

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1486 SCOM 55: JNT. SPEC. COMM. ON STATE TAX POLICY, 1986-1987 1286

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

[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] 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

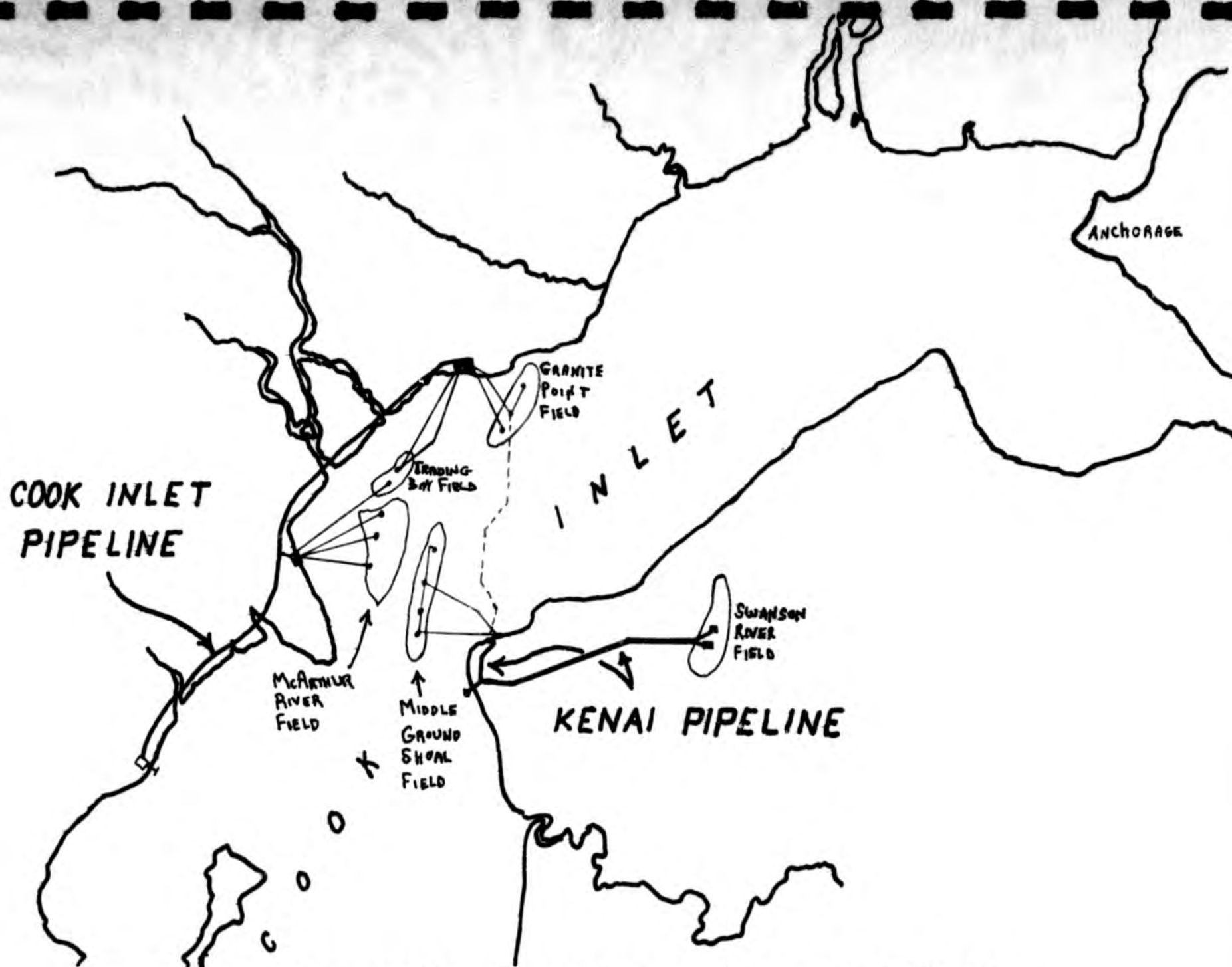


Figure I-1 Cook Inlet Area Oil Fields and Oil Pipelines

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

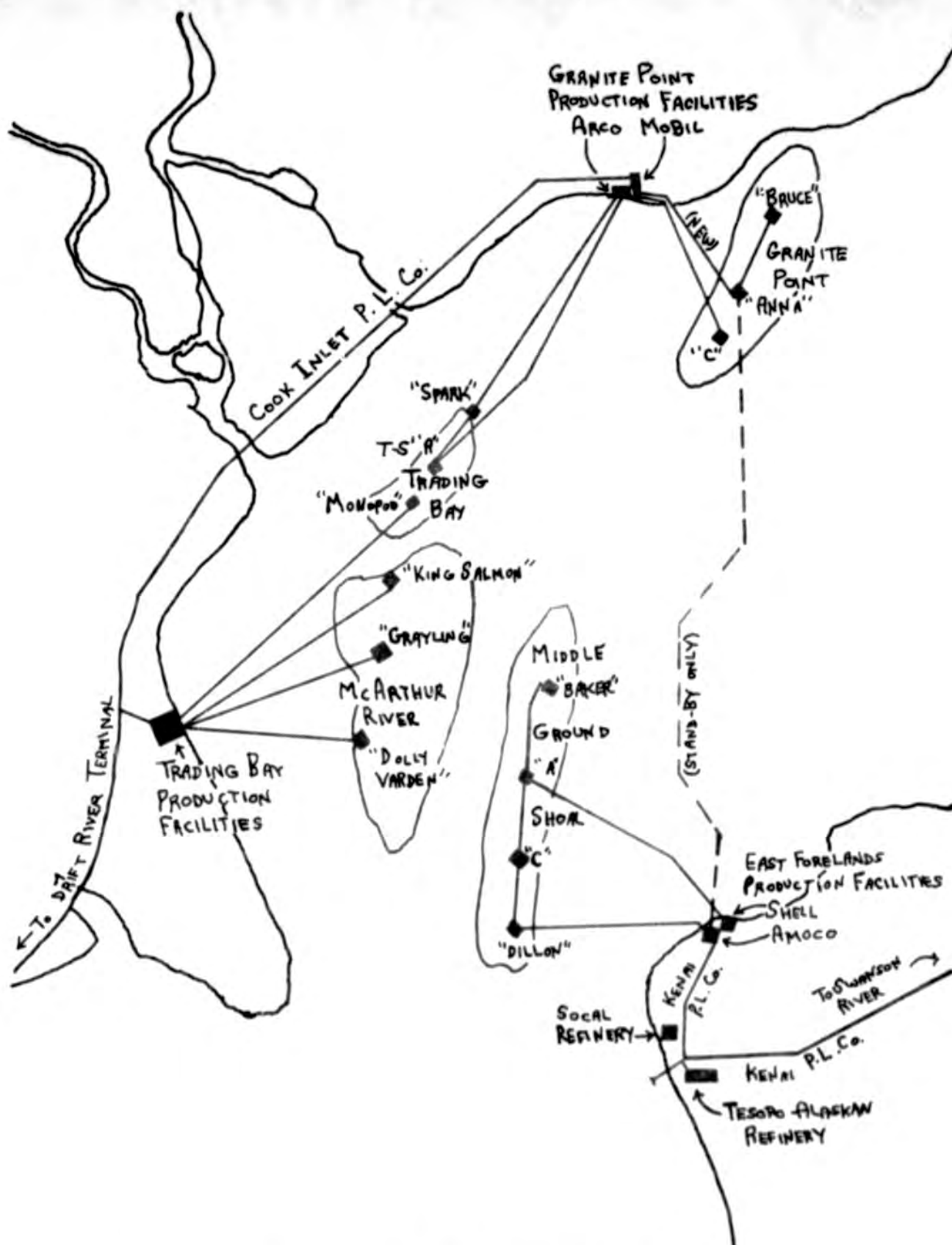


Figure I-2 Cook Inlet Offshore Oil Operations

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

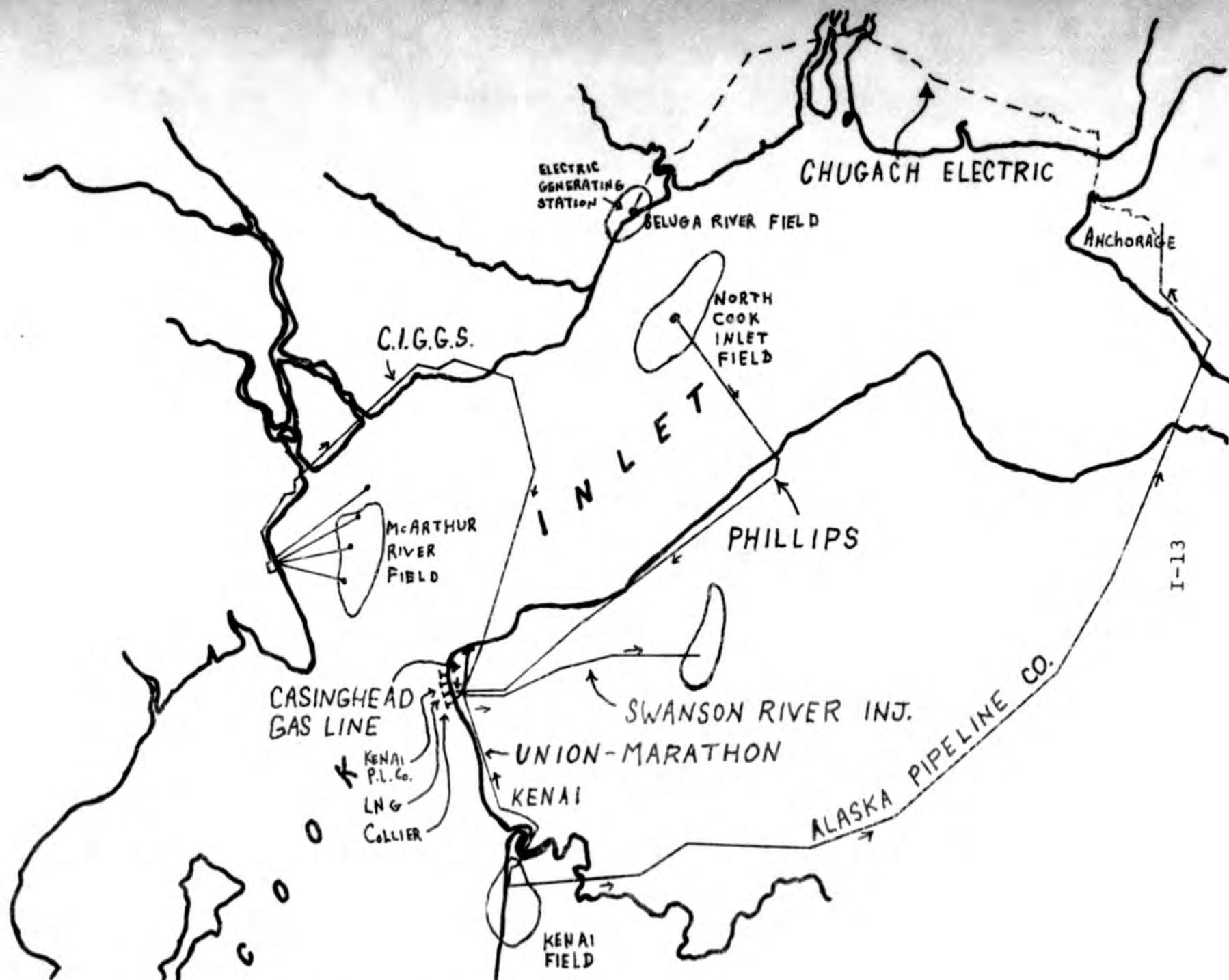


Figure I-3 Cook Inlet Gas Fields and Gas Pipelines

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

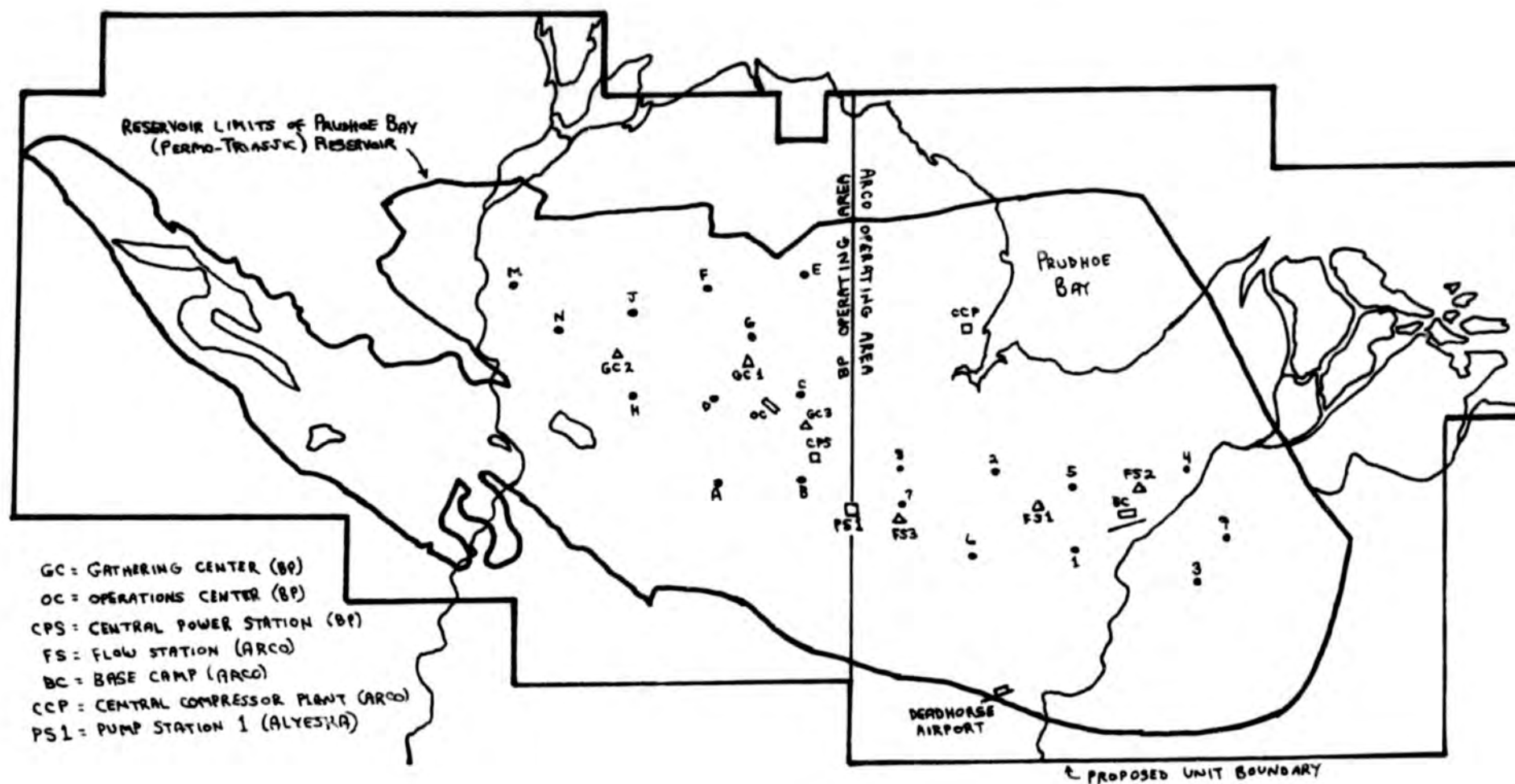


Figure I-4 Prudhoe Bay Field

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		(2) Net Int. Production		(3) Net Int. Income	(4) Total Expense	(5) Net Income	(6) Discount Factor	(7) Present Worth
	Oil 1,000,000 B	Gas BCF	Oil 1,000,000 B	Gas BCF	\$1,000,000	\$1,000,000	\$1,000,000		\$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.