67	8.00
500	0.6000	4.80	6.00	7.20
400	0.5000	4.00	5.00	6.00
350	0.4286	3.43	4.29	5.14
300	0.3333	2.67	3.33	4.00
250	0.2000	1.60	2.00	2.40
225	0.1111	0.89	1.11	1.33
200	0.0000	0.00	0.00	0.00

Notice how the effective tax rate does not begin to decline rapidly until production gets relatively close to the economic limit. In the table above with an assumed rate at the limit of 200 barrels a day per well, the effective rate is 98 percent of the base rate with 10,000 barrels-a-day wells. This percentage has merely dropped to 90 percent when the

well productivity is down to 2000 barrels a day. In other words, the ELF keeps the effective rate high while the current production rates are much larger than the economic limit rate, and thereby keeps the tax rate from scaling down too soon while the economics of the production operation remain quite sound. As the table shows, this is true regardless of what the base rate is.

On the other hand, the ELF really scales the rate down when the economic limit begins to get near. Thus, while the effective rate is 90 percent of the base rate at 2000 barrels a day in the table, it drops to 75 percent of the base rate at 800 barrels a day, to half of the base rate at 400, to one-fifth of the base rate at 250, and to zero at 200.

If the tax law conclusively sets the rate at the economic limit at some specific rate like 200 barrels a day per well, the ELF becomes simply one more economically rigid structure like the present "stair steps." It would not respond to the great regional differences in economic scale for production operations in Alaska. But the great advantage of the ELF over any specific set of "stair steps" is that it can be tied to the actual economic condition of a property anywhere in the state, thanks to using the ratio of production at the economic limit of that property to its current production rate.

The Department of Revenue recommends that the statute specify exactly how the Department should calculate the production rate at the economic limit. Basically, all that is involved in that calculation is finding out how many barrels of non-royalty oil it takes to have a total value in the field exactly equal to the total production costs for the property at the level of operations that will prevail at the economic limit. A rebuttable presumption should be created regarding the percentage by which the current level of operations would be cut back by the oil producer to a "bare bones" operation at the economic limit, which would put the burden on the taxpayer, instead of the Department, to come forward to support its position about what this percentage will be. The Department also recommends avoiding the difficulties of forecasting real or inflationary increases in oil prices and operating costs during the remaining economic life of the property; it proposes to do this by using the prevailing costs and world-market oil prices (netted back to the field) at the time it determines the production rate at the property's economic limit. It should be noted that with the ELF it is unnecessary to have more than one base rate for either the cents-per-barrel or the percent-of-value tax. Since the ELF already ensures a proper scaling down of the rate, multiple rates would only scale the tax down a second time, which would forfeit tax revenues that need not be foregone.

The Department also considered the possibility having a single rate for the cents-per-barrel tax and a single percentage for the percent-of-value tax using a type of "escape hatch" mechanism to scale the tax down after production reached some specified economic threshold near the true economic limit. It rejects this notion because the sudden tax benefits from crossing the threshold would create an incentive for a producer approaching that crucial point to hasten its arrival artificially.

Protecting State revenues from the effects of artificially low oil prices. As explained in Chapter II, the cents-per-barrel tax protects the State's production tax revenue by setting a "floor" for that revenue. If the price is set below a certain level, the cents-per-barrel tax becomes payable instead of the percent-of-value tax.

The Department of Revenue recommends raising the "floor" from its present level, which corresponds to \$6.10 a barrel for Prudhoe Bay oil, to a level more closely reflecting the full market value of that oil. At the present level of cents-per-barrel rates, the State's production tax income would have to suffer considerable reduction as the result of oil prices artificially lowered below the free-market price before the cents-per-barrel tax would begin working to prevent any further reduction.

To prevent the "floor" from losing value through time, it should escalate. The present escalator is the Wholesale Price Index for crude oil, but this Index reflects the aberrations of the present system of federal price controls. For example, the Index on occasion has changed solely as the result of a change in the estimated ratio of "old oil" to "new oil," when there was no change in domestic oil prices at all. The Department of Revenue recommends replacing the Index with the Gross National Product deflator, which would allow the "floor" to keep pace with nationwide inflation. Because world oil market prices may rise at a different rate than American inflation, it may be desirable to adopt an escalator that more closely follows world oil market conditions. The Department accordingly recommends using changes in the state sales price (exclusive of premiums and discounts for Saudi Arabian (31° API gravity) crude oil as the basis for escalating the cents-per-barrel tax.

The Department of Revenue also recommends modifying the cents-per-barrel tax so that it increases more and more as the price is further and further below the "floor" price that initially brings the cents-per-barrel tax into play instead of the percent-of-value tax. These increases would serve to offset in large part the State's cash royalties lost as the result of oil prices below the "floor" price.

To illustrate exactly what the Department's proposal

is, suppose the ELF recommendation is adopted, the single base rate for the percent-of-value tax is 10 percent, and the "floor" price is \$7.50. A statute incorporating the proposal would provide that the tax is 10 percent of the field price or 75 cents a barrel, whichever is greater. If the tax were payable on the cents-per-barrel basis, there would be an additional surtax equal to the final product of multiplying 11.42857 times the State's "Cash Royalty Fraction" times the tax difference between 75 cents per barrel and 10% of price. The "Cash Royalty Fraction" would be the number of barrels whose cash equivalent was paid to the State as royalty instead of being taken in kind, divided by the total number of barrels produced. This fraction naturally excludes State royalty oil taken in kind, and it would be zero when the State has no royalty interest at all in the production. The effect of this is to prevent the offsetting of "lost" royalty income when the State shouldn't be doing so, as when it doesn't own the land or when it sells royalty oil

If the ELF were incorporated into this proposal (and it should be incorporated), it should apply to the percent-of-value tax and to the 75 cents-per-barrel, but not to the surtax offsetting lost cash royalties. Not applying the ELF to the surtax creates an additional cost which advances the true economic limit; however, the agent causing the artificially low price can return the true economic limit

back to its original place by simply ceasing to manipulate the price and allowing it to rise to the full market value. Then the percent-of-value tax would take over, the surtax would no longer be paid, and the ELF that is applied to the percentage tax would keep the tax from advancing the true economic limit. In other words, the surtax provides an incentive to any would-be price manipulator to give the oil its fair (free market) price.

There may be a potential problem, however, with that portion of the recommendation regarding the "lost value" surtax. This would be due to the fact that there seems to be no way to avoid a direct reference to what we call the State's Cash Royalty Fraction. Without some such reference the surtax would apply to "lost" royalties for lands not owned by the State, where someone else will be the royalty owner. The surtax would also apply when the State's royalties were taken in kind, unless reference is made limiting it to the State's royalties taken in cash. This reference may engender a legal challenge to the surtax, and we recommend a review of this matter by the Attorney General.

In the event his review indicates that the surtax would be legally inadvisable, the Department of Revenue still would make its other recommendations to protect production tax revenues at least from artificially suppressed oil prices. Coupled with the ELF recommended in the preceding

section, this would assure the State of receiving fair production tax revenues despite any federal pricing actions or corporate profit-shifting activities, while simultaneously accommodating the case where a field or property is approaching its economic limit.

Protecting State revenues from the effects of artificially low gas prices. The Department of Revenue recommends an escalating "cents-per-Mcf" tax for gas, to be used in conjunction with the present percent-of-value tax. The percentage rate should rise to eight percent to achieve rate parity with oil, and the cents-per-Mcf rate should be six cents. The higher tax would be payable.

The Department would propose an ELF factor for the gas production tax, but because of the difference in the nature of production operations between oil and gas, the Department has not yet ascertained what an appropriate factor would be nor how it should be determined. As none of the major Cook Inlet area gas fields is anywhere close to reaching its economic limit, and since major production of gas for sale from Prudhoe Bay is still a number of years in the future, the Department recommends using some of this available time to pursue this subject further.

Flared gas. The Department of Revenue recommends that flared gas be taxed. Amending the statute to include flared

gas would do little good if percentage-of-value remains the sole basis for the gas production tax. The Department recommends a tax rate twice as high as the ordinary rage; if the Department's six cents per Mcf proposal above is adopted, this would mean 12 cents an Mcf for flared gas.

C. RECOMMENDATIONS FOR THE PROPERTY TAX

As explained in Chapter V, there are four problem areas in the otherwise well functioning property tax: the omission of certain important kinds of oil and gas related properties from the definition of taxable property; present uncertainty about how pipelines should be valued; the static nature of the \$1500 per-capita limitation of municipal taxation; and the extent to which credits against the State tax should be allowed for municipal property tax payments.

The Uncertainty of Pipeline Valuation: As shown in Chapter V, the complex and confusing pipeline valuation portion of the property tax statute has led to litigations and uncertainty in the way that operating pipelines will be valued. In fact, there is even a chance that the depressed valuation method (depreciated-actual cost) might become the rule of valuation rather than the exception. Accordingly, the Department of Revenue recommends repealing the exception providing for a depreciated actual cost approach and retaining only the valuation method based on full and true value with due regard to economic value. If on further examination a better valuation method presents itself, the Department will recommend its substitution.

One alternative, which the Department is not recommending, would be to repeal both of the present valuation methods

and replace them with some specific appraisal technique (such as depreciated replacement cost) for ascertaining the full and true value of normal, operating pipelines. While this would establish one certain valuation method for all pipelines operating normally, its drawback is its foreclosure of applying other approaches (such as the income approach) which might better reflect full and true value in some circumstances.

As an alternative to repealing the exception, the Department does recommend amending that section of the statute to reflect clearly the Department's interpretation of it. The Department's interpretation is that if the present estimate of the economic life of the deliverable reserves is materially shorter than the owner's original expectation, then the exception applies and the pipeline will be valued on the basis of its actual cost with depreciation. Otherwise, it will be valued with due regard to its economic value.

This would insure that in most cases of normal operation of the pipeline, it would be valued on the basis of full and true value with due regard to economic value. It would still mean, however, that a determination would still have to be made as to when the actual economic life was "materially shorter" than the original expectations of the economic life and thus there would still be possibilities that the actual cost depreciated method would apply to normally

operating pipelines.

The Omission of Certain Kinds of Oil and Gas Related Properties From the Definition of Taxable Property. The Department of Revenue recommends expanding the definition of taxable property in the property tax statute to include oil refineries, gas processing plants, LNG facilities and petrochemical operations.

This will mean greater revenues to the State and will not materially affect the investment decisions of a prudent investor.

Recommendation to solve the static municipal limitations. The Department of Revenue recommends that the \$1500 per-capita limitation be tied to an escalator (such as the cost-of-living index) so that the municipal limitation will not lose value over time due to inflation. Thus the municipal limitation will increase as inflationary pressures increase the dollar cost to municipalities of maintaining services to its residents.

Recommendation for the municipal credit. The Department of Revenue recommends that the municipal credit section of the statute be amended to make absolutely clear that taxes paid to municipalities which exceed the limitations set out in AS 29.53.045 and AS 29.53.050 are not creditable

against the State tax, while also making clear that this limitation to the credit does not imply a limitation of the municipal power under AS 29.53.055 to exceed the "\$1500 per-capita" and "225 percent" limitations in the appropriate circumstances.

This will help assure that the municipal tax payments of only oil and gas property taxpayers are not subsidized in those circumstances, which would be the result of crediting the full payment against the State's property tax.

D. RECOMMENDATION FOR THE RESERVES TAX

Assuming that the Trans-Alaska Pipeline begins to transport oil as scheduled in July of this year, the Department of Revenue recommends that the reserves tax terminate on its scheduled expiration date of December 31, 1977.

CHAPTER VII. EFFECTS OF ADOPTING THE RECOMMENDATIONS

A. REVENUE EFFECTS OF CORPORATE INCOME TAX RECOMMENDATIONS

As stated in Chapter VI, the Department makes two recommendations on the Corporate Income Tax. These recommendations are the adoption of a world-wide "book income" tax base, and the inclusion of a new apportionment factor based upon production. These recommendations essentially follow the proposals made by Zeifman and Ainsworth.

In their report, "The Taxation of the Petroleum Industry Under Alaska's Corporate Income Tax," Zeifman and Ainsworth discuss the revenue effects of the adoption of their proposals. With the adoption of a world-wide "book income" tax base and a three factor apportionment formula based upon property, payroll and extraction, they estimated a four-fold increase in corporate income tax revenues paid by oil and gas corporations. Specifically, for example, they found that their proposals would bring in an additional 10.9 million dollars in corporate income tax revenue for 1975. Since oil and gas corporate income taxes collected in 1975 were \$3.5 million dollars, the total corporate income tax revenues under the proposals would have been \$14.4 million dollars (slightly more than a four-fold increase).

The Department also analyzed the effect of the proposals in reference to the most recent year's corporate returns

and applied the same resulting percentage increase to the Department's projections of income tax revenues from oil and gas corporations in future years. Published figures of world-wide book incomes and production for the major oil and gas corporations in 1975 were used in computing the increase in 1975 revenues.

The Department projects corporate income tax revenues from major oil and gas companies under present law as follows:

Projections of Oil and Gas Corporate Income Tax
Revenues Under Current Law
(millions of dollars)

1978	46
1979	51
1980	54
1981	57
1982	60
1983	63
1984	66
1985	69

Using current data and extrapolating the potential current increases in tax into the future, the Department projects corporate income tax revenues under its recommendations as follows for major oil and gas companies:

Projections of Oil and Gas Corporate Income
Tax Revenues under Proposed Changes
(millions of dollars)

1978	184
1979	204
1980	216
1981	228
1982	240
1983	252
1984	264
1985	276

Obviously to obtain a more definitive forecast of corporate income tax revenues under the Department's recommendations, projections of future world-wide book incomes and production for each of the major oil and gas corporations doing business in Alaska would have to be obtained. The Department plans such a detailed analysis in the near future and will update its forecasts at that time.

B. REVENUE EFFECTS OF PRODUCTION TAX RECOMMENDATIONS

In the preceding chapter, the Department of Revenue recommended raising the cents-per-barrel rate, adopting the Economic Limit Factor (ELF) to replace the present "stair step" structure, and imposing a cents-per-barrel surtax to further mitigate the effects on the State's total petroleum-related revenues due to depressed prices. In Chapter V, three cases (numbers 2, 3 and 4) were presented to show how the present revenue system would be inadequate if prices for Prudhoe Bay oil were to be artificially depressed below market value. They were compared to the free-market case (number 1), and it was shown that by Fiscal Year 1985, the State would receive \$3.88 billion less in Case 2, \$2.39 billion less in Case 3 and \$3.78 billion less in Case 4 than it would receive in a free market situation from production tax and royalty, combined, for the main pool at Prudhoe Bay.

The following table shows how the Department's recommendations (using 8% and \$0.75 as the base tax rates) would reduce the effect of depressed pricing on the State's combined revenues from Prudhoe Bay.

Combined Revenues from Prudhoe Bay Main Reservoir
FY 78 - FY 85
(\$ millions)

	Revenues under Present Tax Structure			Revenues under Recommendations (in All 3 Cases)
	Case 2	Case 3	Case 4	
FY 78	284.0	378.5	241.9	378.8
FY 79	418.5	585.1	381.5	609.2
FY 80	498.2	689.1	473.8	729.0
FY 81	511.3	704.1	506.6	939.1
FY 82	662.5	851.5	679.1	993.2
FY 83	695.1	915.1	734.2	1050.3
FY 84	718.6	941.6	781.6	1110.0
FY 85	734.1	957.1	822.4	1172.5
TOTAL	4522.3	6022.1	4621.1	6982.1

Through November 1976, gas production from those Alaskan fields selling gas in major quantities totalled 124,356,597 Mcf. Pro-rating for the rest of the year and then deducting tax-exempt royalty interests, leaves 118.7 million Mcf. Under the Department's proposal for the gas production tax, the tax on this volume would have been at least \$7.1 million (6 cents per Mcf).

C. REVENUE EFFECTS OF PROPERTY TAX RECOMMENDATIONS

In Chapter VI the Department made four recommendations for change in the property tax. These were the inclusion of oil refineries, gas processing plants, LNG facilities and petrochemical operations in the definition of taxable property; the repeal of the exception for valuing an operating pipeline whose indicated economic life (based on the reserves served by the pipeline) is materially shorter than its physical life; tying the \$1500 per capita limitation of municipal taxation to a cost of living escalator; and ensuring that municipal taxes levied under AS 29.53.055 in excess of the limitations imposed by AS 29.53.045 and AS 29.53.050 are not allowed as credits against the State's tax to the extent the municipal taxes exceed those limitations.

If oil refineries, gas processing plants, LNG facilities and petrochemical operations were included as taxable property, the Department estimates the additional revenues from existing facilities would be as shown in the following table.

Projected Property Tax Revenues
from Existing Oil Refineries
and Gas Processing Facilities
(\$ thousands)

1978	3,307.2
1979	5,699.0
1980	7,910.0
1981	10,110.0
1982	10,173.2
1983	10,173.2
1984	10,173.2
1985	10,173.2

These estimates also include the anticipated Pacific Alaska LNG plant.

In addition the Department has made projections of property tax revenues which would be collected on an LNG plant and related terminal if the El Paso gas pipeline proposal is chosen. These potential revenue are shown in the next table.

Projected Property Tax Revenues
from the Proposed El Paso LNG Plant
and Related Terminal Facilities
(\$ thousands)

1978	-0-
1979	1,186.3
1980	3,292.4
1981	11,678.1
1982	24,605.1
1983	33,362.3
1984	36,315.3

As explained in Chapter V, there is some uncertainty regarding the valuation of normally operating pipelines. The Department accordingly recommends repealing the exception that provides for valuation on a depreciated actual-cost basis. The consequences of not ensuring an appreciating valuation for pipelines - especially the Trans Alaska Pipeline System - are illustrated by the following example.

	Actual Cost Less Depreciation (30 yr.)		Replacement Cost (trended @ 10% per yr.) Less Depreciation (30 yr.)	
	<u>Value</u>	<u>Tax</u>	<u>Value</u>	<u>Tax</u>
1978	5500	110.0	5500	110.0
1979	5317	106.3	5848	117.0
1980	5139	102.8	6219	124.4
1981	4968	99.4	6613	132.3
1982	4803	96.1	7031	140.6
1983	4642	92.8	7477	149.5
1984	4488	89.8	7950	159.0
1985	4338	86.8	8454	169.1

From this the tremendous revenue implications can be seen that would result from the adoption of the Department's recommendation.

2500

AGC 114138

IMPACT OF INCREASED TAXATION ON OIL EXPLORATION
AND DEVELOPMENT IN ALASKA

A Report to the
Alaska State Legislature

March 25, 1977

Tanzer Economic Associates, Inc.



POUCH V
JUNEAU, ALASKA 99811

Alaska State Legislature House of Representatives

PLEASE RETURN TO
DEPARTMENT OF REVENUE
RESEARCH

24 March 1977

All Members
Alaska State Legislature
Pouch V
Juneau, Alaska 99811

Enclosed is a report entitled Impact of Increased Taxation on Oil Exploration and Development in Alaska, the second report prepared by Tanzer Economic Associates, Inc., of New York, pursuant to a contract with Legislative Affairs Agency.

This report includes three areas related to oil taxation in Alaska. They are (a) the historical experience, (b) an update to the prior document, Alaska Prudhoe Bay Oil: Profitability and Taxation Potential, prepared for the Second Session, Ninth Alaska Legislature, dealing with the profitability of oil production in the Sadlerochit formation by Sohio/BP, ARCO, and Exxon, and (c) the benefits and costs to Alaska from increased oil taxation.

Very truly yours,



Hugh Malone
Speaker

HM:jb

TANZER ECONOMIC ASSOCIATES, INC.
ECONOMIC CONSULTANTS
251 WEST 86TH STREET
NEW YORK, N. Y. 10024

(212) 874-8882

CABLE: "TANZECON" NEW YORK

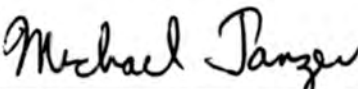
February 3, 1977

Representative Hugh Malone
Vice-Chairman
Subcommittee on Oil and Gas
Leasing and Tax Policies
Alaska State Legislature
Juneau, Alaska 99811

Dear Sir:

I have the honor to transmit to you the attached report on "Impact of Increased Taxation on Oil Exploration and Development in Alaska." This report was prepared under contract with the Legislative Affairs Agency of the Alaska State Legislature.

Yours sincerely,



Dr. Michael Tanzer,
President

MT:lah

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SUMMARY

The purpose of this Study was to analyze the possible impact of increased State oil taxation on oil exploration and development in Alaska. The background for the Study was the dire warnings of the oil companies that substantially increased State taxes will hurt their future efforts in Alaska. To help assess these claims, three different approaches were taken.

First, an examination was made of a variety of historical cases in which major oil tax changes have been proposed or carried out, focusing on the impact on the countries involved, including the reactions of the oil companies. Second, the likely profitability of Prudhoe Bay crude oil under various tax assumptions was reassessed, and this was compared with the companies' tax and profitability prospects in other producing areas which might be competitive with Alaska. Third, an analysis was made of what the costs and benefits of increased taxation might be for the State of Alaska, in terms of possible reduced exploration and development versus increased tax revenues from Prudhoe Bay alone.

In the first part, the Study examined the experience of oil tax increases in Iran in the 1950s, Venezuela in the 1960s, and Indonesia, Malaysia, the United Kingdom, Norway, the Netherlands, West Germany and New Zealand in the post-1973 period.

It was shown that there is no simple pattern of oil company reaction to such changes as regards oil production, exploration and development. Moreover, it was argued that this is not surprising since many other factors besides a change in tax rates affect the companies' incentives. The one commonality in these cases, however, was that government attempts to increase oil taxes almost invariably brought forth company reactions that this will be harmful to the country. The Study therefore concluded that while such "warnings" are normal forms of company "propaganda", they need to be taken with a large grain of salt, and the specifics of each situation carefully analyzed.

Towards this end, in the second approach the Study first reassessed the profitability of Prudhoe Bay oil originally made in the "Tanzer Report". The reassessment was based on conservative production and investment estimates made by a New York brokerage firm, for the most probable oil price, \$13 per barrel in Los Angeles. Three State oil tax cases were considered: the present State tax structure; a "50% State take" case where Alaska gets (including royalty and severance) 50% of the oil pie; and a 50% State income tax case (in addition to royalty and severance). The analyses showed that under the present State tax structure the companies' DCF profit rate would be 29% per year, while even with a 50% State income tax it would be 19% per year (with a 23% profit rate for the intermediate 50% State take case). The companies' per barrel profits (and their percentage share of the oil pie) were estimated as

follows: present tax structure, \$2.70 (37%); 50% State take, \$1.80 (25%); and 50% State income tax, \$1.40 (19%).

Oil company profitability and taxation policy in other major oil producing areas were then analyzed to assess Alaska's competitive position. It was shown that generally company profits elsewhere were much less than in Alaska, even under the highest State income tax rate considered. In the OPEC countries of the Middle East, North Africa and Venezuela, the companies' profits amount to about 15 to 30 cents per barrel, giving them only 2% of the oil pie, with 98% for the governments. In Indonesia, which allows the highest profit among OPEC members, \$1.00 to \$1.50 per barrel, the companies get about 12% of the oil pie and the Government 88%.

Outside of the OPEC countries, in Canada the companies get about \$1.25 per barrel, or 11% of the oil pie, which is less than they would get from Prudhoe Bay under a 50% State income tax. Even in the North Sea, where it is estimated the companies will get about \$3.50 per barrel, this is shown to be related to the very large investment costs there, which are twice as great as in Prudhoe Bay; on a DCF basis the companies' North Sea profit rate is estimated at 19% per year, or about the same as for Prudhoe Bay with a 50% State income tax.

The Study also discussed Alaska's other advantages to the companies. The fact that in a world of crude oil scarcity assured supplies are becoming increasingly vital to the companies to protect their refining and marketing investments makes the

possession of U.S. oil particularly valuable to them. This is reinforced by the trend toward 100% nationalization by OPEC members and "participation" by governments in the North Sea (and even Canada). In the light of all these factors, it was concluded that substantial increased State oil taxation is not likely to end the attractiveness of Alaska to the oil companies as a place for additional exploration and development.

Finally, in a third approach, on the hypothetical assumption that the latter conclusion is wrong, the Study tried to assess the benefits and costs to Alaska from increased oil taxation. The benefits would be the direct ones of a total of \$15 to \$21 billion in increased State revenues from the main Prudhoe Bay formation alone (or \$750 million to \$1,100 million per year). The indirect benefits would be the potential "multiplier" effects on economic development, since the increased taxes would stay within the state rather than be exported as oil company profits and federal taxes. The "costs" would be whatever exploration and development were cut off by the increased tax rates. The Study estimated that for the most critical function, exploration, the increased revenues could likely pay for any such losses; for the much larger development effort, once oil is found financing is readily available. (It was also noted that since the State has a lower cost of capital than the oil companies' target profit rates, more development of marginal oil fields might take place if the State participates than if development were left solely to the companies.) The overall

conclusion was that the benefits of increased State taxation are clear and very large while the costs are unclear and likely to be much less sizeable.

In an afterword to the Study, an overall strategy for State oil policy was discussed. It was suggested that the State should substantially increase its tax rates; it should temporarily cease leasing its potential oil-bearing lands; it should invest some of the increased tax revenues in a complete exploratory survey of its lands; and following such a preliminary inventory of potential, it should either directly contract for further exploration or work with oil companies on a joint venture basis. While this might not lead initially to the fastest possible pace of oil resource development, it was shown that other oil producers like Alberta, Canada and Norway have from their experience become wary of too rapid oil resource development.

IMPACT OF INCREASED TAXATION ON OIL EXPLORATION AND DEVELOPMENT IN ALASKA

I. INTRODUCTION

Consideration by the Alaska State Legislature in the last session of increased taxation on oil profits has brought forth numerous dire warnings from the oil companies that such measures will make Alaska "unattractive" as a place for future oil exploration and development. As The Anchorage Times reported in January, 1976, with regard to a proposed "excess profits tax", "leaders of the oil industry appear to be just as certain that the tax would throttle further interest in Alaska exploration. Investment funds would no longer be available here because they could be used more profitably elsewhere."¹ More recently, this theme was reiterated by a Vice President of Sohio, who spoke in Anchorage of a modern version of the fable of "the little red hen" which makes all the bread "without the benefit of other barnyard dwellers--who are standing ready to charge 'excess profits' and help consume the finished loaves."²

Given this background, the aim of the present study is to attempt an objective assessment of the likely impact of increased State taxes on future oil exploration and development in Alaska. The study is divided into three parts. The first (Chapter II) examines a variety of historical cases in

which major tax changes have been proposed or carried out, focusing on the impact on the countries involved, including the reactions of the oil companies. The second part (Chapter III) analyzes the comparative tax position of other countries and states today, and the resulting profitability of crude oil production which might be competitive with Alaskan oil. The concluding part (Chapter IV) deals with what the costs and benefits of increased taxation might be for the state of Alaska, in terms of possible reduced exploration and development versus increased tax revenues from existing oil fields.

II. HISTORICAL EXPERIENCE OF GOVERNMENTAL CHANGES IN OIL TAX RATES

In this chapter we make no pretense of presenting a complete analysis of all the historic experiences of governmental changes in oil tax rates. The oil industry is so widespread and has such a long history of acrimonious tax disputes that a complete analysis would be far beyond the resources available for the present study. Instead, after an examination of some of the available literature, we chose a few examples from the post-World War II period prior to the October 1973 jump in oil prices, and several others from more recent experience. We believe that this sample, while not definitive, is illustrative of the kinds of reactions which have taken place in this highly controversial area.

By way of introduction, it should be noted that, by its nature, the question of the impact of tax changes on oil company behavior is a very difficult one for the outside observer to answer. Many factors besides the level of government taxation can affect the willingness of oil companies to invest in exploration and development or to produce oil in any given state or country. Among the most important of these other factors are the chances of finding sizable amounts of oil, the expected finding and development costs, the individual company reserves and costs of production from these existing reserves, and the

comparative tax rates and potential profitability in other states and countries where oil might be sought or produced; for some of these factors the outsider has little if any information.

Thus, it may well be that where a government seeks to raise oil tax rates to such a level that it appears less profitable to the oil companies to explore and develop or produce in that country than in other prospective areas, the changed tax rates can be decisive in reducing exploration or production. On the other hand, in examining a particular case, it may also be the fact that increased taxes are associated with declining exploration or production, but are not the real causes; just as we can find cases where increased taxation is historically associated with increased production, but again other factors are operative. Hence, to truly estimate the impact of increased taxes in any particular case, one must examine the specific context in great detail.

Nevertheless, as we think the following sample of cases will show, while increased taxes may or may not be the cause of declining exploration and development or production, there is one effect almost invariably caused by such tax changes. Namely, an almost automatic reaction of the oil companies to claim that such increased taxation will force them to look elsewhere for increased future production. These claims are sometimes backed up by actions, aimed at getting the country to rescind the tax increase, such as temporarily cutting present

production or reducing exploration and development efforts. Thus, while the struggle between the oil companies and the governments over increased taxation is a deadly serious matter involving huge sums, it is helpful to recognize that some of the actions and much of the rhetoric (on both sides) is "theater", aimed at improving a bargaining position, and often needs to be taken with a very large grain of salt.

A. Major Oil Tax Changes Prior To October 1973

Perhaps one of the most dramatic confrontations over attempted tax increases took place in Iran in the early 1950s, between the Government and British Petroleum (at that time named the Anglo-Iranian Oil Company). The background to this tax confrontation was that up to 1948 the division of oil profits in Iran between BP (which had a virtual monopoly of Iran's oil resources) and the Government was about 83:17 (in favor of BP).¹ The Iranian Government sought a higher royalty rate and a more favorable division of income, and after prolonged negotiation in 1949 BP agreed to a roughly 70:30 split (still in its favor).² However, by that time the principle of a 50:50 split had been established in Venezuela, and it soon spread to Saudi Arabia and the rest of the Middle East. Despite this, BP refused to budge, and its intransigence led to the complete nationalization of its Iranian oil holdings by the Mossadegh Government in 1951.

Several steps in this sequence are instructive. First, at the height of the 1951 dispute, Iran's Ambassador in London explained the view of his Government in an official statement:

. . . Persia [the name for Iran at that time] has not, by any standards, received a fair and reasonable share of her vast oil resources Repeated attempts on the part of Persia in the last few years to obtain a just share of the oil profits, and an honourable and equitable part in the control and administration of this vital concern to Persia, have not met with that spirit of partnership and far-sighted co-operation so essential to the smooth working of a national enterprise of this calibre.³

While BP refused to improve its offer to the Government, and Iran began to move towards nationalization, the company made no public statement about the reasons for its unwillingness to improve on the 70:30 profit split. But the United States Ambassador to Iran at that time, Henry Grady, later explained what, in his view, was happening:

The company [BP] said, "No, we will make no further concessions." The point of view of the company was that if they made any concessions, that would be a show of weakness [Their] slogan was, "When they need the money bad enough, they will ratify." Well, I happen to know--I knew it from many sources--that that was the slogan. The theory was: they'll have to accept because they need these royalties to carry on--and they do. That was their position. I call that a semi-colonial, at least --if not colonial--point of view.⁴

Second, despite BP's view that Iran would have to give in, it did not, and even a Western boycott of Iranian oil after the nationalization, which virtually ended her exports of oil, failed to bring the country to its knees. Only a coup, organized by the U.S. Central Intelligence Agency, finally overthrew the Mossadegh Government in 1954 and forced the denationalization of Iranian oil.⁵ Ironically, as part of the new order, BP was forced to share the oil with a number of other companies, primarily from the United States, and retained only 40% of the concession.⁶ Moreover, the new consortium which was formed gave the Iranian Government the same 50:50 profit split that BP had originally refused and which led to its nationalization.

Finally, despite this sharp oil tax increase, Iranian production then rose rapidly. Thus, by 1957 it had passed the

1950 peak, and in the next six years it more than doubled; by 1970 total production was six times as great as the pre-nationalization peak.⁷ The basic reason, of course, for this rapid growth was that the cost of production of Iranian crude oil, like that of most of the Middle East, was relatively low, and its tax rates were no higher than the other major Middle Eastern producing countries, all of which enjoyed rapid growth in production after World War II.

A second interesting historic tax change case is that of Venezuela in 1966, when the Government was seeking to increase its share of oil profits. The background here was that during the 1960s oil prices were generally falling, and the argument was made that such a tax increase would hurt the country rather than help it. As Petroleum Intelligence Weekly (PIW), an authoritative oil industry trade journal, stated at that time:

If Venezuela pushes the new reference price system through, it could basically alter the current competitive position of Venezuelan oil vis-a-vis oil from North Africa and the Middle East, oil circles note. One observer summed it up this way: "If Venezuela establishes a tax price higher than the current realizations, this will merely raise the cost of Venezuelan oil to the companies. . . . With higher cost through the new tax system, Venezuelan oil will be that much less competitive, production will decline, new oil investment will shrink to zero and the country will continue to lose position in world wide markets."⁸

Again, Exxon, the principal producer in Venezuela (through its subsidiary, Creole Petroleum) gave similar warnings in an attempt to ward off the increased taxes:

The reasons why Venezuelan crude oil is increasingly unable to compete for markets with crude from the Middle East were starkly outlined by Esso's subsidiary, Creole Petroleum, in a paper recently presented to the Venezuelan congress and subsequently released to the press by congressmen. Venezuelan crude production, stagnating over the past years in relation to the Middle East, is actually down 2.8% below 1965 levels so far this year.

This decline, coupled with the Venezuelan government avowed goal of increasing taxes on oil, has resulted in what may be described as a national debate on the future of the oil industry in that country. No final decision has been reached on new taxes to date. But Creole in its document marshals facts to support its argument that additional taxes will only cripple an industry already handicapped in maintaining market outlets.⁹

Despite the warnings, the Venezuelan Government persevered and negotiated a settlement which involved roughly a 5 percentage point increase in its share of oil profits, from 67% to 72%.¹⁰ After this change, again according to PIW:

The big question remaining in Venezuela: Whether production will start going up now that the settlement has been achieved. The question is critical for Venezuela because a slowdown in output, of course, would reduce the government's income. The Minister told the nation that production could be expected to rise between 3% and 4% annually over the next five years. But oil companies point out that they have given no guarantees on production levels. And in view of this year's experience (output is down some 3.55% below the same period a year ago), it's not certain that output in the future will even remain at current levels.¹¹

In fact, production did increase gradually in the next five years, although the rate of increase was about half that predicted by the Venezuelan Government.¹² Here again, the basic reason would seem to be the competitive advantage enjoyed by the very low cost of production of Middle Eastern crude oils.

After the settlement was reached, a columnist for PIW

was refreshingly candid in his statement about oil company tactics for warding off tax increases:

Every time Venezuela has changed its taxation structure, there have been prophets of doom who have forecast the waning of the country as an important oil producer. In 1958, when the last major tax change was made, the oil companies made repeated approaches to the government that could almost be described as alarmist in depicting the dire results that the tax measures then proposed could produce.¹³

(With regard to the observations about the company reaction to the 1958 tax increases, it might also be noted that during the 1959-65 period Venezuelan production increased by about 25%, in line with the Government's general goal of moderate annual increases.¹⁴)

Finally, it is also interesting to note the role of local private industry in this oil policy debate, as reported by PIW prior to the settlement:

A slashing wide-ranging criticism of Venezuela's petroleum policy has just been presented here by Fedecamaras, a nationwide organization representing most private sectors of the country's economy....

Fedecamaras points out that Venezuela may have to lower production goals during the next decade because a drastic reduction in investment is causing a cutback in exploration....

The major premise behind the government's oil policy--that over the long term oil will become scarcer, and hence prices will improve--is false, according to Fedecamaras.

. . . The study says the government theory is that once the present unbalanced supply-demand situation is past, prices will rise substantially.

Therefore, Fedecamaras contends, the government sees every barrel of oil not produced now being worth more in the future. Consequently, the government strives for the highest possible price per barrel at present, even at the expense of losing production and markets.¹⁵

While this question of whether it is better to leave the oil in the ground than to produce it will be dealt with later, it is an ironic footnote to this episode that, at the time this Venezuelan industry group was attacking its Government for its "false" premise that in the long term oil prices will improve, the price of oil exported by Venezuela was under \$2 per barrel!¹⁶

B. Some Oil Tax Changes After October 1973

Turning to more recent cases, a dramatic example is the long tax change struggle which is still taking place in Indonesia. In January 1976 the Indonesian government announced it wanted to increase its share of the oil profit split with the companies from 65:35 in its favor to 85:15. Up until that time Indonesia had been highly regarded by the oil companies, as this early 1975 analysis by The Petroleum Economist, an industry trade journal, indicates:

One of the happier recent reversals in the oil world has been the cordial and profitable relations the industry now enjoys with Indonesia, compared to the tensions of the middle 1960s, the closing years of Sukarno's government. The credit is in general due to the western-alliance policies of President Suharto, Sukarno's successor from 1967, but more specifically to the pragmatism of Dr. Ibnu Sutowo, a leading Indonesian state oil official from 1957, and head of the state oil company Pertamina from its inception in 1968. His ambition has been to build an integrated company with full control of the nation's oil industry, employing foreign contractors, yet allowing them a good profit.¹

The quantitative background to this struggle was that Indonesia, although a member of OPEC, was obtaining only a 65:35 profit split, at a time when most other OPEC members were getting a division closer to 95:5 or more; this meant that the oil companies in Indonesia were reaping per barrel profits of \$2.25-\$2.50, compared to only 25-50 cents in the Middle East and Venezuela. (See Chapter III.)

Nevertheless, Indonesia's announcement of the proposed tax increase of about \$1 per barrel, which would still have

left the main producers there, Caltex (Standard of California and Texaco) and Standard Vacuum (Exxon and Mobil) with per barrel profits of about \$1.25-\$1.50, brought forth company warnings. PIW reported in March 1976 "the oil producing companies' contention that a sharp hike in government 'take' would force production cuts, reduce overall revenues and discourage future investment."²

Additionally, Caltex also argued that its high profits on Indonesian oil were necessary because it had to subsidize losses on its sales to refineries. And, if the producing profits were cut, it might be forced to drop its Indonesian production to as low as 700 thousand barrels per day, from its 1975 average of 831 thousand barrels per day. Hence, this would mean the tax increases would cause a net loss in oil revenues for the Indonesian government.³ Leaving aside the factual question as to whether Caltex really does lose money on its sales of crude oil, it only takes a little calculation to see that from the Indonesian Government viewpoint this loss of revenue argument is of dubious weight. It is true that if production fell by the maximum amount predicted, then with increased tax rates the government's revenue would fall, from about \$3,000 million to \$2,800 million. But, note that this temporary loss of \$200 million in government revenues would allow the country to keep in the ground some 48 million barrels of oil. With the new government take of \$11 per barrel this would mean additional potential future government revenue

of about \$520 million. Thus, while the country would forego a maximum of \$200 million in immediate income, over the longer run it would save a net amount over \$300 million.

In any event, despite Caltex's arguments, and after negotiations failed to reach agreement, in April 1976 the Indonesian government imposed the tax increase of about \$1 per barrel on Caltex and Standard Vacuum, which were working under old "contract of work" agreements. The government then turned to the smaller companies which were working on newer-type "production sharing" agreements. Here the government proposed not only to increase its share of the profit to 85%, but also to stretch out the period in which the companies were allowed to recover their costs (they had been allowed up to 40% of all oil production each year for cost recovery). The reaction of this group of companies, according to PIW, was as follows: "No matter what specific cost recovery proposals are finally enacted, the companies are pretty much unanimous that abolition of the speedy payback under the 40% ceiling will slow down exploration and could even make development of some recent discoveries uneconomic."⁴ Despite these "warnings" the Indonesian government pushed through the changes, which both slowed down the companies' cash flow and reduced their profits by an average of \$.30 to \$1.00 per barrel.⁵

It is probably too soon to tell the effect of these various changes on the prospects for development of Indonesian oil production. On one hand we do know that Caltex's warning

of a sharp drop in its oil production in 1976 failed to materialize, and its production for the year was about the same as in 1975.⁶ As for the smaller companies, their output in 1976 increased by over 30%, at a time when world oil production was basically stagnant.⁷

On the other hand, as of today, exploration drilling in Indonesia has come to a virtual standstill as the companies seek some changes in the tax laws.⁸ Whether this is a permanent drop, or simply part of the war of nerves with the Indonesian government over the tax changes, or partly due to other factors, remains to be seen.⁹ What is clear, however, is that, owing to the per barrel tax increases, Indonesia will have increased its tax take by at least \$500 million in 1976 alone. Such a sum could finance a large amount of exploration and development efforts for the country (which, for example, might be carried out with drilling companies working under direct contract for the Government). Thus, even while the tax changes may have had some negative impact on the companies' current exploration and development efforts, much of this could be offset from the increased tax revenues.

This can be seen from the fact that in 1975 total exploration and development expenditure in Indonesia was about \$1.0 billion, and before the tax dispute a similar expenditure had been planned for 1976.¹⁰ Moreover, based on data which indicate that less than one-third of the wells being drilled in Indonesia are for exploration, it would appear

that the Government's \$500 million increase in tax revenues could pay for the total exploration effort in the country.¹¹ (Since this point has more general implications, it will be examined in greater detail in Chapter IV when we discuss the alternatives open to the State of Alaska.)

Finally, Indonesia's future prospects need to be seen within the context of a general worldwide trend for governments to capture part of the windfall profits arising from OPEC's price increases. The trend began with the OPEC countries themselves, who after the sharp price increases in 1973 also sharply raised their tax rates on the companies. Typically, what had been in mid-1973 a government:company profit split of about 65:35 was raised ultimately to 95:5 or more.¹²

But, even in the industrialized countries with sizable crude oil production prospects, parallel if not so sweeping changes took place. In late 1974 and early 1975 Norway and the United Kingdom both proposed substantial "windfall profits" taxes (as well as plans for direct Governmental "participation" in the oil industry), which after some revisions were subsequently adopted. (See Chapter III.) Moreover, these proposed changes brought forth the usual warnings from the oil companies and their trade journals. For example, The Petroleum Economist in January 1975 lamented:

The spirit of OPEC, which aims at ever-increasing per-barrel revenues and maximum state participation and control, has now firmly taken hold of the governments surrounding the North Sea. The only North Sea countries as yet unaffected by this spirit are Denmark and West Germany, where petroleum exploration to date has not unlocked big offshore reserves. . . .

. . . The Dutch government had already stated in autumn 1974 its intention to seek a more than 80 per cent share in the profits of all oil and gas exploitation, by means of 40 percent participation, royalties and taxes

The enthusiasm of oil companies for exploration in the North Sea is steadily waning as government penalties for success increase.¹³

To add insult to injury, in May 1976 the Dutch Government announced new rules for future oil licenses in its sector of the North Sea. Among other things, new terms provided that the State would have the right to own 50% of all oil and gas found (up from the previous terms of 40%, for gas alone) and also would get 70% of the companies' net profits (up from 50%). Not surprisingly, "the higher taxes have already caused the chairman of the organisation of exploration companies, Nogepe, to warn of the possibility that companies may give up the idea of future operations offshore."¹⁴

Despite all these "warnings", North Sea exploration prospects appear to be quite bright. Thus, for example, a recent analysis by a British petroleum consulting firm (which was implicitly "warning" against even further increases in taxes) estimated that under current tax conditions as much new reserves would be found offshore Northwest Europe in the next 10 years as had already been found, much of it in the North Sea.¹⁵

To round out the European picture, even West Germany, which has a small domestic oil production industry (production of about 150 thousand barrels per day) in early 1976 was considering a "windfall profits" tax on its oil and gas

production.¹⁶ According to industry sources, the size of the additional tax increase was in the neighborhood of about \$114 million, or 12% of total oil and gas revenues.¹⁷ However, consideration of the Federal Government tax was put off because of strong opposition from the two principal oil producing States in West Germany which "charged the tax would threaten local oil investment and employment, state income tax "take" from oil companies, and any chance of raising state royalties."¹⁸

Interestingly, the big oil companies in Germany were divided over the tax increase issue. Exxon, a leading crude oil producer in Germany, was opposed to it. BP's German affiliate, Deutsche BP, however, which is primarily a refiner in Germany, favored the windfall profits tax, as a way of reducing the competitive advantage of the companies like Exxon which had crude production in Germany. (BP even favored coupling the new tax with a crude oil cost equalization program, analogous to that in the U.S.)¹⁹

Finally, we might note that Indonesia's tax increase apparently helped stimulate its neighbor, Malaysia, to increase its share of oil profits. The Malaysian government too had been getting a 65:35 split with its oil companies (Exxon and Royal Dutch Shell), but after negotiations and much pressure on both sides, at the end of last year the government share was increased to somewhere between 83% and 89%.²⁰ Despite this large increase in taxes, Platt's Oilgram News Service (an industry daily)

headlined its report: "Exxon, Shell optimistic on Malaysia operations under revised contracts".²¹ Platt's further noted that while Exxon now claimed it would cut its original production target from 30,000 barrels per day to 20,000 barrels per day, Shell "said its new contract (still to be signed) would provide sufficient incentives for the company to continue a high level of activity, including a reasonable level of exploration"; 50 companies are now interested in exploration.²²

By way of conclusion of this historical survey, it is not our claim that governments can at all times increase their tax shares without limit. As an example, we may take the case of New Zealand, which in October 1976 sought to impose a \$3 per barrel "energy resources tax" on crude oil production. According to Platt's, "company spokesmen say the levy, coming on top of the recent policy of letting the companies bear the brunt of all exploration costs while giving up a 51% stake to the government in the event of a find, will bring new exploration activity in New Zealand to a complete halt."²³ Following this warning, an important exploration company in New Zealand, Hunt International Petroleum, then discontinued its efforts and said it would seek \$100 million in "compensation" from the government for past exploration efforts.²⁴

Faced with this heavy pressure the Government quickly dropped its tax proposal: "Instead, the Prime Minister announced, it will work out a profits tax and discuss the basis for it with exploration firms with an eye to making it

effective next April."²⁵ Perhaps at that time it will be possible to judge whether the New Zealand Government did "over-reach" and seek an uneconomic level of taxes, or instead simply was not in a strong enough position to resist the counter-attack of the companies. That the clash between the companies and the Government, however, was fierce, can be seen from Platt's report last November:

The following exchange reflects the bitterness of the discussions that developed over the proposed levy between [Prime Minister] Muldoon and the exploration companies:

Muldoon said publicly that Hunt International Petroleum's "general approach to these questions is to the right of Ghengis Khan." John Tatum, New Zealand general manager for Hunt, which had suspended exploration, responded saying, "When you deal with Atilla The Hun, you don't send Snow White."²⁶

Finally, it may be observed that the single commonality among all the cases we have examined is that government attempts to increase oil taxes almost invariably bring forth company reactions that such tax changes will be harmful to the country. This should not be surprising, since like any small self-interest group which seeks to win public support, the oil companies' appeal must be to the interests of the general public rather than to their own primary concern--reduction of their profits. Furthermore, it must be recognized that such appeals, which are designed to influence official and public opinion to drop or modify the tax changes, are perfectly legal forms of "propaganda". On the other hand, it should also be recognized that there is nothing sacred about the content of

III. OIL COMPANY PROFITABILITY:

ALASKA AND ELSEWHERE

In assessing the impact of possible Alaskan tax changes on the oil companies' production or exploration and development plans, it is important to know not only the companies' likely profits after these tax changes, but also how these profits compare with the companies' alternatives in other places. In the "Tanzer Report", while the focus was on likely company profitability in Prudhoe Bay, a few estimates were made of oil company profits elsewhere, based on data available at that time.¹ Since a year has now passed during which there have been a number of price and tax changes in the rest of the world, and additional data has become available, in this Chapter we take an updated and expanded look at the comparative profit picture.

A. Oil Company Profitability from Prudhoe Bay: A Reassessment

To start with, we need to estimate again the likely oil company profitability in Prudhoe Bay, under different tax assumptions. To do this, we have updated the analysis of the Tanzer Report to take new data into account. Moreover, to be on the conservative side, we have adopted many of the estimates made in April 1976 by Drexel Burnham and Company (DB), a New York brokerage house which can hardly be accused of being hostile to the oil companies.¹ The specific changes are as follows.

First, we have increased the estimated investment in Prudhoe Bay, based on company estimates reported by DB. According to the DB study, Arco data now indicate an estimated total investment in Prudhoe Bay over the life of the field at about \$7.2 billion, while Sohio data indicate a lower total investment of about \$4.5-\$5.1 billion. Since our original report used a figure of about \$4.6 billion, to be on the conservative side we have now adopted the higher Arco estimates.² Second, the DB study, which also uses the higher Arco estimates, also presents estimated annual depreciation figures for the years through 1990. Since our original annual depreciation estimates were a rough average, and based on the lower investment figures, for consistency we have adopted the DB depreciation estimates.³

Third, we have used the lower production schedule estimated by DB (with peak production of 1.5 million barrels per

day versus 1.6 million barrels per day in our report).⁴ Related to this, we have adopted DB's estimated pipeline tariffs based on the lower production schedule; this increases the average tariff to about \$4.50 per barrel with peak production, versus about \$3 per barrel in our original report. Finally, we have used DB's estimated operating costs of \$.25 per barrel and marine transport costs of \$.50 per barrel (which are slightly lower than our earlier estimates).⁵

On the other hand, our treatment of the tax question has remained basically the same, and is somewhat different than that of DB. Thus DB uses a 48% federal income tax rate on net income, but does not provide data on annual company income tax credits for the years up through 1977, before Prudhoe Bay production begins.⁶ We, therefore, estimate such annual income tax credits for the 1968-77 period, as in our original report, by applying an estimated 25% discount to the annual investment base in that period.⁷ Moreover, DB assumes for its present tax case that the nominal 9.4% state income tax rate will be effectively realized by the State of Alaska. We, however, assume an effective income tax rate of only about 2.5% per year, which number is derived from data recently provided by Sohio to the State of Alaska.⁸ (Finally, to again lean on the conservative side, we accept DB's assumption that in the future the companies will no longer be allowed to "expense" intangible drilling costs.⁹)

To reassess the impact of possible State of Alaska oil

tax rate changes on company profitability, in this study we look at two arbitrarily chosen cases to compare with the present tax situation. The high case is one in which the State of Alaska levies a 50% income tax rate on oil company profits (the "50% State income tax case", as in our original report). The intermediate case is one where an income tax is levied such that the State's share of the total "oil pie" (defined as wellhead value less depreciation less operating costs), including royalty, severance and other oil field taxes, is 50% (the "50% State take" case); with royalty and severance at about 20% of wellhead value, this implies an effective State income tax rate of about one-third on oil company profits.¹⁰

Then, using the DB data and our methodology as indicated, we analyzed the most likely price case--\$13 per barrel for Alaskan crude oil delivered in Los Angeles. (The uncertain impact of a possible crude oil surplus on the U.S. West Coast was ignored, in part because the DB study concludes that it is not likely to have a significant effect on the Alaskan wellhead value.¹¹) The results were as follows.

For the present State tax structure, and with an effective federal income tax rate of 48%, the companies' DCF rate of return would be 29% per year (as compared to our original estimate of 35% per year); the division of the oil pie would be 37% for the companies, 35% for the federal government, 3% for other states and 25% for the State of Alaska (in line with our

original estimates). At the other extreme, with a 50% state income tax rate, the companies DCF return drops to 19% per year (from 25% in the original study), with the oil pie being divided one-fifth for the companies, one-fifth for the federal government, and three-fifths for the State (almost exactly the same as in our original study). For the intermediate case, where the State gets a total take of 50% of the oil pie, the companies' DCF profit rate would be 23% per year, with one-half of the pie going to the State and about one-fourth each to the companies and the federal government. (See Table III-1.)

All these data indicate that even if we use the conservative assumptions of the DB Report, including very high estimates of company investment in Prudhoe Bay and relatively low field production rates, the companies will still achieve a high profit rate on Prudhoe Bay. Moreover, even under a 50% State income tax rate, the companies should still earn a more than adequate return to cover their investment and risks, and one which as we shall see later compares favorably with their other investment opportunities.

In terms of actual money, with the present State income tax rate, the total State take would be \$14 billion from 1977 through 1995, or about \$750 million per year. Increasing the State income tax rate to 50% would increase the State take to \$35 billion, or \$1,850 million per year. In the intermediate case, with a total State take of 50%, the State would get about \$28.5 billion, or \$1,500 million per year. For the present

TABLE III-1

COMPANY PROFITABILITY AND DIVISION OF "OIL PIE":

PRUDHOE BAY, 1977-95

	(1) Current Tax Structure*	(2) State Take Equals 50% of Oil Pie	(3) State Gets 50% Income Tax
A. Division of Oil Pie \$ Billion (%)			
1. State of Alaska	14.0 (25)	28.5 (50)	34.9 (62)
2. Companies	20.9 (37)	14.3 (25)	10.9 (19)
3. Federal Government	19.9 (35)	13.7 (24)	10.6 (19)
4. Other States*	1.5 (3)	-- (-)	-- (-)
5. Total**	56.3(100)	56.5 (99)	56.4(100)
B. Division of Oil Pie (\$ per Barrel)			
1. State of Alaska	1.80	3.66	4.48
2. Companies	2.68	1.84	1.40
3. Federal Government	2.55	1.76	1.36
4. Other States	.19	--	--
5. Total	7.22	7.25	7.24
C. Company DCF Profit Rate (Per Year)			
	29%	23%	19%

Bases: Combination of DB and "Tanzer Report" data and assumptions--see text.

* State of Alaska current take based on royalty and severance equal 20% of wellhead value, plus effective income tax equal 2.5%; other states assumed effective income tax rate equal 3.5% now and zero in two increased state tax cases.

** Totals are not equal because of rounding.

tax rate case the companies would get after-tax profits of \$21 billion, or \$1,100 million per year; for the 50% income tax case the companies would get \$11 billion or \$575 million per year; and for the intermediate 50% State take case the companies would get \$14 billion or \$750 million per year.

Finally, we may note the following per barrel figures for company profits in each of the three State income tax cases, as they will be useful for comparison with the companies' opportunities in other countries: present State tax rate, \$2.70; 50% income tax case, \$1.40; 50% State take case, \$1.85.

B. Oil Company Profitability Potential Outside Alaska

Turning now to the alternative possible sources of crude oil for the oil companies, in this section we will examine the profitability in the principal areas serving the U.S. market. Clearly the most important potential source of future crude oil for the U.S. is the Middle Eastern and North African countries. These OPEC members have about 60% of the world's oil reserves, and in recent years have been the fastest growing source of U.S. oil imports, increasing their share from 17% in 1970 to 39% in 1975 (during a period when U.S. crude imports increased from 1.3 million barrels per day to 4.1 million barrels per day, or threefold).¹ And just as clearly, the profitability potential for the oil companies from such oil countries is quite limited. (See Table III-2.)

Basically, all of the Middle Eastern and North African countries have either taken, or are in the process of taking, 100% ownership of their oil fields. (Where the companies still have an equity interest in production, the normal royalty is 20% and the income tax rate is 85%.) Hence, the principal profit possibilities for the companies now are as providers of technical skills and marketing outlets, for service fees. In most of these countries, the allowed fee is in the neighborhood of \$.15 to \$.25 per barrel. For example, in Qatar, the companies get about 15 cents per barrel, in Kuwait \$.19 per barrel, and in the most important country of all, Saudi Arabia, they

TABLE III-2

COMPANY COSTS, PROFITABILITY AND DIVISION OF OIL PIE
IN MAJOR PRODUCING AREAS (ESTIMATED)

	(1) Price of Crude Oil (Wellhead) \$ per Barrel	(2) Capital Plus Oper- ating Costs, \$ per Barrel	(3) =(1)-(2) Oil Pie (\$ per Barrel)	(4) Company Profits (or Fee) \$ per Barrel	(5) Company: Government Division of Oil Pie (% Shares)
Middle East and North Africa	12.50 to 13.00	.25 to .50	12.25 to 12.50	.15 to .25	2:98
Nigeria	14.00	1.00	13.00	.30	2:98
Venezuela	13.00	1.00**	12.00	.20	2:98
Indonesia	13.00	1.00**	12.00	1.00-1.50	12:88
North Sea	12.00	2.50	9.50	3.50	37:63
Canada	13.00***	2.00	11.00	1.25	11:89

Memo: Prudhoe Bay

(a) Present Tax Structure	8.25	1.00	7.25	2.70	37:63
(b) 50% State Take	8.25	1.00	7.25	1.85	26:74
(c) 50% State Income Tax	8.25	1.00	7.25	1.40	19:81

Note: Data are approximate current estimates; for sources see text and footnotes.

* Capital costs normally predominate.

** Assumed for calculation purposes.

*** "Wellhead Value", based on controlled wellhead price plus export tax.

expect about \$.21 per barrel.² With crude oil selling at about \$12-\$13 per barrel, and investment costs in this area estimated at about \$.25-\$.50 per barrel, this means that the oil pie here is split about 2% for the companies and 98% for the governments.

The companies' profit potential in the other OPEC countries appears equally limited. In Nigeria, which accounts for 3% of the world reserves but 18% of U.S. crude oil imports, the companies' profit margins in 1976 were reduced to 30 cents per barrel (from 50 cents previously).³ With prices at about \$14 per barrel and production costs of \$1 per barrel this also implies a profit split of about 2% for the companies and 98% for the Nigerian government. Similarly, in Venezuela, which has 2% of the world's reserves but supplies 10% of U.S. crude imports, the wholly nationalized oil industry allows the oil companies a technical and marketing fee of about 20 cents per barrel.⁴

Finally, even in Indonesia, the other principal OPEC country supplying the U.S. market (9% of U.S. imports and 2% of world reserves), profit margins are now estimated at about \$1.00-\$1.50 per barrel.⁵ This is half of those in Prudhoe Bay, under the present Alaska tax structure, and in line with margins which would prevail under a 50% State income tax. Moreover, the companies' share of the oil pie in Indonesia, while the most favorable in all the OPEC countries, is still only about 12%, compared to 39% in Alaska under the present tax structure and 19% with a 50% State income tax.⁶

Coming closer to home, Canada is the other principal supplier of crude oil for the U.S. market, accounting for 15% of the total. However, Canada has only 1% of the world's reserves, and Eastern Canada is an importer of crude oil. Hence the Canadian Government has announced a policy of ending Western Canadian exports to the U.S. in the next few years.⁷ In addition, the profits for the oil companies in Canada, while higher than in most OPEC countries, are less than in Alaska, even under the highest tax case we have discussed. Specifically, in Canada, based on data provided by the oil companies, their profit margins appear now to be about \$1.25 per barrel.⁸ With the price of Canadian crude oil in the U.S. market about \$14 per barrel (consisting of a price controlled wellhead value of close to \$10 and an export tax of about \$4), and exploration and production costs about \$2 per barrel, the division of the oil pie is about 10%-12% for the companies and 88%-90% - for the federal and provincial governments of Canada.⁹

Because Canada has a federal system analagous to that of the U.S., it is worth examining the Canadian profit picture in a little more detail. As of January 1, 1976, when the wellhead price for Alberta crude oil was price controlled at \$8 per barrel, there was a Canadian federal government export tax of \$4.60 per barrel added on, to roughly equalize the export price with the price of crude oil in the U.S. markets. Of this \$12.60 per barrel received by Canada, exploration costs were about \$1.35 per barrel and operating costs \$.50 per barrel,

which left an oil pie of \$10.75 per barrel. Of this the companies had net profits of \$.84, provincial taxes were \$3.74, and the federal income tax was \$1.57. Thus, on a percentage basis, the companies got 8% of the oil pie, the provincial governments 35%, and the federal government 57% (including the export tax, which was largely redistributed to Eastern Canada as an oil import subsidy).¹⁰

As of January 1, 1977, the wellhead price was raised to \$9.75, while the export tax was dropped to \$3.25 (which changes do not yet reflect the January 1 increases in OPEC prices). According to two Canadian oil companies (Imperial, an Exxon affiliate, and Ranger), of the wellhead price increase of \$1.75 per barrel, their profits increased by about \$.43 per barrel; adding this to the \$.84 per barrel reported previously, this would imply company profits of \$1.27 per barrel. Thus, it would appear that the companies' share of the oil pie now would be about 11%. The provinces on average received an additional \$.77 per barrel in this period, bringing their take to \$4.51, for about 41% of the oil pie. This leaves an estimated 48% for the federal government in Canada.¹¹

By way of footnote, while the Canadian federal and provincial governments take such a relatively large share of the oil pie, compared to the situation in Alaska, the pace of exploration drilling in Western Canada set new records last year.¹²

Finally, we might take further note of the other

principal foreign oil prospect, offshore Northwest Europe. Although most of the expected peak production of 5.5 million barrels per day by 1990 is likely to go to Europe, and will not be available for the U.S. market, still it is worth examining the companies' likely profitability here.¹³

Towards this goal, we have the benefit of a recent "composite" model of the area (called here the "North Sea")-- an average for 7 fields discovered by the end of 1975, and assumed similar sized discoveries beyond 1975.¹⁴ This model, which is worked out annually for the 1971-2012 period, shows an average profitability for the oil companies of about \$3.50 per barrel, with their share of the oil pie being about 37%. (The model uses the United Kingdom's tax rates since the differences between it and the Norwegian Government are relatively minor.) Based on the per barrel numbers, superficially it would appear that the North Sea is a better profit prospect for the companies than Prudhoe Bay, even under current State income tax rates, and much better if the State of Alaska increases its rates substantially.

The fallacy in this, however, is that investment costs in the North Sea are much higher than in Alaska. Thus, over the life of the model, the average investment cost in the North Sea is estimated at \$1.85 per barrel, compared to a maximum \$.75 per barrel for Prudhoe Bay (excluding, of course, the pipeline, which as DB notes: "represents a distinct, and very important, profit (as well as cost) center in the

integrated economics of North Slope oil."¹⁵ As a result, the all important DCF rate of return on North Sea investment is projected to be lower than in Alaska, rather than higher. Thus, for the composite North Sea model, the DCF profit rate for the North Sea is estimated to be about 19% per year. This compares unfavorably with the 29% per year DCF return we estimate the companies will make from Prudhoe Bay under the present State tax structure, and is the same rate as the companies would earn from Prudhoe Bay with a 50% State income tax rate in Alaska.

Finally, in analyzing the companies' alternatives to exploration and production in Alaska, one additional factor needs to be considered. Namely, for the oil companies, security of supply is becoming of increasing importance, and the U.S. clearly is the companies' most secure supply source. In the OPEC countries, the clear trend is for the governments to want the actual oil, rather than its market value in cash, and either use this oil internally or export it themselves. Even in the North Sea, as we have seen, the governments are taking participation in the new fields.

Since the oil companies need an assured supply of crude oil to reduce the risk on their investments in refining, marketing and transport facilities, it is clear that such a secure supply has more value to the companies than is measured simply by its market price. (Evidence for this is the bids for Alaskan royalty oil at a premium above market price.)

Moreover, in the past, when there was a glut of crude oil but the companies' per barrel crude oil profits were still quite high, there was a tendency to build refineries and marketing facilities which made little or no profit, but would serve as a sure outlet for the profitable crude. Today, with the world entering an era of crude oil scarcity, but low per barrel profits for the companies, investment in new refining and market facilities will have to earn much higher profits to be justified. The corollary of this is that for a company which has existing refining and marketing facilities, an assured supply of crude oil can greatly increase the value of these facilities. (Conversely, the inability to obtain crude oil can greatly reduce the value of such facilities.)

Furthermore, if OPEC's new conceptual approach to crude oil pricing is successful in the future, such oil will have a much higher price. The basic new idea is that oil exporting countries should value their crude oil not just at the price which makes it competitive with other energy sources, but they should also add on premiums. One premium would reflect the fact that, for the country, using up the crude oil as an energy source now will make it unavailable in the future for a more valuable use, as a petrochemical feedstock. On top of this, an additional premium should be added on to reflect the fact that petrochemicals are a basic element in modern industrialization, so a country's loss of the opportunity to make petrochemicals means a loss of industrialization opportunities.¹⁶ Thus, the

real value to a country of crude oil might not just be \$15-\$20 per barrel but, e.g., \$30-\$40 per barrel (leaving aside the effects of future inflation).

In the final analysis, the fact that crude oil in a world of long run scarcity may be far more valuable than is measured by its present market price is of considerable significance to the State of Alaska. Its most obvious significance has already been discussed--namely, that it makes Alaska as a secure supply source an especially desirable place to explore for crude oil. Its less obvious significance, however, is that it raises important questions as to what is the best approach for the State of Alaska in terms of the pace and type of development of its crude oil resources. These questions, however, are more appropriately discussed in the following chapter on the benefits and costs of increased oil taxation in Alaska. From the analysis of the present chapter, however, we can conclude that substantial increased State oil taxation is not likely to end the attractiveness of Alaska to the oil companies as a place for additional exploration, development and production.

IV. CONCLUSIONS: BENEFITS AND COSTS TO ALASKA FROM INCREASED OIL TAXATION

In the preceding chapters, we have seen that there has been a long history around the world of increases in government oil tax rates, which the oil companies have typically claimed would hurt exploration or production. We have further seen that these tax increases, which accelerated in the post-1973 period, have been large enough that even the maximum tax increase analyzed here for Alaska would be unlikely to deter the companies from future exploration and production in Alaska.

Since, however, there can be no absolute certainty about the question of the impact of increased taxation on the oil companies' behavior, in this final chapter we seek to answer the following question: "Assuming that the increased State taxation would reduce future exploration and development in Alaska, is it or is it not worthwhile to have the increased taxation?" To do this, we need to first estimate both the benefits to Alaska of the increased taxation, as well as the possible losses from reduced exploration and development, and compare the two. And second, we need to see if there are ways by which the State could use some of its benefits to help reduce any such losses.

The benefits to Alaska of increased taxation are fairly obvious. The initial benefit, of course, is the increased State revenues. In the two tax change cases we have considered, these amount to between \$15 billion and \$21 billion over the life of the main Prudhoe Bay formation alone, or about \$750 million to \$1,100 million per year. To put these huge numbers into some more recognizable perspective, the increased State tax revenues over the life of the main Prudhoe Bay formation would be between \$40 thousand and \$60 thousand for every man, woman, and child now living in Alaska. Moreover, there would be substantial increased tax revenues also from the two lesser formations in Prudhoe Bay, which have already been explored and would likely be developed even at the highest tax rate.

A secondary benefit of increased State oil tax revenues is that with proper planning these could be used to promote Alaska's economic development, both within and outside the petroleum sector, and thus have a "multiplier" effect. In contrast, if the increased State tax revenues are foregone, most of the money will flow out of the state as oil company profits and federal corporate income taxes. Particularly since the major oil companies in Prudhoe Bay already have more Alaskan crude oil than they can easily handle, they have even less incentive than other oil companies to reinvest in new exploration and development in Alaska. (Thus, for example, Arco has used part of its expected increased cash flow to buy a major copper producer, Anaconda, into which it expects to pour much additional investment.¹)

If we turn now to the costs of increased State oil taxation, the basic one claimed is that there will be reduced exploration and development investments in Alaska. In assessing this claim, it is necessary to distinguish between investment for exploration and investment for development. As we noted in our original report, exploration is a risky business which requires a high profit rate to cover the risk, but development is relatively safe and does not require the same high rate.² Moreover, the bulk of oil money for exploration and development is for the latter category.

Specifically, in the whole United States, in the 1973-75 period only about one-fourth of all wells drilled were exploratory, while the rest were development wells.³ The average annual amount spent on exploration and development (including lease payments) in this period was about \$10 billion; of this amount about \$1 billion was spent on geological and geophysical expenses and lease rentals.⁴ Thus, if as a rough assumption we assume that the division of exploration and development expenses is proportional to the number of wells drilled, and we add the geological and geophysical expenses to estimated exploration drilling costs, we find the total exploration effort to be about \$3.3 billion, or only one-third of the total exploration and development effort in the U.S.

For reasons to be discussed below, exploration is the most crucial part of the combined exploration and development effort, and the part which theoretically might be most hurt by

increased tax rates in Alaska. How much it might be hurt is impossible to say, although as discussed in the previous Chapter we do not think cutbacks by the companies would be very great. But, even if we are wrong, in this connection it is significant to note that the annual tax revenues on Prudhoe Bay foregone by the State by keeping its present tax structure, as compared to a structure with a 50% tax rate on the companies' profits, would amount to about \$1,100 billion per year, or about one-third of all of the exploration effort carried out by the companies in the whole United States. Put in this context, it would appear that any reasonably foreseeable amount of oil company exploration in Alaska which was "lost" because of the increased State tax rate could easily be "financed" by the State itself.

Thus, one possibility would be for the State to replace the "lost" exploration services by directly contracting with the numerous independent firms which specialize in this work and do much of the exploration effort for the major oil companies; this is an approach successfully followed by a number of Third World governments.⁵ Another possibility would be for the State to enter into a joint venture agreement with one or more companies to carry out the exploration effort. This approach has also been used successfully by other governments; the relationship may vary from one where the government pays its share of the exploration effort to one where the government gets its share on a "carried interest" basis, meaning that it pays only if the exploration effort is successful. (This latter approach

is used, for example, by the Norwegian government with its new North Sea licenses.⁶⁾

As for the much larger oil development effort, once successful exploration is carried out, funding for this in a world of oil scarcity should present no serious problems. If the oil is found by the State itself, through service contractors, it could either use its own money to develop the field, or borrow either from the capital markets or from independent refining companies which would be eager to obtain an assured supply of crude oil. If the oil were found by a joint venture, then normally the State's co-partners would use the oil themselves or could market it.

Ultimately, the question of how much development takes place will largely depend on the expected profit rates. Here we might note that a 15% DCF rate of return on development expenditures should be enough incentive for oil companies to develop any fields found. By way of indirect evidence, the firm of La Rue, Moore, and Schafer, Texas petroleum consultants, helped prepare testimony for the U.S. Congress which used a 15% DCF rate of return as the level necessary for exploration and development of new oil in the U.S.⁷ Again, in the previously discussed model estimating the likely new production from the North Sea, the British petroleum consulting firm of Gaffney, Cline & Associates uses a 15% DCF rate of return as its minimum for field development.⁸

In this connection, it might also be noted that if the

State has an equity participation in the exploration and development efforts, more development may take place than if the exploration and development efforts were left solely to the oil companies. This is because the State has a lower cost of capital and hence does not need as high a rate of return as the oil companies. Thus, for example, if the State seeks a 10% per year return on its investment, and a marginal field is found which would yield 12% on investments, the field would not be developed by oil companies seeking a 15% return.

Finally, our overall conclusion on this question of a comparison of the benefits and costs of substantially increased State oil tax rates can be summarized as follows. The benefits are clear and very large, while the costs are unclear and likely to be much less sizable. Given the history and current situation of the international oil industry, the cries that the State will ruin itself by increased oil taxation need to be discounted at a very high rate indeed. Thus, in our view the previously cited warning of the Vice President of Sohio that the State must beware of hurting the "little red hen" oil industry through increased taxation may cite the wrong literary reference. Indeed, it seems as if the little red hen may rather be a modern version of "Henny Penny", in the old fable "Chicken Little", who continues to cry, "The sky is falling" because an acorn has fallen!

Exploration and Development in Alaska: A Final Word

Having completed our assigned analysis, we would like to conclude with some observations about broader economic questions raised by the Study, which ought to be considered in developing an overall State oil policy. One key question is the following: "Even if increased State oil tax rates did slow the pace of oil exploration and development, is that necessarily bad?"

Thus, especially if the State keeps its oil tax rates low in order to maximize exploration and development, since most of the additional oil pie is also likely to leave the State, will not Alaska be recklessly wasting its precious non-renewable resources without adequate provision for future generations? After all, it must always be remembered that oil is not lumber, and a barrel extracted is a barrel gone forever. This is particularly significant if, as seems likely, over the long run the value of oil will be continually increasing.

Given these considerations, in our own view, the following would be a sensible overall strategy for the State of Alaska, in terms of the best interest of its people. First, the State should substantially raise oil taxes now, even if it cuts future exploration and development somewhat. Second, the State should temporarily cease leasing on its lands, until it effectively learns the oil business and how to operate in it. Third, and related, the State should invest some of its increased

tax money for a complete exploratory survey of its lands; only with comprehensive geophysical and geological data can the State have some idea of its potential resources (oil or otherwise). Fourth, given such a preliminary inventory of potential, the State should then directly contract for further exploration, or work with companies on a joint venture basis; even if the State decided to continue more traditional lease arrangements, however, at least it would then be in a better position to obtain a fairer share of the treasures which may lie on State lands.

The question of what position to take toward rapid exploitation of non-renewable resources is not an easy one. While there is a tendency to always equate rapid exploitation with progress, it should perhaps be a word of warning that some which have gone down that road in the past are less happy with it now. Thus, for example, the Premier of Alberta, Canada's leading oil producing province, last year urged a "go slow" policy on oil and gas development:

[Premier] Laugheed said squandering the province's resources now could leave "the dreadful legacy of turning Alberta into a have-not province."

Reviewing the rapid development since his government was elected in 1971, the Premier said, "if I had it to do over again, I would try to spread out the time frame of some of our decision-making in the first term."⁹

Again, the Norwegian government has taken the position that it does not want rapid exploration because if it is known that more oil reserves exist there, enormous pressure will be

exerted to rapidly develop these reserves, even if it is not good for the country.¹⁰

But, in the final analysis, these questions are part of the most basic question of the kind of life the people of a state or country seek. Yet, for the people to decide they must be informed--not only on the pros and cons of each individual question and policy, but also on the interrelationships between them. It is our hope that the present study will be a useful link in a chain of information and analysis that will help the State of Alaska, which is at a crucial crossroads in its history, to choose a fruitful path in the coming years.

FOOTNOTES

I.

1. The Anchorage Times, January 27, 1976, p. 6.
2. Ibid., October 26, 1976, p. 11.

II.A

1. Based on data from The Times (London, March 17, 1951, p. 4, and Keesing's Contemporary Archives, March 31-April 7, 1951 (p. 11367)).
2. Ibid.
3. Keesing's Contemporary Archives, May 5-12, 1951, p. 11450.
4. Henry S. Grady, "Tensions in Iran", Vital Speeches of The Day, October 15, 1951-October 1, 1952, p. 373.
5. See David Wise and Thomas B. Ross, The Invisible Government (New York: Random House, 1964), p. 110.
6. See Michael Tanzer, The Political Economy of International Oil and The Undeveloped Countries (Boston: Beacon Press, 1969), p. 326.
7. Production data from United Nations, World Energy Supplies: 1950-1974 (New York: United Nations, 1975), p. 70; hereafter cited as WES.
8. Petroleum Intelligence Weekly (PIW), June 13, 1966, p. 2.
9. PIW, September 19, 1966, p. 6.
10. Calculated from data in PIW, October 17, 1966, p. 1.

11. Ibid., p. 2.
12. WES, op. cit., p. 70.
13. PIW, December 12, 1966, p. 6.
14. WES, op. cit., p. 70.
15. PIW, June 13, 1966, p. 5.
16. Calculated from data in PIW, September 19, 1966, p. 6, and October 17, 1966, p. 1, which imply average prices of about \$1.92 per barrel, F.O.B. Venezuela.

II.B

1. The Petroleum Economist (PE), March 1975, p. 99.
2. PIW, March 1, 1976, p. 1.
3. Ibid., p. 2.
4. PIW, June 28, 1976, pp. 3-4.
5. Platt's Oilgram News Service (Platt's), September 22, 1976, p. 3.
6. Based on data for January through November, as reported in PIW, December 20, 1976, p. 10.
7. Ibid.
8. Far Eastern Economic Review (FEER), January 28, 1977, pp. 38-9.
9. One unsettling factor was the U.S. Treasury ruling in early 1976 that oil tax payments paid to countries like Indonesia might in the future be treated as royalties and not as income tax payments, and hence the U.S. income tax liability of the companies would rise.
10. World Oil, August 15, 1976, p. 190.

11. Based on data in Ibid., pp. 190-4, and American Petroleum Institute, Basic Petroleum Data Book, Section III, Tables 11a and 12a (April 1976); hereafter cited as API Data Book.
12. The mid-1973 profit split is from data in the Economist (London), July 7, 1973, Survey, pp. 16, 19.
13. PE, January 1975, p. 4.
14. PE, May 1976, p. 177.
15. PE, December 1976, pp. 458-60.
16. PIW, February 2, 1976, p. 2.
17. Ibid.
18. PIW, February 9, 1976, p. 3.
19. PIW, February 2, 1976, p. 2.
20. PIW, December 20, 1976, p. 11.
21. Platt's, November 24, 1976, p. 2.
22. Ibid., p. 3, and PIW, January 10, 1977, p. 11.
23. Platt's, October 13, 1976, p. 1.
24. Platt's, November 1, 1976, p. 2.
25. PIW, November 15, 1976, p. 8.
26. Platt's, November 9, 1976, p. 4.

III

1. Tanzer Economic Associates, Inc. "Alaska's Prudhoe Bay Oil: Profitability and Taxation Potential (A Report to the Alaska State Legislature, January 9, 1976), pp. 75-6; hereafter cited as Tanzer Report.

III.A

1. Drexel Burnham & Co., Inc., "The North Slope: Paradise Lost?" (April 27, 1976; hereafter cited as DB.
2. DB, pp. I-11 to I-14.
3. Ibid., Appendix Table II-E.
4. Ibid., p. IV-3. The DB "Reserves Constraint" case was adapted, with interpolated and extrapolated production figures as follows (millions barrels per day): July-December, 1977, 6; 1978-85, 1.5; 1986-90, linear interpolation to 1990=1.045; 1991-95, 15% per year decline.
5. Ibid., Appendix Tables II-E, II-G.
6. See DB, p. IV-21 for discussion of federal tax treatment.
7. For a discussion of the reasons see the Tanzer Report, pp. 38-40.
8. At the same time, we assume the companies will pay an additional 3.5% effective income tax rate to other state - governments in the U.S.: these implicit effective income tax rates for State of Alaska and others are derived from data in "Sohio Submission One", dated October 28, 1976.
9. DB, IV-21.
10. Assuming operating and depreciations cost of about \$1.00 per barrel.
11. DB states "If prices of domestic crude are constrained below import parity, as we deem likely, then the movement of Prudhoe Bay into the more distant markets would not

likely result in a lower netback than if Alaskan oil were marketed solely on the West Coast." (p. IV-27).

III.B

1. Calculated from API Data Book, Section II, Table 3, and Section IX, Tables 4a and 4b.
2. Data from PIW: October 18, 1976, pp. 3-4; March 29, 1976, p. 2; November 1, 1976, p. 3.
3. PIW, October 18, 1976, p. 6.
4. Ibid., p. 3.
5. PIW, January 1, 1977, p. 7; FEER, January 28, 1977, pp. 38-9.
6. Indonesian data from PIW, January 10, 1977, p. 7.
7. Canada plans to end all crude exports to the U.S. by 1981 (PE, August, 1976, p. 297).
8. Based on data from Oil and Gas Journal (OGJ), April 26, 1976, p. 66 and PE, August 1976, p. 297.
9. Ibid.
10. OGJ, April 26, 1976, p. 66.
11. PE, August 1976, p. 297.
12. Platt's, August 13, 1976, p. 3; data for first seven months of 1976.
13. Peak production estimated by model of Gaffney, Cline & Associates, U.K. petroleum consultants, as reported in PE, December 1976, p. 458.
14. Ibid., pp. 458-60; the model covers about 40 billion barrels in reserves, of which 20 billion have been already

proven in the North Sea itself and a "significant proportion" of the additional reserves are also expected to come from extension to these existing fields.

15. DB., p. IV-6.
16. The basic approach is that of the Organization of Arab Petroleum Exporting Countries (Platt's, Nov. 8, 1976, p. 3).

IV

1. See Forbes, July 15, 1976, pp. 67, 69.
2. Tanzer Report, pp. 78-9.
3. API, Section III, Table 2.
4. Based on data in API, Section V, Table 9 and Chase Manhattan Bank, Financial Analysis of a Group of Petroleum Companies: 1975.
5. For example, see the Tanzer Report, p. 88.
6. On Norway, see PE, March 1976, p. 105.
7. Testimony of Robert R. Nathan, April 28, 1975, reprinted in "Gas Production and Supplies" (Joint Hearings before the U.S. Senate Committees on Commerce and Government Operations), Serial No. 94-44 (Washington: U.S. Government Printing Office, 1975), p. 235, and criticised on pp. 241-51.
8. PE, December 1976, p. 459.
9. Platt's, April 7, 1976, p. 2.
10. "Once discoveries are made, technical, economic and political reasons make it difficult to limit their

exploitation. Exploration activities should therefore be regulated by the size of finds already made.

"Desiring a long-term exploitation of resources and on the basis of its overall assessment of the social implications, the Government has come to the conclusion that Norway should maintain a moderate rate of extraction of the petroleum resources." (Royal Norwegian Ministry of Finance, Parliamentary Report No. 25 (1973-74): Petroleum Industry in Norwegian Society, p. 6).