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fields and future development (see Oil and Gas Journal, April 7, 1980, p. 39). However, the Petroleum Economist reported in June 1980, "Despite the recent increase in petroleum revenue tax to 70%, it seems likely that all but the smallest of the possible fields will move towards development over the coming years.... Prospects this year, however, are for a good increase in drilling activity... Availability of rigs could prove to be the limiting factor on exploration this year"(Petroleum Economist, June 1980, p. 234-235).

18. In early 1981, a supplementary petroleum revenue tax was introduced along with reductions in deductable allowances, which increased the government take on production from new fields to 85 to 90% (Oil and Gas Journal, March 23, 1981, p. 49). Again, dire warnings were heard from the oil industry. One company, Occidental Petroleum, said it was postponing development plans for the North Claymore field (a marginal, 50 million barrel field). British Petroleum attacked the tax, stating that "although BP hasn't followed other companies in cutting production because of the tax changes, that doesn't mean we won't" (Wall Street Journal, April 3, 1981, p. 24). Although at this time it is very difficult to judge the effect of the most recent tax on oil exploration and development in the U.K. North Sea, the latest round of awards for offshore oil concessions indicates continued interest on the

part of the oil industry. The World Business Weekly reported on March 20, 1981, "Judging by the outcome so far, the new policy seems to be a resounding success." Petroleum Intelligence Weekly reported in December 1980, regarding the new tax, "But, producers complain this is the U.K.'s eighth North Sea tax increase in just 18 months. They claim all the higher 1980 prices have been eroded away in "real terms" by inflation and appreciation of the pound against the dollar... But Wood, Mackenzie notes that Norway's tax terms are still more onerous than the proposed UK structure -- and activity continues to florish there" (PIW, December 8, 1980, p. 8).

19. Finally, it may be noted that British Petroleum gains almost all of its revenues, profits and production from either the North Sea or the North Slope. Given the nationalization of its fields in Nigeria and Iran, and its declining production elsewhere in the world, British Petroleum has little left outside of these areas. It may be useful to look at British Petroleum's biggest field in the North Sea, the 500,000 b/d Forties field, of which it owns 96%, and which is the most profitable in the whole North Sea. The total government tax take over the life of the Forties field has been estimated to be 88%. With this tax take and the high North Sea production costs, BP will get an estimated constant dollar DCF profit rate of 28.4% (Petroleum Economist,

April 1981, p. 147), or a current dollar profit rate of roughly 40%. In Alaska, on the other hand, where the government tax take is only about 67%, the company will get a much higher profit rate, of between 60 and 70%.

20. Canada

Canada has been, in recent years, the number two nation in the world in terms of exploration activity (after the United States). Changes in government policy, announced in late 1980, appear to have reduced at least temporarily, the amount of exploration activity. From March 31, 1980 to March 30, 1981, the number of active drill rigs has declined nearly 40% and many U.S. companies have reduced exploration and development budgets. Probably the greatest cause of this decline in investment has been the government's announced objective to reduce control and ownership of the Canadian oil industry by foreign companies from the present 72% to less than 50%. Included in these policy changes are:

(1) The state company, Petro-Canada, will automatically be given a 25% net carried interest, without compensation, on every lease right for oil or gas on federal land.

(2) Depletion allowances (currently 33-1/3%) will be phased out and replaced by direct government incentives in the form of subsidies. The incentive system will be constructed in such a way to give an important advantage to Canadian-owned companies.

(3) An additional 8% federal tax on gross oil and gas income will be instituted. This tax will be subject to upward adjustment and is not deductable. Analysts have predicted that the tax will result in a 25% reduction in net profits to the companies (Petroleum Economist, December 1980, p. 511). Predictions have been made that the overall energy plan will cut the industry's cash flow by 50% (Platt's Oilgram News, November 20, 1980, p. 5).

(4) Leases to explore federal land could be given only to applicants that are at least 50% Canadian owned.

(5) An as of yet undetermined percentage of goods and services that are used on federal land exploration and drilling will have to be purchased from Canadian sources.

Another investment restraint is Canada's federal price controls which limit the price of oil produced in Canada to $17.75 per barrel, or about 50% of the market price.

21. Before the new energy policy, the profitability per barrel in Canada has been reported as ranging between $2 per barrel (by Petroleum Analysis Ltd. in the Autumn, 1980, OPEC Review) to $6.20 per barrel (by Shell for the year 1980 in the Oil and Gas Journal, March 30, 1981, p. 47). With

the additional tax of 8% per year, the company's profitability per barrel would be reduced to roughly $1.50 per barrel to $5.40 per barrel. Taking Canadian heavy oil, with a market price of $33.50 per barrel, the total government take would range between 85 and 95%.

22. Indonesia

Indonesia is of special interest when comparing the investment climate of Alaska to other countries since it is the source of most of the oil imports landed on the West Coast (some 300,000 barrels per day). Also, in Indonesia, two of the North Slope producers, Arco and Exxon, produce some 135,000 and 30,000 barrels per day respectively. Until 1976, exploration and development activity was flourishing under the government's production sharing system, where the government took 65% of the oil produced leaving 35% for the companies. (The shares were calculated after the company recovered its costs by taking up to 40% of annual production.)

23. Changes in both U.S. government and Indonesian government oil policy, in 1976, were followed by a decline in exploration activity. For one thing, the U.S. Internal Revenue Service ruled that U.S. companies operating in Indonesia could no longer deduct the government's share of production for purposes of computing U.S. income taxes. In addition, the

Indonesian government changed oil policy so that the share of profits going to the government increased, from 65% to 85%, (and also decreased the percentage of annual production available for cost recovery, from 40% to roughly 25%). All in all, the companies were left with only about 12% of the profits. (after taking into account that the companies had to sell some oil to the government at below market prices.) The end result was a decline in exploration drilling in 1977 of 20% (Petroleum News, January 1979, p. 14). However, despite threats by the companies to reduce production, in 1977 it actually increased by over 10%.

24. To encourage exploration, in 1977 the government improved the cost recovery provisions, introduced a number of exploration incentives and altered the terms for sales of the company oil to the government for domestic use. Perhaps more importantly, the Internal Revenue Service ruled, in 1978, that the companies could deduct the government's production share for purposes of calculation of U.S. income tax. Thus, even though the Indonesian government capitulated on a few points, its take has increased significantly compared with 1976, from 65% to 85-89% at present (depending on allowances and oil sale terms : see Oil Daily, December 22, 1980, p. 15).

25. Since 1978, there have been no significant changes in Indonesia's oil policy, despite the fact that prices more than

doubled, increasing the profitability of the companies dramatically. Thus, their per barrel profits have increased to roughly $4 per barrel, from $1.25 to $1.50 in 1976, and Indonesia is now one of the most profitable oil exploration and development areas in the world. Consequently, Indonesia is now in the middle of an impressive oil boom, with exploration at record levels and a record number of new exploration contracts signed. (In 1980 the number of exploration wells drilled was 150% greater than in 1976; see Petroleum News, January 1981, p. 31.)

26. Malaysia

Unlike neighboring Indonesia, Malaysia has acted to reap a greater share of profits created by the major price increases of 1979. The country uses a complex tax system, which includes a 10% royalty, a 70:30 production sharing split after royalty and cost recovery, a 45% tax on the company's profits, a 25% export tax, and a 70% windfall's profit tax (which closely resembles that of the U.S.). The net result is that the government's take is 90 to 95% of oil profits, depending on the field and pricing assumptions. Yet, under these arrangements, Exxon, which produces 1/3 of Malaysia's crude, has continued exploration work. (Tax information and government split are from a report by Walter Levy Consultants "Comparative Analysis of Exploration Arrangements of Selected Countries: Appendices", New York, 1981.)

27. In comparing the profitability of Alaskan oil with that elsewhere in the world, it is quite clear that it is probably the most profitable investment area in the world. For one thing, the per-barrel profit rate and the DCF profit rate are among the highest in the world. Moreover, other nations intervene in the oil industry much more forcefully through controls on pricing and marketing and limits on management decision-making, and are much less secure sources of oil supply.

Sources of Data for Table

Prices

All prices from Weekly Petroleum Status Report, 12-5-80, p.21 except Egypt; from Petroleum Intelligence Weekly,1-12-81,p.11; Canada, from Oil and Gas Journal,3-30-81,p.46 ; and Alaska, from Petroleum Intelligence Weekly, 3-16-81.

Saudi Arabia

All data from Petroleum Intelligence Weekly,5-19-80,p.10.

Venezuela

All data from Petroleum Intelligence Weekly, 11-19-79,p.5.

Nigeria

All data from Petroleum Economist,2-81,p. 54.

Indonesia

Data from Oil Daily , 12-22-80,p. 15, and Petroleum News, 1-81,pps.20-32.

Malaysia

Data from Petroleum Intelligence Weekly, 6-2-80,p.4-5 and W.J. Levy Consultants Corp. , Comparative Analysis of Exploration Arrangements in Selected Countries,(New York; W.J. Levy Consultants, 1981) tables A-7 to A-10.

Egypt

All data from Petroleum Economist, 1-80,p.35.

Norway

Costs range from Dillar P. Spriggs of Petroleum Analysis Ltd., "Oil Tax Policy in the North Sea and North America", OPEC Review, Autumn 1980, p.63, Petroleum Intelligence Weekly 7-16-78,p.63 and Petroleum Intelligence Weekly,12-8-80,p.8. Division of Profits from OPEC Review, op. cit. and Storting Report no. 53: Concerning the Activity on the Norwegian Continental Shelf (Norwegian Government Mininstry of Petroleum and Revenues, 1980)

United Kingdom

Costs are from same sources as Norway.
Division of profits from, Major Features and Trends in Contracts and Agreements in the International Petroleum Industry (New York; United Nations Centre on Transnational Corporations, 2-81) adjusted for new tax and OPEC Review op. cit. p. 61, and Oil and Gas Journal, 3-23-81,p. ~~119~~ 67

Canada

Costs from OPEC Review, op. cit. p.59 and Alaska Legislature, Nonpartisan Research Bureau (via telephone).
Division of profits from Petroleum Economist, 12-80 p.511.

Alaska

Data from Petroleum Intelligence Weekly, 3-16-81 , and Memorandum to Hon. Ed Dankworth, from Milt Barker, 1-16-81, "Revisions in Petroleum Taxation" Alaska State Legislature .

U.K. and Norway costs are assumed to be roughly the same.

(16) [Effective February 1, 1981] Repealed by § 11 ch 1 SSSLA 1980.

(17) [Effective February 1, 1981] Repealed by § 11 ch 1 SSSLA 1980.

(am § 11 ch 1 SSSLA 1980)

Effect of amendment.

The 1980 amendment effective February 1, 1981, repealed paragraphs (4), (7), (13), (14), (16) and (17), which define "fiduciary," "individual," "domicile," "nonresident," "residence," and "resident," respectively.

Editor's note. — For legislative findings and purpose of the 1980 amendment, see § 1, ch. 1, SSSLA 1980, in the 1980 Temporary and Special Acts and Resolves.

Chapter 21. Oil and Gas Corporate Income Tax.

Section

10. Application
20. Determination of taxable income from oil and gas production
30. Determination of income from oil and gas pipeline transportation
40. Determination of income from activities other than oil and gas production or pipeline transportation
50. Assessment of income and tax
60. Returns
70. Payment of tax
80. Transitional rules
90. Regulations
100. Penalties
110. Public reporting
120. Definitions

Editor's note. — As to legislative findings and intent, see § 1, ch. 110, SLA 1978, in the 1978 Temporary and Special Acts and Resolves.

Section 4, ch. 110, SLA 1978, provides: "This Act applies to taxable income earned or received after December 31, 1977."

Sec. 43.21.010. Application. This chapter applies to every corporation doing business in the state which derives income from the production of oil or gas from a lease or property in the state, or from the pipeline transportation of oil or gas in the state. The tax calculated under this chapter is measured by the total taxable income of the corporation as defined in AS 43.21.020 — 43.21.040 and is determined at the rates established under AS 43.20.011(e). (§ 3 ch 110 SLA 1978; am § 28 ch 113 SLA 1980)

Effect of amendment. — The 1980 amendment, effective June 21, 1980, and retroactive to January 1, 1978, deleted "or directly associated with" following "a lease or property in" near the middle of the first sentence.

Editor's note. — Section 60, ch. 113, SLA 1980, effective June 21, 1980, makes this section applicable to tax years beginning after December 31, 1977.

Sec. 43.21.020. Determination of taxable income from oil and gas production. (a) The taxable income of a corporation from the production of oil and gas from a lease or property in the state shall be the corporation's net income as calculated by the department in accordance with this section.

(b) Gross income of a corporation from oil and gas production shall be the gross value at the point of production of oil or gas produced from a lease or property in the state. The department shall by regulation determine a uniform method of establishing the gross value at the point of production. In making its determination the department may use the actual prices or values received for the oil or gas, the posted prices for the oil or gas in the same field, or the prevailing prices or values of oil or gas in the same field. In addition, in its determination of gross value at the point of production of oil or gas produced from a lease or property, the department shall determine the reasonable costs of transportation from the point of sale to the point of production of the oil or gas. Transportation costs set by a tariff properly on file with the Alaska Pipeline Commission or other regulatory agency shall be considered prima facie reasonable, but if a tariff properly on file with a regulatory agency is subsequently amended, changed, or overturned retroactively, the reasonable costs of transportation shall be recomputed for that period using the newly determined tariff.

(c) Net income from oil and gas production shall be determined by the department by deducting from gross income the following:

(1) royalties paid in kind or in value;

(2) taxes imposed under AS 43.55 and AS 43.57 which are actually paid by the corporation on the production from a lease or property in the state;

(3) taxes imposed under AS 43.56 and AS 29.53 which are actually paid by the corporation on property used directly in the production of oil or gas from a lease or property in the state, including property used in production, gathering, treatment or preparation of the oil or gas for pipeline transportation, but only if those property tax payments were due and payable only after the date of commercial production from the lease or property with which the property was associated;

(4) the direct costs incurred by or for the corporation in operating the lease or property, including the direct costs of producing, gathering, treating or preparing the oil or gas for pipeline transportation, but not of any payments received for those activities and not including any indirect cost or overhead expense;

(5) depreciation (using the unit of production method or such other reasonable methods as the department may by regulation establish) on property used directly in the production, gathering, treatment or preparation of the oil or gas for pipeline transportation including amortization of capitalized interest for investments in this property at a rate not to exceed the average cost of borrowed capital to the taxpayer during the year in which it is capitalized;

(6) the amortization of lease acquisition payments and taxes paid under AS 43.56 and AS 29.53 (including capitalized interest on both) for or on producing properties before the commencement of commercial production from the lease or property for which the property is being used;

(7) interest expense of the corporation not capitalized during construction, to the extent that it does not exceed that portion of the total interest paid by the consolidated business of which the corporation is a part, determined by multiplying the total interest (reduced by intercompany transactions within the consolidated business) by a fraction, the numerator of which is the value of the corporation's real and tangible personal property used directly in the production of oil or gas from a lease or property in the state and the denominator of which is the value of all real and tangible personal property of the consolidated business;

(8) expenses incurred by the corporation after December 31, 1977 of unsuccessful exploration of oil or gas in the state including the acquisition costs of abandoned properties, dry hole costs and the costs of geologic and geophysical exploration related to those abandoned properties;

(9) general overhead or administrative expense incurred by the corporation attributable to the production of oil or gas from a lease or property in the state to the extent that it does not exceed the lesser of:

(A) that portion of the total general overhead or administrative expense incurred by the consolidated business of which the corporation is a part, determined by multiplying the total general overhead or administrative expense by a fraction, the numerator of which is the value of the corporation's real and tangible personal property used directly in the production of oil or gas from a lease or property in the state and the denominator of which is the value of all real and tangible personal property of the consolidated business, or

(B) the sum of $0.12 for each barrel of oil and $0.02 for each thousand cubic feet of gas produced from a lease or property in the state.

(d) Deductions from gross income under this section shall not include expenses previously deducted on a return filed under AS 43.20.

(e) Where a corporation subject to this chapter shares the production or proceeds of the production from a lease or property through a working interest, royalty interest, overriding royalty interest, production payment, net profit interest, joint venture or other agreement, the department shall allocate the deductions from gross income between the corporation and the persons with whom it has such an agreement in accordance with the terms of the agreement. (§ 3 ch 110 SLA 1978; am § 29 ch 113 SLA 1980)

Effect of amendment. — The 1980 amendment, effective June 21, 1980, and retroactive to January 1, 1980, in paragraph (7) of subsection (c), inserted "of the corporation" and substituted "during construction" for "of the corporation", both near the beginning of the paragraph.

Editor's note. — Section 52, ch. 113 SLA 1980, effective June 21, 1980, makes this section applicable to tax years beginning after December 31, 1979.

Sec. 43.21.030. Determination of income from oil and gas pipeline transportation. (a) Except as provided in (c) of this section, taxable income attributable to the transportation of oil in a pipeline engaged in interstate commerce in Alaska shall be determined by the department and shall be the amount reported or that would be required to be reported to the Federal Energy Regulatory Commission or its successors as net operating income, less those portions of interest and general administrative expense attributable to the pipeline transportation of oil in the state, except that taxable income shall also include taxes on or measured by income. The department shall establish regulations governing the determination of interest and general administrative expense attributable to pipeline transportation of oil in the state.

(b) Except as provided in (c) of this section, taxable income attributable to the transportation of natural gas in a pipeline engaged in interstate commerce in Alaska shall be determined by the department and shall be the amount reported or that would be required to be reported to the Federal Energy Regulatory Commission as net operating income less that portion of interest and general administrative expense attributable to pipeline transportation in the state, except that the taxable income shall also include taxes on or measured by income. The department shall establish regulations governing the determination of interest and general administrative expense attributable to pipeline transportation of natural gas in the state.

(c) Taxable income attributable to the transportation of oil or natural gas in Alaska of any corporation not under the Federal Energy Regulatory Commission jurisdiction, or of a corporation under the jurisdiction of the Federal Energy Regulatory Commission but not reporting the operation of pipelines in Alaska separately from the operation of pipelines elsewhere, shall be determined by the department and shall be based upon an amount equal to that which would have been reported to the Federal Energy Regulatory Commission under (a) of this section in the case of oil pipelines, or (b) of this section in the case of natural gas pipelines, had the corporation been, in fact, under Federal Energy Regulatory Commission jurisdiction for the taxable year and required to report on the operation of Alaska pipelines separately from the operation of pipelines elsewhere. (§ 3 ch 110 SLA 1978)

Sec. 43.21.040. Determination of income from activities other than oil and gas production or pipeline transportation. (a) Taxable income of a corporation subject to this chapter from activities in this state other than the production of oil or gas from a lease or property in the state or the pipeline transportation of oil or gas in the state shall be determined in accordance with the method established in art. IV of AS 43.19.010 and in AS 43.20.071, as modified by (b) — (f) of this section.

(b) The total taxable income of the consolidated business shall be the net income determined and certified by an independent certified public accountant for the purposes of a report to shareholders covering its earnings and profits for the taxable year (calculated without regard to any taxes on or measured by net income), less the earnings and profits of the consolidated business gained directly from oil and gas production and pipeline transportation.

(c) The numerator and denominator of the property factor, of the payroll factor and of the sales factor shall be calculated without reference to that portion of property, payroll or sales directly related to the production of oil or gas from a lease of property in the state or the pipeline transportation of oil or gas in the state.

(d) Compensation earned by employees of the consolidated business who are employed in the United States but not in any state shall be included in the numerator of the payroll factor if the employees are directly supplied from a base of operations maintained in this state.

(e) The value of oil or gas production facilities or other properties of the consolidated business which are located in the United States but not in any state shall be included in the numerator of the property factor if the property is serviced or supplied from a base of operations maintained in the state or if that property relies on onshore facilities in this state for storage of the oil or gas produced.

(f) The value attributed to vessels transporting Alaskan oil or gas of the consolidated business which are not owned or effectively owned by the consolidated business shall be excluded from the property factor. (§ 3 ch 110 SLA 1978; am §§ 30 — 32 ch 113 SLA 1980)

Effect of amendment. — The 1980 amendment, effective June 21, 1980, and retroactive to January 1, 1978, in subsection (a), substituted "(f)" for "(e)" near the end of the subsection, in subsection (b), substituted "earnings and profits of the consolidated business gained directly from oil and gas production and pipeline transportation" for "taxable income of the corporation as determined under AS 43.21.020 and 43.21.030" at the end of the subsection, and added subsection (f).

Editor's note. — Section 50, ch. 113, SLA 1980, effective June 21, 1980, makes this section applicable to tax years beginning after December 31, 1977.

Sec. 43.21.050. Assessment of income and tax. (a) The department shall assess taxable income and the amount of tax payable on that taxable income.

(b) On or before August 15 of each year the department shall send to every corporation taxable under this chapter a notice of assessment showing the amount of income taxable under this chapter for the previous year and the amount of tax payable on that taxable income.

(c) For purposes of this chapter the department may combine taxable incomes of corporations subject to tax under this chapter who are part of the same consolidated business. (§ 3 ch 110 SLA 1978)

Sec. 43.21.060. Returns. On or before April 15 of each year, a corporation subject to tax under this chapter shall submit a return in a form prescribed by the department setting out information required by the department to determine taxable income. For purposes of this chapter, the department may require corporations subject to tax under this chapter who are part of the same consolidated business to file a single return. (§ 3 ch 110 SLA 1978)

Sec. 43.21.070. Payment of tax. The tax levied under this chapter is payable to the department on or before September 30 of each year or in installments at the times and under the conditions the department may by regulation require. This tax is payable on the due date set out in this section even though the assessment is under appeal or the validity, enforceability or application of this chapter or any provision of this chapter is challenged before the department or in the courts. (§ 3 ch 110 SLA 1978)

Sec. 43.21.080. Transitional rules. The department shall provide by regulation transition rules for corporations subject to tax under ch. 20 of this title before July 9, 1978 to avoid double taxation of the same income or double deduction of the same expense of those corporations as a result of becoming subject to tax under this chapter. (§ 3 ch 110 SLA 1978)

Sec. 43.21.090. Regulations. The department may adopt regulations in accordance with the Administrative Procedure Act (AS 44.62) as appropriate to administer and enforce this chapter. (§ 3 ch 110 SLA 1978)

Sec. 43.21.100. Penalties. The penalties established in ch. 20 of this title apply to this chapter. (§ 3 ch 110 SLA 1978)

Sec. 43.21.110. Public reporting. (a) The commissioner of revenue shall compile and transmit to the legislature an annual consolidated report of state revenues and taxation policies under this chapter. This report shall include total aggregate income tax paid by corporations covered under this chapter and aggregate income and deductions by category, so classified as to prevent the identification of particular returns or reports.

(b) The legislative auditor shall transmit to the legislature an annual report reviewing the actions of the department in administering this chapter. (§ 3 ch 110 SLA 1978)

Sec. 43.21.120. Definitions. Unless the context requires otherwise the definitions contained in AS 43.55.140 are applicable to this chapter. In addition, in this chapter

(1) "base of operations" means the closest point on land to the offshore oil or gas production operations from which goods, services and supplies flow to those offshore oil or gas production operations;

(2) "consolidated business" means a corporation or group of corporations having more than 50 percent common ownership direct or indirect, or a group of corporations in which there is common control either direct or indirect as evidenced by any arrangement, contract or agreement. (§ 3 ch 110 SLA 1978; am § 33 ch 113 SLA 1980)

Effect of amendment. — The 1980 amendment, effective June 21, 1980, and retroactive to January 1, 1978, substituted "more than" for "at least" in paragraph (2).

Editor's note. — Section 50, ch. 113, SLA 1980, effective June 21, 1980, makes this section applicable to tax years beginning after December 31, 1977.

Chapter 23. Permanent Fund Dividends.

Effective date of chapter. — Section 6, ch. 21, SLA 1980, makes this chapter effective April 16, 1980, in accordance with AS 01.10.070(c). Section 5 of that chapter provides: "Sections 1 and 2 of this Act are retroactive to January 1, 1979."

Editor's note. — Section 1, ch. 21, SLA 1980, effective April 16, 1980, and retroactive to January 1, 1979, provides: "POLICY, PURPOSES AND FINDINGS. (a) It is the duty and policy of the state with respect to the natural resources belonging to it and the income derived from those natural resources to provide for their use, development, and conservation for the maximum benefit of the people of the state.

(b) The purposes of this Act are

(1) to provide a mechanism for equitable distribution to the people of Alaska of at least a portion of the state's energy wealth derived from the development and production of the natural resources belonging to them as Alaskans;

(2) to encourage persons to maintain their residence in Alaska and to reduce population turnover in the state; and

(3) to encourage increased awareness and involvement by the residents of the state in the management and expenditure of the Alaska permanent fund (art. IX, sec. 15, state constitution).

(c) The legislature finds that the accrual of permanent fund dividends provided in AS 43.23 enacted in sec. 2 of this Act, based on full years of residency since January 1, 1959, fairly compensates each state resident for his equitable ownership of the state's natural resources since the date of statehood. It is in the public interest to distribute a portion of Alaska's energy wealth to the people of the state.

(d) The legislature also finds that state residents have been paying increasingly high prices for fossil fuels, while few have received direct monetary benefits from the production and development of fossil fuels belonging to them as Alaskans. It is in the public interest to return to state residents a portion of the state's income from oil, gas, and other mineral production to help offset rising fuel costs.

(e) The legislature also finds that there exists in the state a serious problem of population turnover. A substantial portion of the state's population is comprised of individuals who reside in Alaska for only a relatively short time. This constant turnover in population leads to political, economic, and social instability and is harmful to the state. It is in the public interest for the state to promote a stable resident population by providing an incentive to encourage Alaskans to maintain their residency in the state."

Section 3, ch. 21, SLA 1980, as amended by § 1, ch. 60, SLA 1980, effective June 5, 1980, provides: "For 1979 the value of a permanent fund dividend is $50. The payment of permanent fund dividends for 1979 shall be made from an appropriation from the general fund to the dividend fund for that purpose. The amount appropriated from the general fund to pay permanent fund dividends for 1979 less 50 percent of the income of the Alaska permanent fund earned during the fiscal year ending June 30, 1978, is a loan to the dividend fund from the general fund which shall be repaid as provided in AS 43.23.050(c) enacted by sec. 2 of this Act. The Department of Revenue shall by July 1, 1980, prescribe and make available an application form for claiming permanent fund dividends for 1979. The Department of Revenue shall mail the form to each individual who, before July 1, 1980, filed a resident or part-year resident Alaska net income tax return for the 1979 tax year under AS 43.20. An eligible individual may receive payment of permanent fund dividends for 1979 if he applies to the Department of Revenue on the form prescribed by the department no later than November 15, 1980. The application must be accompanied by a statement of eligibility as required by AS 43.23.020 enacted in sec. 2 of this Act."

Section 4, ch. 21, SLA 1980, effective April 16, 1980, provides: "If any provision enacted in sec. 2 of this Act is held to be invalid by the final judgment, decision or order of a court of competent jurisdiction, then that provision is nonseverable, and all provisions enacted in sec. 2 of this Act are invalid and of no force or effect."

Sec. 43.23.010. Eligibility for permanent fund dividend. (a) An individual who is eligible under (b) of this section is entitled to one permanent fund dividend for each full year that the individual is a state resident after January 1, 1959.

(b) For each year, an individual is eligible to receive payment of the permanent fund dividends for which he is entitled under this section if he

(1) is at least 18 years of age; and

(2) is a state resident during all or part of the year for which the permanent fund dividend is paid.

(c) To determine the number of permanent fund dividends to which an individual is entitled under (a) of this section, a year in which the individual is a state resident for less than 12 months may not be counted, but a payment of a permanent fund dividend may be made for that year under (f) of this section. A year for which an individual was entitled to payment of a dividend but failed to file a claim may be counted to determine the number of dividends under (a) of this section.

(d) An individual may receive payment of a permanent fund dividend in a single payment or in 12 equal installments paid monthly by the department.

(e) An individual eligible to receive payment of a permanent fund dividend may elect to defer receipt of that payment. The commissioner

draft

Letter of Intent

HOUSE FINANCE COMMITTEE SUBSTITUTE FOR SSSB 524(Fin)

HCSCSSSB 524(Fin) provides an increase in the investment tax credit allowed for in state investments for corporations doing business in Alaska. In addition, the House Finance Committee substitute includes the revisions to tax chapters AS 43.20, AS 43.21, 43.55, and AS 43.58 introduced by the Governor in Sponsor Substitute for HB 200, and the record and report of the Special Gas Pipeline Committee on SSHB 200 is incorporated as part of the House Finance Committee record and report on HCS CSSB 524.

Rep. Sam Cotten, Chairman
House Finance Committee

ALASKA OIL AND GAS INCOME TAXATION

A Review of the State's Current Options

prepared for

The Alaska State Legislature
Joint Gas Pipeline Committee

By

[illegible]ESTON, THORGRIMSON, ELLIS & HOLMAN

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April 15, 1981

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FOREWARD

This study was prepared under a contract with the Legislative Affairs Agency of the Alaska State Legislature. The agreement directed us to

> . . . review and report on the options available for implementing the goals established in the Joint Statement on Oil Taxes issued by the Governor, the President of the Senate, the Speaker of the House, the Finance Chairmen of their respective houses and other legislative leaders on March 18, 1981.

It was specified that our report should include

> legal, economic and fiscal analysis of the various options identified . . . to enable an informed choice of options for further consideration. . . [and our] recommendations as to the identified options.

Although the time allowed to fulfill this assignment was extremely limited (13 days), we have prepared a reasonably comprehensive survey of the State's options. However, the analysis here is not sufficiently detailed to support any final decision on the form of a new oil tax structure, be it temporary or permanent. We do see this document, and the work by others now underway, as useful and perhaps crucial to narrowing the focus of efforts in the immediate future if it is decided to proceed.

The report which follows is the joint product of the three authors. The supporting revenue and economic studies were the responsibility of Mr. Eppenbach and Mr. Erickson. The necessary legal analysis was carried out by Mr. Messenger, who also served as project manager.

We wish to thank the many individuals who, often on very short notice, generously made themselves available to

answer our questions and who provided us with much useful data. Personnel of the Department of Revenue must lead this list--Commissioner Thomas Williams, Deputy Commissioner Joseph Donohue, Director of Petroleum Revenue Robert Johnson, Jerry Heier, Lou Nelson, and especially Charles Logsden. Mark Wittow and Kevin McCarthy of the legislative staff also provided important information, as did Milt Barker of the Legislative Finance Division. The use of data processing facilities at the House Research Agency was crucial to producing this study within the specified time.

I

OVERVIEW

A major part of the revenues expected to accrue from Alaska's oil and gas resources have been put at risk by a lawsuit challenging A.S. 43.21, the State's oil and gas corporate income tax (hereinafter "Ch. 21"). If the litigation is finally resolved in late 1985, the State could--in the worst case--be required to return up to $9 billion to the corporate taxpayers (see Table I).

TABLE I

ESTIMATED CH. 21 (PETROLEUM INCOME TAX)
COLLECTIONS BY FISCAL YEARS
(Millions of Dollars)

Fiscal Year	Annual Collections
1979	233 (actual)
1980	548 (actual)
1981	808
1982	1303
1983	1541
1984	1783
1985	2141
Total for period	8357

In a March 18, 1981 Joint Statement, the legislative leadership and the administration (see Appendix A) announced Alaska's position with respect to this risk: The current share of oil revenues between the producers, the federal government, and the State is fair; it should be preserved in

the future as a model of stability and restraint for other petroleum producing jurisdictions. These goals--and Alaska's established revenue share--will be seriously compromised if the plaintiffs win.

Although legal opinions differ on the State's chances of prevailing in the current lawsuit, no one has suggested that it is free from risk. The large sums involved make even a small victory by the litigants (or a small probability of a big victory) a matter of serious concern.

If the litigation result is a relatively small loss (say $1 billion in 1985), it could be recouped over a few years with increased petroleum taxes. A loss of any larger magnitude would place the State in financial extremis. One option to deal with this problem is to await the outcome of the lawsuit before taking action. There are, however, real economic, legal and political restraints on recouping a substantial portion of lost Ch. 21 revenues under this option.

One way of implementing this option would be to attempt to collect the lost revenues prospectively. The State's oil and gas resources and the oil and gas tax base whether measured by gross production revenues, income streams, or reserves valuation, is depleting. The ability to offset this depletion by raising the tax rates has economic limits. This is especially true if one is attempting to cover lost revenues and also provide for the then current needs. In addition, there are real--albeit poorly defined--political and constitutional limits to the tax rates that would be

required to cover both past lost revenues and future needs. The legal challenge of Montana's 30 percent severance tax (now before the U.S. Supreme Court) and congressional proposals to limit state severance and income taxes are some examples.

Alternatively, in the event of an unfavorable decision, the State could attempt to make up the loss by making tax changes retroactively to 1978. A serious constitutional question would be raised by such a retroactive imposition. States have some latitude in imposing taxes retroactively, but not without limit. Taxes made retroactive to the beginning of a current tax year or applied to recent transactions have been upheld. Similarly, curative statutes which cure invalid tax proceedings or administrative action retroactively have been sanctioned. On the other hand, some other retroactive impositions such as gift and death tax changes have been struck down on the ground that the nature or amount of the tax could not reasonably have been anticipated at the time of the transaction which was later made taxable. Although not entirely clear, tax changes in 1985 of the magnitude needed to cover a loss of Ch. 21 revenues and the period of retroactivity (seven years to 1978) would at least carry a serious legal risk.

Since waiting out the law suit would still leave State revenues at risk, we believe that a decision to do nothing other than litigate the suit will not constitute, in the language of the Joint Statement, "a sound strategy for

protecting oil and gas revenues."

This does not mean that an aggressive effort to win the current litigation is unimportant. Indeed, we consider it an essential part of any plan for protecting the State's revenues. Even if the current oil and gas corporate tax, A.S. 43.21 were repealed this session and replaced by some other tax that raised as much revenue, the result would be to leave in excess of $1 billion already collected by the State at risk.

This billion dollar "overhang" has important implications for the State's efforts to achieve the objectives outlined in the joint statement. Because of the overhang, any new tax designed to replace Ch. 21, or any attempt to create a "saftey net" tax to backstop Ch. 21 (which was enacted in 1978), must either be retroactive to 1978, or otherwise protect more money than the oil and gas corporate tax will collect in future. As we shall show later, this constraint limits the options available to the legislature.

Whether to replace Ch. 21 with a new permanent tax, or to simply protect its revenues with a backstop of some sort is a decision that turns on the degree and range of certainty required with respect to policy, fiscal and legal issues.

On the one hand, to fashion a workable backstop the legislature need mainly be concerned with fiscal effects as they unfold over a limited time span, between now and whenever the litigation is finally resolved, say 1985. Further, the basic criteria that a backstop must satisfy are rela-

tively simple. First, it must have sufficient fiscal horsepower to cover the exposed Ch. 21 revenues. Second, it must be legally (and politically, with respect to the federal government) secure.

Before adopting a permanent substitute for Ch. 21, we expect that the legislature will wish to give it a far more searching examination than would be necessary under the backstop approach. For example, the fiscal effects of a new permanent tax should be examined under a larger set of possible circumstances, and over a longer time frame. Its effects on future exploration and development, for example, would need to be forecast under a similarly wide range of alternative assumptions, as would its effects on differently situated oil and gas producers, and pipeline operators. Most of all, the legal and fiscal security of a replacement must be close to absolute, since a new tax is not the second and reinforcing line of defense that would be created by a backstop; it is a new first line of defense which must stand alone.

In all candor, we doubt that these conditions can be met in the time remaining in this session. Our experience with this type of legislation, going back to 1972, leads us to believe that consensus on the issues raised by a whole new permanent petroleum income tax will require substantial work to achieve. This was certainly the case in 1978, when Ch. 21 was enacted. Numerous concepts for revising the tax were introduced by different legislators and the administra-

tion over the three years preceeding enactment of Ch. 21. Two interim committees approached the task and arrived at very different policy recommendations. After a general consensus had been reached, it took six weeks of very intensive effort to embody the concept in an act that everyone could be reasonably confident would do what was expected of it.

Much of the work done over the 1975-1978 period is and would be relevant to recasting the tax now; but even so, the policy differences are likely to remain. For example, some will claim that two corporations with exactly the same Alaska assets, activities and profits will be taxed differently, and therefore inequitably under any apportionment formula. Others will argue that apportionment is the most appropriate way to tax a unitary business. Similarly, resolving legal questions and revenue projections with reasonable degrees of certainty would surely require much further analysis. Resolving issues of this sort, if they are resolvable, will take time.

II

BACKSTOP CRITERIA

A backstop is much more likely to be achievable within the six weeks or so remaining in this session, but even so, developing a backstop tax will not be a simple task. To serve its purpose a backstop measure must (1) have sufficient fiscal horsepower to cover the revenues at risk, and (2) be legally and politically secure. Some tax bases are probably not large enough to achieve both of these objectives in an absolute sense. As a result, a marginal increment of revenue security would need to be given up to achieve the highest possible legal security (or vice versa). For example, as we note below, any apportionment formula that raises as much revenue as Ch. 21 will almost certainly be challenged and will carry some legal risk.

These matters, and the question of tradeoffs, are addressed below in the context of specific taxes. However, in order to assess these, it is necessary to discuss the other secondary goals which the legislature will probably consider relevant. These are, in no particular order, the following:

Minimize Adverse Effects on the Current Lawsuit. For example, a backstop tax which made use of the three factor apportionment formula which the oil company plaintiffs are arguing for in their suit could be construed as giving them at least moral support in their assertions, and raise questions about the State's own confidence in that part of its

case. The same could be said about any backstop tax, but a specific use of the plaintiffs' favored approach could be especially difficult to explain.

Administrative Convenience. In the context of the large sums we are discussing here the extra costs of administering even the most difficult tax are not very significant. Moreover, the assertions made to previous legislatures by the petroleum industry that the 1975 reserves tax and the 1978 corporate tax proposal would create an "administrative nightmare" and "a huge revenue bureaucracy" have not been validated by actual experience with those taxes.

On the other hand, the fact that some taxes are easier to administer than others is not irrelevant. For example, the very simple reserves tax requires, in the assessment process, substantial technical skill and high levels of administrative integrity. The fact that the Alaska Department of Revenue managed this tax quite well for the two years it was in effect probably does not entirely mitigate the importance of administrative convenience.

Simplicity. By this we mean that the tax should be known and understandable. Taxes which the legislature has already dealt with in the past are to be prefered, other things being equal, to those that are relatively untried or complex in their workings. The severance tax, the reserves tax and the existing apportioned income tax in Ch. 20 all score high in this regard.

Overcollecting. It is important that Alaska not reach

beyond its stated goal of protecting its current share of petroleum revenues. This does not mean that a backstop tax or mechanism need collect or cover collections of exactly the same revenues as will be raised by Ch. 21, which in any event are uncertain. It does mean, however, that the collections should be comparable.

Minimize the Likelihood of Adverse Federal Reaction. Much has been said about the risks of congressional reaction to Alaska's attempts at securing what it considers its fair share of resource revenues. Consuming states have shown increased willingness to use political and judicial tools to limit that share to what they consider fair. The suit against Montana's 30 percent coal severance tax is an example.* Additionally, there have been several congressional proposals which would limit state severance and income taxes.** Although none of these proposals have become law, they can not be dismissed. Action which Alaska might take could have an effect on such proposals.

Symmetry. The taxpayers affected by a backstop, and the tax burdens it currently or prospectively creates should correspond as nearly as possible with Ch. 21, in order that the backstop not disturb the policy judgments already made by the legislature.

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* Commonwealth Edison Co. v. State, 615, P.2d. 847 (Mont. 1980).

** Just some of these proposals include S.1778 96th Cong. 1st Sess. (1979); H.R. 1983 97th Cong. 1st Sess. (1981); S.655 97th Cong. 1st Sess. (1981); H.R. 5076 96th Cong. 1st Sess. (1979); S.1688 96th Cong. 1st Sess. (1979).

Obviously, perfect symmetry in this sense is not possible without knowing each taxpayer's particular tax position. Although it might be desirable from a policy standpoint, achieving that perfect symmetry would carry some additional legal risks. For example, suppose A.S. 43.21 were found invalid, but through the adoption of a backstop mechanism each taxpayer was still required to pay exactly the same amount. An argument could be made that the legislature was simply enforcing an otherwise invalid tax under the guise of a new tax.

Certainty of Revenue Effects. Those of us who have had responsibility for forecasting revenues have an acute sense of how important this criterion is. On one level, certainty of revenue effect means you are much less likely to find yourself mercilessly criticized for missing the mark on your revenue estimate. Beyond that, certainty of revenue effect means that State fiscal planning can be made with more confidence.

No tax can be forecast with complete certainty. Oil and gas taxes are difficult because they are extremely sensitive to world oil prices and to production. Some oil and gas taxes, however, are much more difficult than others. A flat cents-per-barrel tax is easy since there is only one variable to worry about. A corporate income tax using the apportionment formula is more difficult to forecast, since it depends on the entire world wide tax position of each taxpayer which may change from year to year.

Although legislators themselves are not likely to make the actual estimates, they have the same problem. A backstop tax which turns out to have protected less revenue than expected could be difficult to explain to those who, rightly, could care less about the technical problems of forecasting.

Minimize Spillover Effects. Spillovers include all the effects of a tax that were not intended. With respect to the taxes under consideration here, they can range from increased gas rates in Anchorage if a gas severance tax were part of a backstop mechanism, to effects on future exploration and development. Some spillovers may be positive: Some have suggested that earlier construction of the Northwest Gas Pipeline could conceivably result from including a gas reserves tax in a backstop arrangement.

A full analysis of just those spillovers that we consider likely would take as much space as this entire study. Fortunately, most of these will probably not be very significant because the backstop tax will be temporary and the backstop mechanism can mitigate spillover effects to some extent. Where spillover effects may have political or especially significant economic reprecussions, they have been identified in the discussion of the individual tax or backstop mechanism that could cause them.

III

TAX TYPES

In our analysis of the backstop approach, we have found it useful, at least initially, to separate the consideration of taxes, per se, from the mechanisms by which they would be made to protect the State's Ch. 21 revenues. For example, enacting a new tax and escrowing Ch. 21 revenues is one mechanism. Allowing Ch. 21 payments to be credited against the new tax is another. Either mechanism could be applied to any of the possible backstop taxes considered here.

A large set of possible taxes was considered in this survey, but all can be adequately described under three basic headings categorized by whether the tax base is (1) the gross revenues from the production stream of oil and gas, (2) the profits derived from that stream, or (3) the value of the property (including reserves) that makes the production possible.

The greater part of our analysis has been devoted to determining with as much certainty as possible the amount of what we have called fiscal horsepower inherent in each of these tax bases, as well as the political and legal constraints on Alaska's ability to achieve that horsepower.

These tradeoffs, horsepower against security, are discussed below in the context of the three specific tax types.

Production or Severance Taxes have several important advantages. They are generally easy to assess, and are a traditional means of raising revenue from the petroleum

industry. Most importantly in this context, a production tax has an inherently large potential for fiscal horsepower, as shown in Table II:

TABLE II

OIL PRODUCTION TAX ESTIMATES
AT CURRENT TAX RATES
(Millions of Dollars)

Fiscal Year	North Slope Production	Cook Inlet	Total
1981	1137	22	1159
1982	1592	36	1628
1983	1956	33	1989
1984	2281	32	2313
1985	2533	25	2558

A change in the nominal rate under the existing severance tax from 12.25 percent to about 22 percent would raise sufficient revenue to cover Ch. 21 revenues.

The current severance tax formula allows for a tax rate modification based roughly on the marginal costs of production (see Table III). If this were eliminated, leaving a flat percentage of value severance tax, the required percentage of value would be between 20 and 18 percent, falling to the lower level in the last year of the backstop period (see Table IV). The fact that the power of a flat rate severance tax (no economic limit factor) grows over the backstop period is an important characteristic that could make it very useful in combination with a property tax on reserves, which shows the opposite tendency.

TABLE III

ANALYSIS OF OIL PRODUCTION TAX RATES

		North Slope		Cook Inlet	
Fiscal Year	Nominal Tax Rate	Estimated Effective Rates	Indicated Economic Limit Factor	Estimated Effective Rates	Indicated Economic Limit Factor
1981	12.25%	11.74%	.96	4.75%	.39
1982	12.25	10.79	.88	4.13	.34
1983	12.25	10.57	.86	3.98	.32
1984	12.25	10.46	.85	3.81	.31
1985	12.25	10.13	.83	2.89	.24

Note: The economic limit factor reduces the tax variably to take account of differing costs. See A.S. 43.55.

TABLE IV

NEEDED INCREASES IN OIL PRODUCTION TAX RATE TO OFFSET CH. 21 REVENUES BY YEARS (Dollar Figures in Millions)

Fiscal Year	Est. Ch.21 Revenues	Total Oil Production Tax Revenues	Required Nominal Rate With E.L.F.	Required Effective Rate
1982	1303	1627	22.05%	19.73%
1983	1541	1989	21.68	19.07
1984	1783	2313	21.68	18.58
1985	2141	2558	22.54	18.10

The principal problems with using the severance tax as a stand alone backstop are the potential political and legal liabilities associated with rates this high, and the potential spillover effects, mainly related to what has been termed the premature shutdown effect. A severance tax of 19 percent (effective rate) combined with a 12.5 percent royalty would mean that any production not earning over 68.5 percent of its cost would be shut down. These difficulties are much less significant at the lower rates possible if the severance tax were used in combination with another tax.

There are several variations on the severance tax which we have also considered. One of these, a state windfall profits tax modeled on the federal tax of the same name, would tax, say, 15 percent of the value of each barrel that exceeds a base price, which escalates with inflation. If the price of oil and the general price level were frozen at today's levels, a state windfall tax of 15 percent would be identical to a flat rate severance of about 6 percent.

The difficulty with a state windfall tax would come if oil prices don't rise as fast as general inflation. The high leverage of the tax would mean a rapid fall in tax revenues. In any event, certainty of effect is clearly a problem with the tax.

A State windfall profits tax might be considered by a court or Congress as simply a severance tax increase, and therefore might carry the same legal and political risks as a high severance tax rate. Additionally, it should be de-

termined whether an argument might be raised that the states are preempted by Congress from enacting a windfall profits tax.

Income Tax. The use of a new income tax to backstop Ch. 21 would probably require a return to some sort of apportionment formula. If that formula were the three factor one contained in A.S. 43.20, which the plaintiffs assert is the only correct one to use, the result is an evident lack of fiscal horsepower. Some have suggested that a roughly accurate rule of thumb is that the traditional three factor formula would raise about one seventh the revenues of Ch. 21.

The collections of any apportioned income tax depend on factors beyond the borders of Alaska, and would vary widely among producers who have very similar holdings in Alaska, depending on the vicissitudes of their business activities outside the State. This is why "rules of thumb" are so frequently used in estimating income tax revenues from apportionment taxes. Clearly, the apportionment taxes are not the best with respect to certainty of effect.

Using a non-traditional apportionment formula such as a one or two factor formula can increase the percentage of Ch. 21 revenue that might be raised, but in no case that we have seen proposed has the level exceeded 50 percent, assuming the same tax rate.

All of these non-traditional apportionment systems would probably be challenged by those who are now litigating

Ch. 21 on many of the same grounds and would carry some legal risk. Although an Iowa one factor formula was recently sustained by the U.S. Supreme Court the court was closely divided.* As a result, the state cannot take complete comfort in a non-traditional apportionment formula.

A property tax on reserves has almost enough fiscal horsepower by itself to cover Ch. 21 revenues. Table V shows the tax rate that would be required to protect current Ch. 21 revenues.

TABLE V

RESERVES TAX RATES REQUIRED
TO RAISE CH. 21 REVENUES

Fiscal Year	Ch. 21 Revenues	Prudhoe Field Valuation Base Case (Billions)	Required Tax Rate
1982	1303	48.6	2.68%
1983	1541	47.5	3.24
1984	1783	45.6	3.91
1985	2141	44.5	4.81

Base Case Assumptions:
1. Discount Rate = 19%
2. Federal Windfall Profits Tax continues in effect until December 31, 1991.
3. Other assumptions consistent with revenue estimates.
4. Prudhoe field only.

We feel confident that the higher tax rates would be legally sustained, but believe it appropriate to avoid going beyond

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* Moorman Manufacturing Co. v. Bair, 437 U.S. 267 (1978).

the usual range of property tax rates in the United States.

In addition to a relatively high horsepower, the property tax on reserves has the advantage of being simple in concept. Alaska had such a tax from 1975 to 1977, with both revenue officials and the reserves owners knowledgable about how the tax would work. A property tax on reserves does have some disadvantages. As Table V clearly shows, it tends to loose fiscal horsepower as the years pass, and as the field is depleted. A tax rate that covers current Ch. 21 revenues quite comfortably in FY 1982 would fall far short in subsequent years.

Another problem with a tax on reserves is that its yield is very sensitive to decisions made in the assessment process. For example, an increase in the discount rate from 18 percent to 19 percent will, as shown in Table VI, reduce the valuation and the yield by almost 10 percent.

PRUDHOE BAY
PRELIMINARY FIELD VALUATION RESULTS

Current Severance Tax Rates
Windfall Profits Tax Continues through CY 1993

Appraisal Date	Fiscal Year Payment Date	RESERVE VALUE IN BILLIONS 20% Discount Rate	19% Discount Rate	18% Discount Rate
1/1/81	1982	41.8	45.9	50.7
1/1/82	1983	40.2	44.2	48.9
1/1/83	1984	37.9	41.8	46.2
1/1/84	1985	36.1	39.8	44.2
1/1/94	1995	8.3	9.8	11.7

The discount rate which we have used in our base case calculations is 19 percent, one percentage point higher than Alaska's assessors used in 1975. This is reasonably conservative, and is based in part on conversations with reserves assessment experts in Texas.

IV

BACKSTOP MECHANISMS

A backstop mechanism is the means by which a tax or combination of taxes discussed above will prevent tax revenues from falling below current desired levels in the event that Ch. 21 is declared invalid either in whole or in part.

Arguably, one backstop mechanism is already in place--A.S. 43.20 (The general corporate income tax). The same act which imposed the new corporate income tax (Ch. 110 SLA 1978) on oil and gas production and pipeline transportation corporations also removed the imposition of A.S. 43.20 on those same corporations. If a court struck down Ch. 21 in its entirety, A.S. 43.20 could be revived. Once revived, it could backstop at least some of the revenue loss.

The State's general savings clause--A.S. 01.10.100--does not cover this type of situation. So there is no certainty that A.S. 43.20 would be revived. There is, however, legal support for the proposition that if a repealing act is found invalid, the repealing section also falls and the repealed section is revived. This is especially held true if the invalidated act was a substitution for the repealed act. Using this analogy A.S. 43.20 would be revived as to Ch. 21 taxpayers if the court struck down Ch. 21 in its entirety. Whether the revived A.S. 43.20 could then be retroactively imposed would depend upon whether the retroactive imposition was constitutionally permissable and

whether the assessments would be barred by the State's statute of limitations on assessments. As analyzed under the court tests previously discussed, a defensible argument could be made to support the retroactive imposition and assessment.

A more difficult situation is presented if a court only strikes down a portion of Ch. 21. A.S. 43.20 probably would be revived only if it could be easily incorporated with the remaining portion of Ch. 21 without overlap, and if a court were to find a clear legislative intent for such revival. It is probably unlikely that a court would fashion a new tax by piecing together portions of the two taxes.

In any event, if a court were to invalidate Ch. 21, a revived A.S. 43.20 would only backstop a small portion of the lost revenues.

In connection with the primary criteria already discussed, the backstop mechanism must itself withstand legal challenge, and operate to protect current expected revenues under all possible litigation outcomes. The backstop mechanisms should also satisfy, to the extent possible, the secondary criteria, such as avoiding spillover effects and overcollecting revenues.

We have analyzed a number of possible backstop mechanisms. The following three general approaches which show the most promise are:

1. A new tax or combination of taxes could be imposed and collected concurrently with the oil and gas corporate

income tax. The money collected from such tax or taxes would be available to fund government programs at a level established in the Joint Statement. The proceeds from the oil and gas corporate income tax could then be appropriated to an escrow account until the validity of the oil and gas corporate income tax is finally determined.

2. A new tax or combination of taxes could be triggered into effect by some future event such as a final court determination that Ch. 21 is invalid.

3. A new tax or combination of taxes could be imposed currently with a credit allowance between Ch. 21 and the new tax so that there would be no cumulative collection of both taxes.

Escrow Option. The adoption of a new tax to raise currently expected revenues and the escrowing of Ch. 21 revenues until the validity of A.S. 43.21 is determined is one backstop mechanism. Other variations of this option could be established such as escrowing the new tax rather than A.S. 43.21 revenues. The former approach, however, is probably more defensible since the new tax would have a clearly permissible public purpose--collecting revenues to fund State public programs. Similarly, the State could legitimately escrow tax monies which were under court challenge.*

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* In speaking of escrowing Ch. 21 revenues, we don't mean to imply that the legislature could mandate the escrow of revenues and bind future legislatures. This could be argued as a dedication of revenues prohibited by Art. IX, §7 of the Alaska Constitution. Successive legislatures could, however, appropriate the revenues collected under Ch. 21 to an escrow account.

Depending upon the tax base or bases chosen, this mechanism could fully backstop Ch. 21 revenues at risk. Likewise, the use of this mechanism is legally defensible assuming that the new tax is levied for the legitimate purpose of obtaining revenue to fund State public programs. The State clearly has the authority to impose taxes necessary to fund public programs and is not required to spend funds which it might have to refund as a result of a court challenge.

This option is not without drawbacks under the criteria which have been identified. First, although this mechanism could provide a complete backstop for revenues that might be lost, it also has the potential of collecting revenue beyond currently desired levels. Under this mechanism, if Ch. 21 were invalidated in total, the State would be able to refund Ch. 21 taxes and still be able to fund State programs without overcollecting. On the other hand, if Ch. 21 totally withstands challenge or is invalidated only in part, the State may have exceeded its desired level of revenue collection.

Second, because the State would be collecting both the new tax and Ch. 21 revenues with the potential of collecting beyond the desired revenue level the overall tax burden would be increased. This increased tax burden could create spillover effects such as altering taxpayer decision making and effecting future exploration and development.

Triggering Option. Another mechanism available to

backstop A.S. 43.21 revenues is the enactment of a tax or combination of taxes with an effective date contingent upon some future event. For example, a tax could be enacted which would be imposed retroactively upon a final court decision invaliding Ch. 21. Other variations of this option could be designed all involving a tax which is triggered into existence upon the happening of a future event.

Depending upon the tax base or bases chosen, this mechanism is capable of backstopping the total amount of Ch. 21 revenues which are at risk. With regard to the legality of this option, it should first be observed that it is not uncommon for legislation to be made effective upon the happending of some future event. The retroactive operation of such an option, however, does raise legal questions. As discussed previously, there are limits to the authority of the legislature to impose taxes retroactively. A court could determine that the enactment of the contingent tax was sufficient notice to taxpayers that a tax might be imposed, to be within permissible limits of retroactivity. This result, however, is not free from doubt.

Like the escrow mechanism, this option also has the potential for overcollecting revenues beyond the State's revenue goals. This stems from the practical problem of drawing the triggering mechanism so as to cover all the potential outcomes of the lawsuit. If a court were to strike down Ch. 21 in its entirely, this backstop mechanism could become effective to collect the level of revenues

needed by the State. If, on the other hand, only a portion of Ch. 21 revenues are lost from an adverse decision, a full collection under the new tax might be automatically triggered. Some tailoring of the mechanism might be made which could accomodate various levels of revenue loss but precision to meet every circumstance is probably not possible.

Credit Option. A third mechanism which could be used to backstop Ch. 21 revenues would be the imposition of a new tax or taxes which would be creditable against Ch. 21 or a new tax or taxes to which Ch. 21 tax payments could be credited.

This tax mechanism could be used with any tax base and assuming that tax base had sufficient horsepower is capable of backstopping the total amount of Ch. 21 revenues at risk.

Adopting a new tax which is creditable against other taxes or for which other taxes can be credited is a legally defensible taxing system. First of all, the new tax or taxes could be enacted for the purpose of collecting revenues necessary to fund public programs. Additionally, the legislature could legitimately decide to allow a tax credit for the purpose of avoiding a double taxation effect from the imposition of both an income tax and another tax which might be imposed with respect to the same property or activities. The use of credits to avoid double taxation effects is a commonly accepted taxing practice.

Unlike the overcollection potentials of the other mechanisms, the use of credit system comes the closest to col-

lecting the amount of revenues put at risk while at the same time not overcollecting beyond the revenue goals established by the legislature. For example, if Ch. 21 revenues were allowed as a credit against a new tax, and a subsequent court decision invalidated Ch. 21 in whole or in part, the refund of A.S. 43.21 revenues would be offset by an increase in the new tax by reason of the reduced credit.

Because the credit system minimizes the possibility of overcollecting, the overall tax burden should remain relatively the same. That in turn will serve to minimize spillover effects that might accompany an overall increase in tax burden.

By imposing the new tax immediately with a credit you also avoid the potential retroactivity problems associated with a triggering mechanism.

It is conceivable that taxpayers would cry foul to the use of any backstop mechanism since it would mean tax changes enacted during the pendency of their challenge of Ch. 21. Presumably these taxpayers would claim that the tax changes were made to punish those who challenged Ch. 21. If such were the case, it would certainly raise a serious legal question. However, as we have stated, a backstop can be supported by a clearly permissible public purpose--raising revenue necessary to fund public programs. The legislature having made a policy decision as to the level of needed public programs has authority to enact taxes necessary to raise revenues to support those programs. In making

these decisions the legislature certainly has the right to take into account the certainty of its revenues and the debts that might reduce its revenues. The legislature can adjust its tax structure to ensure sufficient revenues to meet its public programs.

V

CONCLUSIONS AND RECOMMENDATIONS

The contract under which this study was carried out specified that we should identify "options for further consideration." This must, if only by omission, identify those that do not deserve further consideration. We are uncomfortable with this latter implication, since we are unprepared ourselves to rule out the possibility that policy concerns of which we are unaware, or new facts might cause us to change our minds. Nevertheless, we are reasonably confident that the options identified below will, after further work, prove to be those most likely to meet the objectives of the Joint Statement, and the criteria discussed above.

1. The first issue is whether to seek a permanent replacement of Ch. 21 while the litigation challenging it is still pending, or to protect Ch. 21 revenues with a backstop, making revisions to Ch. 21 only in the event the State loses. We believe that the latter course is preferable because we have not identified any option which has the degree of revenue, legal and political security required to be a permanent replacement. As stated earlier, the fiscal and legal security of a replacement must be close to absolute, since a new tax is not the second and reinforcing line of defense that would be created by a backstop; it is a new first line of defense which must stand alone.

As stated sucinctly by the Governor in his budget message:

"Motivation for [this] litigation centers more on fiscal principal than legal principal. . ."

Consequently, any attempt to collect the same level of revenue by other means will have the same result--a lawsuit.

A replacement for Ch. 21 might still be in order if it could be demonstrated that the replacement was more secure than the combination of Ch. 21 with a backstop. This demonstration has not been made. If it were to be made, legislators would need further to decide whether the policy issues opened up by consideration of a replacement (as opposed to a backstop) could be resolved in the time available.

2. The backstop tax that appears to best meet the goals of the Joint Statement is a combination of a new severance tax and a reserves tax or a reserves tax by itself. A 15 percent effective rate severance and a 2.5 percent reserves tax or a four percent reserves tax (as shown in Table VII), would have the necessary fiscal horsepower to cover current as well as past Ch. 21 revenues at risk. It also appears to minimize legal risks, potential congressional reaction, and spillover effects. We recommend that the fiscal and economic analysis of these options be refined, and that the proposals be put in more concrete form.

3. With respect to a backstop mechanism, we recommend that further attention be focused on the credit option. Our preliminary analysis indicates that this option will effectively backstop Ch. 21 revenues with the tax types recommended. It also appears to minimize the legal risk, over-

collection potential, and spillover effects.

If this option is chosen, analysis of variations on the credit mechanism and their effects would be appropriate.

TABLE VII

REVENUE ESTIMATES
FOR RECOMMENDED OPTIONS
(Millions of Dollars)

Fiscal Year	Ch. 21 Revenue	4% Reserves Tax	15% Effective (16.67 Nominal) Plus 25 Mill Reserves Tax
1982	1303	1944	1801
1983	1541	1900	1903
1984	1783	1824	1973
1985	2141	1780	2033
Total	6768	7448	7710

Notes: North Slope reserve property tax estimates only. Cook Inlet valuations would increase these amounts. North Slope valuation assumes 19% discount rate and federal Windfall Profit Tax ending December, 1991.

APPENDIX A

JOINT STATEMENT ON OIL TAXES ISSUED
BY THE STATE ADMINISTRATION AND THE
LEGISLATIVE LEADERSHIP ON MARCH 18, 1981

Governor Jay Hammond and the leadership of both houses of the Legislature are united in an effort to arrive at the best course of action on pending oil and gas tax issues. Legal challenges by the oil industry have placed as much as one-third of the State's projected tax revenues in jeopardy.

Alaska's existing taxation and leasing policies currently provide significant incentives for petroleum exploration and development in the state. Hence, existing levels of taxation, stabilized since 1978, should remain stable at this time. On the other hand, any significant decreases in State oil and gas revenues appear both unwarranted and unsupported by the majority of Alaskans. The State's current level of taxation -- about one-sixth of the value of Prudhoe Bay production -- provides that both the oil companies and the federal government will receive greater shares of Alaska's wealth than will Alaskans. Accordingly, any greater percentage granted the former at the expense of the latter would be inequitable.

Both the Governor and the legislative leadership are determined that through their mutual efforts, a sound strategy for protecting oil and gas revenues will be found. All agree that any changes which would give large sums of money to the oil industry at the expense of the people of Alaska are unacceptable. The Prudhoe Bay bonanza will not last

forever. We must make use of those revenues now through investments such as hydroelectric power, renewable resource development, and permanent fund contributions which will provide for our future.

APPENDIX B

A NOTE ON RESEVOIR VALUATION METHODOLOGY

Resevoirs are generally appraised the same way as other income earning property; the possible future income from the resevoir is estimated and discounted back to the present at a rate that represents the return expectations of an hypothetical buyer. This was the method the State used to value the Prudhoe Bay field in 1975 and we used the same method in this study.

First, an appraiser needs a solid engineering estimate of the size, hydrocarbon content, and likely annual production rates of the field. For the Sadelrocheit Resevoir, we used the latest Alaska Oil and Gas Conservation Commission forecasts. For the Kuparuk and Lisburne fields, we relied on estimates provided by the Petroleum Revenue Division.

Next, we reviewed estimates of the future costs, both capital and operating, needed to purchase, build, install, and operate all of the equipment in the field. As the valuation method requires, we do not include past costs or financing expenses. Estimates of future costs were developed by H.K. VanPoollen Associates, Inc. in 1979, updated by us and the Legislative Finance Division to reflect recent changes and price increases.

A third major step is to forecast future prices for resevoir products and then net them back to the field. For these estimates, we relied heavily on the sophisticated

PETREV forecasting model operated by the Department of Revenue. In general, these estimates suggest little "real" price increase for oil in the world markets and an average rate of inflation of about 10 percent. Wellhead prices, however, are expected to increase rapidly as the TAPS line lowers its per-barrel tariffs. The current average wellhead price of about $25.00 is expected to rise to about $30.00 next year. For gas, given the uncertainty of its transportation and wellhead value, we assumed a flat $1.00 per MCF real price and sales beginning in fiscal year 1988.

Finally, with these decisions in hand, we scheduled the annual cash flows of the field. Using a computer, we estimated all of the production values, costs and expenses, royalties, excise, property and production taxes, and windfall profits taxes. Since valuations are traditionally based on estimates of before tax income, we did not include a calculation of State or federal income taxes.

The appraisal value is the sum of these annual net cash flows to the producers discounted back to the present at a rate chosen to fairly represent the alternative uses of capital. The choice of the discount rate is critical as the valuation is greatly affected by it. See Table VI for the effect of various discount rates on our preliminary valuations.

We learned from a discussion with personnel of the Texas petroleum appraisal firm of Prichard & Abbott that

they are proposing a State-wide 18% discount rate this year for valuing reservoirs in Texas. They believe this is a fair rate even though short term lending rates have been higher at the beginning of the year.

We believe any discount rate in the range of 18 to 20 percent to be reasonable for Prudhoe Bay and have picked 19 percent for purposes of forecasting property tax revenue. Here are some of the factors we considered:

1. The State, with advice from Prichard & Abbott, used 18 percent to prepare the 1975 property tax valuation of Prudhoe Bay. Although inflation and interest rates have jumped since then, all of the startup risks of the field and pipeline are behind us now. These factors, thus, tend to cancel out.

2. Large fields typically receive lower rates than small fields because of the inherent diversification coming from multiple wells and collection facilities. The fact that once collected, Prudhoe oil must then flow in a single pipeline a great distance to tidewater effectively eliminates this diversification effect.

3. Alaska's North Slope is a generally hostile environment traditionally accorded higher than average rates to compensate for extraordinary risks.

We believe our valuation estimate of $48.6 billion for the Prudhoe Bay field is sufficiently accurate for use in the context of comparing alternatives to Ch. 21. Errors in the range of $\pm$ 10 percent may still exist due to the diffi-

culties in getting all data on the same basis. Although the State's Producer Benefits Model (P.B.M.) was once on a calendar year basis, it has been converted along with its data to perform fiscal year studies. To establish a January 1 appraisal date, we elected not to reconstruct back to calendar year reporting as would have been theoretically required.

With respect to the other factors most affecting the field's value, such as oil prices, we used the assumptions contained in the P.B.M.

Of the remaining factors that affect the valuation, the most important is the federal windfall profits tax of 1980. Because of the significance of these tax payments, the available calculation of their likely size, provided by the Department of Revenue, was used and the results of the model adjusted accordingly. The federal windfall profits tax is so significant that even the uncertain termination date of the tax may vary the valuation of the field by $7 billion in the first year.

APPENDIX C

A NOTE ON DATA SOURCES

The time available to undertake this analysis did not permit us to develop independent revenue and cost estimates. In part, we relied on published and unofficial working papers supplied by the Department of Revenue. After reviewing their assumptions and procedures, and working with their data continuously for the 10 days, we believe it the best available for this purpose.

Estimates contained in this study are, to the extent possible, consistent with the Department of Revenue's assumptions and forecasts contained in their report "Petroleum Production Revenue Forecast, Quarterly Report, March, 1981." The concerns expressed in that report about the fallibility of "single point" predictions certainly holds for our work as well. At best, these estimates are only a consistent guide for comparison purposes.

Occasionally, we used unpublished data supplied by the Department, but only on a basis consistent with the same March, 1981 assumptions. This was the case for Table I, the figures for which were derived from work sheets supplied by the Petroleum Revenue Division.

Data for Table II was derived from page 9 of the aforementioned March, 1981 quarterly report.

The biggest difficulty that we found with data was to understand and keep consistent the reporting timetables. To

the extent possible, we have attempted to present estimates on a fiscal year basis, when funds will actually accrue to the Treasury. This wasn't always easy. Ch. 21, for example, is on a calendar year basis but provides for quarterly prepayments three out of four of which are actually received in the following fiscal year. Another example is the production tax which taxes monthly oil and gas production. However, the physical production is accounted for by the companies more than a month later which may fall into a different calendar or fiscal year. As a result, estimating a tax receipt often required calculating "pseudo-variables" which create an artificial event that would have occurred if production, liability and payment were all simultaneous. Table III's estimates of effective production tax rates employ this technique to calculate effective rates using production and tax estimates contained in the March, 1981 report.

THE AUTHORS

John R. Messenger is an attorney practicing in Anchorage. From 1973 to 1979, he served successively as an Assistant Attorney General dealing with revenue matters, and as Deputy Commissioner of Revenue.

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FISCAL ANALYSIS OF THE PROPOSED BACKSTOP TAX LEGISLATION

Prepared For

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INTRODUCTION

In our April 15, 1981, report to the Legislature [1/] we (with John Messenger) reviewed the state's options with respect to oil and gas income taxation, and recommended, among other things, that a detailed fiscal analysis be undertaken of the reserves tax backstop, and the oil and gas income tax (ch. 21) revenue it is to protect.

Under contract to, and in association with the Department of Revenue, we now have completed this analysis. The tabular material and extensive accompanying notes in Appendix A, along with the fiscal note to the legislation (SSHB 200), comprise the major outputs of this effort. However, a few specific items which are not immediately obvious are discussed below.

THE USE OF OUR CALCULATIONS

The calculations shown in the appendix have been developed for the purpose of comparing the relative effects of two different taxes. To do this it was necessary to project future prices. In the long run we believe the price trends so projected are reasonable, but they are not a price forecast and should not be used for that purpose.

DEDUCTABILITY OF THE RESERVES TAX

The estimates of the reserves valuation contained in Appendix A have been calculated assuming that no part of the reserves tax will be

actually paid. To the extent that this assumption is relaxed, the fiscal horsepower of the reserves tax will be reduced. These payments reduce the net cash flows from which the valuations are calculated. A sensitivity analysis (not included in the tables) was carried out by us which indicates that the Sadlerochit valuation would be reduced by about 12% if the entire reserves tax were actually paid each year during the reservoir's productive life.

As SSHB 200 is drafted, firms will pay at least one third of the tax in FY 1982, and at least one fourth of it thereafter. If the assessors assume that the reserves tax will remain in place in this form over the life of the field, the fiscal horsepower of the reserves tax will be about three to four percent lower than indicated in our figures.

The reserves tax, to the extent it is actually paid, will be a deduction in the calculation of ch. 21 liabilities. Unless specifically provided for in the legislation, this will reduce ch. 21 liabilities by 9.4 percent of the reserves tax payments. The ch. 21 estimates in the attached tables are calculated without this deduction, but the effect of the deduction is shown in the fiscal note to SSHB 200.

THE "HIGH CASE"

We also did an analysis of the reserves tax's sensitivity to rising prices. We are now of the opinion that the analysis wasn't very

useful, and accordingly, it is not reproduced in the tables, though the data derived from it are shown as the "high case" in the fiscal note to SSHB 200.

The "high case" was driven by the same assumptions as shown in the attached tables except that annual real price increases of 10 percent (instead of 1.5%) were assumed through 1985.

The ch. 21 revenues assumed under these assumptions are meaningful, but the reserves tax figures probably not, at least during the first two fiscal years: it is unlikely that an assessor would assume that the high rate of price escalation would continue, at least at first. More likely a price trend would have to continue for several years before most assessors would feel comfortable projecting it into the future for valuation purposes.

The exercise was not without benefit, since it points up the fact that the reserves tax is likely to be less sensitive to short term price movements, either up or down. To this extent it provides a desirable additional measure of revenue predictability.

DISCOUNT RATE

As we pointed out in our earlier report, [2/] the assessed value of a reserves tax using the capitalized net income approach is very

sensitive to the discount rate.[3] Tables 14 and 15 in the appendix once again show this fact, with a percentage point change in the discount rate resulting in an opposite change in the valuation of roughly $5 billion. The discount rate chosen is obviously important.

Simplifying somewhat, the discount rate can be decomposed into three components to account separately for inflation, risk, and real return. SSHB 200 accounts for inflation by establishing the discount rate as a fixed percentage "above the rate of inflation implicit in the GNP deflator for the five calendar years immediately preceeding the assessment date." Although a number of other inflation proxies could have been chosen, the GNP deflator, as the broadest measure of price changes in wide usage, is as good as any, and better than most indicators.

The legislation specifies that this indicator is to be averaged over five years, which, in our opinion, provides a reasonable approximation of the inflation expectation that might be held by a purchaser of oil and gas reserves.

The actual implicit price deflators for G.N.P. over the past five years are given below.[4]

1976 - 133.8

1977 - 141.6

1978 - 152.1

1979 - 165.5

1980 - 180.1

The inflation rate implicit in these data may be calculated several ways, yielding slightly different results. Assuming continuous compounding of inflation on itself, the rate over the period is 7.4%. [5/]

The fixed percentage added to the inflation rate to take account of risk and real return is a matter of judgment, depending on one's assessment of expected real oil price changes, and a host of other risk factors. Since our earlier report [6/] we have looked into these more carefully, and conclude that from an economic standpoint, any percentage between 1.5 and 13 (in addition to inflation) could plausibly be justified as reasonable.

Overall oil industry return on assets in recent years have averaged around 10%, and according to a study by the American Petroleum Institute, was 10.4% in 1979, i.e., 1.5 percentage points above the inflation rate over the 1979-80 period. [7/]

The Securities and Exchange Commission seems to agree, requiring that oil companies use a 10% discount rate when presenting reserves valuation figures to investors. [8/]

SYMMETRY

Symmetry, is the characteristic which, if it is present, ensures that collections under a reserves tax will bear about the same relation

to income tax collections for all firms. Since we did not make a firm by firm analysis of all companies that would be expected to pay the two taxes, we cannot quantitatively assess the degree to which reserves tax collections will vary symmetrically with ch. 21 liabilities.

We did, however, examine income tax returns of all the major Alaska holder's of oil reserves, and did a correlation analysis in which the reserves valuation that would have been assessed in 1979, had the tax been in effect in that year, was compared with the ch. 21 income tax that was actually paid by those firms. The correlation co-efficient was extremely high, indicating a high degree of symmetry between the tax on oil reserves, and ch. 21 liabilities.

A qualitative analysis of some of the smaller ch. 21 taxpayers indicates that there may be somewhat more variation among them, primarily due to differences in acquisition cost deductions, and pipeline ownership that diverges from reserves holdings. But even here we are confident that variations will, over several years, be minimal with respect to the total amounts being collected.

Finally, the removing of natural gas from the reserves tax base makes the tax generally more symmetric, though it will naturally have the opposite effect with respect to a firm that holds only gas reserves, since it will pay no reserves tax under SSHB 200. Fortunately this anomaly is restricted both in the number of firms affected, and the

dollar amounts of ch. 21 liabilities not backstopped. It could become more significant if gas developments move forward, with substantial gas revenues becoming subject to ch. 21 taxes.

ACKNOWLEDGEMENTS

We were assisted in preparing this analysis by numerous individuals. Foremost among these was John Messenger.

Department of Revenue personnel made indispensable contributions, particularly Commissioner Thomas Williams, Director of Petroleum Revenue Robert Johnson, Jerry Heier, Lou Nelson, and expecially Charles Logsden.

In addition, members of the petroleum property appraisal firm of Pritchard and Abbott assisted us in many ways including performing research on the Cook Inlet and Kuparuk fields.

FOOTNOTES

1/ John R. Messenger, Gregg K. Erickson and Lawrence C. Eppenbach, Alaska Oil and Gas Income Taxation: A Review Of The Options (Alaska State Legislature, April 1981).

2/ Ibid., p. 18.

3/ The valuation may naturally be approximated by an exponential function of the discount rate, e.g.,

$$Y = ae^{bx}$$

where: Y = the assessed value (in billions of dollars);
a = the value of Y when x is zero;
e = the base of natural logs;
b = the exponential slope constant; and
x = the discount rate (expressed here as a percent)

The values of the coefficients of the Sadlerochit (before hardware deductions) are as follows:

Fiscal Year	a	b
81	233.4	-0.06904
82	236.9	-0.06492
83	239.5	-0.06091
84	240.8	-0.05737
85	240.8	-0.05407

In all cases the coefficient of determination (r^2) is greater than .99.

4/ Bureau of Economic Analysis, U.S. Department of Commerce, Survey of Current Business, (March, 1981).

5/ Rate = [LN(180.1/133.8)]/4. The 1980 GNP deflator used is the average of the four quarterly figures given in note 4, supra.

6/ Op. Cit, note 1, supra.

7/ "Journal group's profits jump 67% in '79," Oil and Gas Journal, (Feb. 18, 1980) p. 60.

8/ 17 CFR 210.3.

APPENDIX A

FISCAL ANALYSIS

TABLE 1

SADDLEROCHIT RESERVOIR

OIL PRODUCTION, GAS, AND WATER INJECTION

Fiscal Year	(1) Projected Oil Production (MMB/D)	(2) Gas Injection (MMMcf/D)	(3) Water Injection (MB/D)
1981	1.500	2.156	30.9
82	1.500	1.822	54.2
83	1.500	1.845	87.3
84	1.500	1.836	183.1
85	1.500	1.644	2,288.8
86	1.500	1.595	1,091.7
87	1.500	1.911	1,447.6
88	1.500	1.910	1,566.5
89	1.380	1.894	1,551.1
1990	1.250	1.893	1,356.8
91	1.050	1.893	1,100.6
92	.900	1.800	1,384.9
93	.775	1.831	1,284.1
94	.650	1.895	741.0
95	.560	1.894	832.3
96	.490	1.895	1,024.9
97	.440	1.896	667.8
98	.390	1.875	628.5
99	.355	1.842	455.1
2000	.310	1.795	941.9
01	.270	1.759	199.7
02	.240	1.733	670.3
03	.215	1.675	642.2
04	.190	1.650	615.2
05	.175	1.609	561.9
06	.165	1.564	710.8
07	.155	1.519	363.0
08	.145	1.484	770.7
09	.135	1.443	438.6
2010	.125	1.401	592.4

NOTES TO TABLE 1

(1) The oil production assumption, follows the Case B scenario contained in Three-Dimensional Reservoir Study, Sadlerochit Formation, Prudhoe Bay Field. (March 1980), By H. K. van Poollen and Associates, Inc. However, the variations associated with concentrated owrkovers have been smoothed to produce a flat production function through 1988, and a monotonic decline function thereafter. Production was assumed to cease at the end of FY 2010.

(2) Estimated from the van Poollen study and information from the Alaska Oil and Gas Conservation Commission. Injected gas is roughly 90 percent of associated gas produced.

(3) Assumes source water injection beginning in FY 1985.

TABLE 2

PROJECTED WELL DRILLING AND PRODUCTION SCHEDULE

FISCAL YEAR	(1) NEW WELLS DRILLED OIL PRODUCTION	(2) NEW WELLS DRILLED WATER	(3) WELLS PLUGGED	(4) WELLS SUSPENDED	(5) PRODUCING OIL WELLS	(6) OIL WELL WORK-OVERS	(7) INJECTION WATER WELLS	(8) INJECTION GAS WELLS
1981	112			75	254	13	12	18
82	100			112	329	16	12	18
83	6	12		112	429	32	12	18
84	6	12	2	28	529	53	12	18
85	8	6	2	16	545	68	24	18
86	7		2	5	550	83	42	18
87	6		3	4	555	111	42	18
88			5		560	112	42	18
89			20		540	108	42	18
1990			20		520	104	42	18
91			20		500	100	42	18
92			10		490	98	42	18
93			10		480	96	42	18
94			10		470	94	42	18
95			10		460	92	42	18
96			10		450	90	42	18
97			10		440	88	42	18
98			10		430	86	42	18
99			10		420	84	42	18
2000			10		410	82	42	18
01			12		400	60	40	18
02			12		390	59	38	18
03			12		380	57	36	18
04			12		370	37	34	18
05			12		360	36	32	18
06			12		350	35	30	18
07			12		340	17	28	18
08			12		330	17	26	18
09			12		320	0	24	18
2010			12		310	0	22	18

NOTES TO TABLE 2

To produce the annual oil volumes listed in Table 1, a well drilling, workover, and plugging plan was developed.

(1) New oil wells completed in FY 1981 and FY 1982 are from operator forecasts. Additional wells in FY 1983-87 were added to meet producing oil well requirements.

(2) New water wells estimated to meet total water injection needs.

(3) Well abandonment and plugging forecast were derived from Pritchard and Abbott, Reservoir Valuation Report (1977).

(4) Wells suspended but available in 1981 from current field inventory. Later years are differences between cumulative new wells drilled and new wells operating.

(5) The annual number of producing oil wells was estimated by combining the 1980 field inventory of 232 with operator estimate of planned new wells. The estimates of producing oil wells were developed on a basis generally consistent with the oil well estimates contained in the Petroleum Revenue Division's forecast model, and Pritchard and Abbott's 1977 estimates.

(6) Oil well workover estimates are the same percent of annual producing oil wells as contained in the 1977 Pritchard and Abbott Report.

(7) The number of water injection wells was projected based on the estimated amount of water required to be injected and on an average per well injection capacity of 50 thousand barrels/day.

(8) Gas well number from current field inventory.

TABLE 3

ESTIMATED
SADLEROCHIT OPERATING COSTS
(Millions)

	Values in Constant 1981 Dollars							Current Dollars
FISCAL YEAR	(1) OIL PRODUCTION	(2) GAS PRODUCTION	(3) GAS INJECTION	(4) WATER INJECTION	(5) WELL PLUG&RESTORE	(6) WELL WORKOVER	(7) TOTAL OPERATING	(8) TOTAL OPERATING
1981	147.825	17.673	62.955	1.128	0.	13.000	242.581	242.58
82	147.825	15.045	53.202	1.978	0.	16.000	234.050	255.11
83	147.825	15.330	53.874	3.186	0.	32.000	252.215	299.66
84	147.825	14.812	53.611	6.683	2.000	53.000	277.931	359.93
85	147.825	13.352	48.005	83.541	2.000	68.000	362.723	512.01
86	147.825	12.950	46.574	39.847	2.000	83.000	332.196	511.12
87	147.825	15.520	55.801	52.837	3.000	111.000	385.983	647.33
88	147.825	15.513	55.772	57.177	5.000	112.000	393.287	718.94
89	135.999	15.381	55.305	56.615	20.000	108.000	391.300	779.59
1990	123.188	15.388	55.276	49.523	20.000	104.000	367.375	797.90
91	103.478	15.367	55.276	40.172	20.000	100.000	334.293	791.39
92	88.695	14.578	52.560	50.549	10.000	90.000	306.382	790.60
93	76.376	14.987	53.173	46.870	10.000	96.000	297.406	836.50
94	64.058	15.432	55.334	27.047	10.000	94.000	265.871	815.11
95	55.188	15.396	55.305	30.379	10.000	92.000	258.268	863.06
96	48.290	15.388	55.334	37.409	10.000	90.000	256.421	934.01
97	43.362	15.381	55.363	24.375	10.000	88.000	236.481	938.90
98	38.435	15.206	54.750	22.940	10.000	86.000	227.331	983.81
99	34.985	14.950	53.786	16.611	10.000	84.000	214.332	1011.03
2000	30.551	14.452	52.414	34.379	10.000	82.000	223.796	1150.68
01	26.609	14.264	51.363	7.289	12.000	60.000	171.525	961.30
02	23.652	14.053	50.604	24.466	12.000	59.000	183.775	1122.65
03	21.188	13.571	48.910	23.440	12.000	57.000	176.109	1172.64
04	18.725	13.374	48.180	22.455	12.000	37.000	151.734	1101.27
05	17.246	13.052	46.983	20.509	12.000	36.000	145.790	1153.36
06	16.261	12.680	45.669	25.944	12.000	35.000	147.554	1272.37
07	15.275	12.315	44.355	13.350	12.000	17.000	114.195	1073.34
08	14.290	12.030	43.333	28.131	12.000	17.000	136.784	1298.91
09	13.304	11.702	42.136	16.009	212.000	0.000	295.151	3295.99
2010	12.319	11.359	40.909	21.623	212.000	0.000	298.210	3629.87

NOTES TO TABLE 3

(1) Oil production operating costs are projected at 27¢/barrel, from a 1979 estimate provided by H. K. van Poollen and Associates, Inc., under a contract with the Legislative Affairs Agency and the Division of Minerals and Energy Management. Annual operating expenses = 27¢/barrel * average daily oil production (Col. 1, Table 1) * 365 days.

(2) Gas production costs (the costs of separating and handling the associated gas production) are projected at 2¢/Mcf. This is double the 1¢/Mcf suggested by van Poollen and Associates in 1979, reflecting higher expected gas handling costs. Annual gas production operating expenses = 2¢/Mcf * ave. daily gas production * 365 days. Gas production is roughly 10% greater than the amount of gas injected (Col. 2, Table 1).

(3) Gas injection costs are projected at 8¢/Mcf on the basis of estimates provided by H. K. van Poollen in 1979 (see note 1, above). Gas injection costs = Gas Injection amounts (Col. 2, Table 1) * 8¢/Mcf * 365 days.

(4) Water injection costs, including the variable costs of a source water system, are estimated at 10¢/barrel. This rate falls between the 9¢/barrel estimated by H. K. van Poollen and Associates Inc. in 1979 and the 13¢ to 16¢/barrel estimated by Prichard and Abbott in 1977. Water injection costs = water injection amounts (Col. 3 Table 1) * 10¢/barrel * 365.

(5) Well plugging costs and abandonment costs are projected at $1 million/well, Well plugging costs = $1 million/well * number of well pluggings (Col. 3, Table 2). An additional $400 million (1981 dollars) has been included during the last two years of production for general field restoration work.

(6) Well workover costs are projected at $1 million/workover, somewhat higher than the $795. thousand estimated by Pritchard and Abbott in 1977. Well workover costs = $1 million/workover * number of workovers (Col. 6, Table 2).

(7) Total operating costs = (1) + (2) + (3) + (4) + (5) + (6).

(8) Inflation adjusted operating costs. The rate of inflation is assumed to be constant at 9 percent per year throughout the period. The inflation adjustment assumes simple annual price increases compounded yearly.

TABLE 4

ESTIMATED CAPITAL COSTS
(MILLIONS)

	Values in Constant 1981 Dollars				Current Dollars
Fiscal Year	(1) New Wells	(2) Water Flood & Other	(3) Total	(4) Total Tangible	(5) Total
1981	336	1196	1532	1308	1532
82	300	1680	1980	1780	2158
83	54	1790	1844	1808	2191
84	54	1251	1305	1269	1690
85	42	688	730	702	1030
86	21	0	21	7	32
87	18	0	18	6	30
1988 & later	0	0	0	0	0

NOTES TO TABLE 4

(1) New well costs are projected at $3 million/well. New well costs = (Col. 1 Table 2, + Col. 2, Table 2) * $3 million.

(2) Source water gathering, treatment, and injection facilities account for most of these capital costs.

(3) Total = (Col. 1) + (Col. 2).

(4) Total Tangible costs = total costs less intangible drilling costs. We estimate that 1/3 the cost of drilling each well to represent tangible property such as the well casing and fixtures. Other capital costs are assumed to be 100% tangible.

(5) Col. 3 * inflation adjustment. The inflation adjustment assumes simple annual price increases at 9 percent per year commencing in Fiscal Year 82.

TABLE 5

SADLEROCHIT OIL ROYALTY AND PRODUCTION TAX ESTIMATES

Fiscal Years	(1) Average Wellhead Price/B	(2) Gross Returns (Millions)	(3) Cleaning Costs/B	(4) Royalty Oil Value (Millions)	(5) Per Well Production MB/D	(6) Economic Limit Factors	(7) Production Tax Payments (Millions)
1981	$ 19.76	10818.60	48.5	1319.13	5.906	.9245	1075.83
82	26.31	14404.73	58.5	1760.55	4.559	.9011	1395.72
83	30.58	16742.55	65.3	2048.13	3.497	.8718	1569.30
84	33.79	18500.03	71.2	2263.78	2.836	.8428	1676.28
85	37.33	20438.18	77.6	2501.66	2.752	.8381	1841.49
86	41.25	22584.38	84.6	2765.15	2.727	.8367	2031.39
87	45.58	24955.05	92.2	3056.20	2.703	.8353	2240.78
88	50.37	27577.58	100.5	3378.42	2.679	.8338	2471.71
89	55.66	28035.94	109.6	3435.49	2.556	.8261	2489.50
1990	61.50	28059.38	119.4	3439.33	2.404	.8155	2459.51
91	67.96	26045.67	130.2	3193.33	2.100	.7899	2211.26
92	75.10	24670.35	141.9	3025.53	1.837	.7612	2018.31
93	82.98	23472.92	154.7	2879.42	1.615	.7302	1842.08
94	91.70	21755.83	168.6	2669.48	1.383	.6879	1608.36
95	101.33	20711.85	183.8	2542.02	1.217	.6485	1443.43
96	111.96	20024.05	200.3	2458.23	1.089	.6108	1314.33
97	123.72	19846.43	218.3	2439.86	1.000	.5714	1237.09
98	136.71	19460.67	238.0	2390.23	.907	.5409	1131.09
99	151.07	19574.90	257.4	2404.85	.845	.5112	1075.22
2000	166.93	18888.13	282.8	2321.02	.756	.4614	936.40
01	184.46	18178.53	308.2	2234.35	.675	.4069	794.55
02	203.82	17854.63	335.9	2195.05	.615	.3593	689.24
03	225.22	17674.14	366.2	2173.35	.566	.3150	598.14
04	248.87	17259.13	399.1	2122.79	.514	.2617	425.24
05	275.01	17566.26	435.1	2161.04	.486	.2300	434.04
06	303.88	18301.17	474.2	2251.95	.471	.2122	417.19
07	335.79	18997.32	516.9	2338.11	.456	.1938	395.50
08	371.05	19637.82	563.4	2417.46	.439	.1721	363.04
09	410.01	20203.24	614.1	2487.58	.422	.1498	325.09
2010	453.06	20670.85	669.4	2545.69	.402	.1227	272.44

NOTES TO TABLE 5

(1) This is the average effective wellhead price for the 12 month fiscal year beginning each July 1. For FY 1981 the wellhead price was estimated by examining the actual monthly prices for 9 months and estimating the 4th quarter. Fiscal year 1981 prices reflect the impact of oil price controls during the first half of the year. For FY 1982 and beyond we began by assuming a July 1, 1981, wellhead price of $25.00 per barrel (about the current price) and a real price increase of 1 1/2% per year. In addition, we assumed the FY 1983 average wellhead would be adjusted upward by $1.50 due to an expected decrease in the TAP's tariff and that this adjustment would become part of the wellhead price base. Finally, we assumed that inflation would continue at a rate of 9% per year (simple compounding) throughout the period.

(2) Gross returns = (Col. 1) * (Col. 1, Table 1) * 365 days).

(3) This charge for cleaning state royalty oil to make it pipeline ready is set out in the settlement agreement providing for 42¢/barrel, inflated after 1980 by the producer price index.

(4) Royalty oil value equals 12.5% of gross returns (Col. 2) less cleaning charges,.which equal (Col. 3) * (Col. 1, Table 1) * 365.

(5) Average per well daily oil production rates equals daily oil production divided by the number of wells. (Col. 5) = (Col. 2 Table 1)/(Col. 5 Table 2).

(6) The economic limit factors are calculated in the manner set out in AS 43.55, using a pel value of 300B/D, and the average production rates in Col. 5.

(7) (Col. 7) = [(Col. 2) - (Col. 4)] * (Col. 6) * .1225.

TABLE 6

SADLEROCHIT PROPERTY TAX ESTIMATES
(MILLIONS OF DOLLARS)

Fiscal Year	(1) Forecast Tangible Capital Investment	(2) Depreciation Factors	(3) Tax Base (Jan 1) Appraisal	(4) Tax @ 20 Mill Rate
81	-	-	(Actual)3758.25	75.17
82	1367	.9600	5299.49	105.99
83	2031	.9583	7567.04	151.34
84	2253	.9565	10142.56	202.85
85	1727	.9545	12279.81	245.60
86	1043	.9524	13790.85	275.82
87	11	.9500	14291.78	285.84
88	11	.9474	14768.78	295.38
89		.9444	15203.64	304.07
90		.9412	15597.14	311.94
91		.9375	15938.33	318.77
92		.9333	16214.59	324.29
93		.9286	16411.48	328.23
94		.9231	16512.48	330.25
95		.9167	16498.72	329.97
96		.9091	16348.73	326.97
97		.9000	16038.10	320.76
98		.8889	15539.14	310.78
99		.8750	14820.46	296.41
2000		.8751	13846.54	276.93
01		.8333	12577.27	251.55
02		.8000	10967.38	219.35
03		.7500	8965.84	179.32
04		.6667	6515.17	130.30
05		.5000	3550.77	71.02
06		.0000	0	0
07			0	0
08			0	0
09			0	0
2010			0	0

NOTES TO TABLE 6

To estimate payments of the ad valorum tax on production property (the 20 mill "hardware tax") we simulated Dept. of Revenue appraisal practices. First, replacement value was determined by appreciating the prior years tax base at an assumed inflation rate of 9%. This new base was then depreciated over the remaining useful life of the field which was assumed to be 25 years in FY 1981. Finally, any current year tangible cost outlays were added to the adjusted property tax base.

(1) From Col. 4, Table 4, adjusted for inflation at 9%.

(2) Factors represent one minus incremental depreciation rates - (1-1/25), (1-1/24), (1-1/23) . . .

(3) Tax base calculated as described above. FY 1981 amount is the actual appraised value by the Petroleum Revenue Division, Department of Revenue. Zero amounts shown in years 2006-2010 are a product of the assumed 25 year useful life. Small actual amounts would exist if production were to continue to the year 2010.

(4) Tax Revenue Estimate assumes 20 mill tax rate throughout period. (Col. 4) = (Col. 3) * .02.

TABLE 7

SADLEROCHIT WINDFALL TAX ESTIMATES

Fiscal Year	(1) WORKING INTEREST PRODUCTION (Millions of Barrels)	(2) WELLHEAD PRICE (Dollars per Barrel)	(3) AVERAGE BASE PRICE (Dollars per Barrel)	(4) NON-WINDFALL GROSS (Millions of Dollars)	(5) GROSS WINDFALL (Millions of Dollars)
1981	479.6	19.76	13.69	6565.72	2911.18
82	479.6	26.31	14.92	7155.63	5462.65
83	479.6	30.58	16.65	7982.94	6683.23
84	479.6	33.79	19.23	9222.71	6982.97
85	479.6	37.33	20.82	9985.27	7918.20
86	479.6	41.25	22.56	10819.78	8963.72
87	479.6	45.58	24.46	11731.02	10129.15
88	479.6	50.37	26.53	12723.79	11433.66
89	440.7	55.66	28.78	13802.89	10728.70
1990	399.2	61.50	31.23	14977.91	9574.12
91	335.3	67.96	33.91	16263.28	6526.47

Fiscal Year	(6) PRODUCTION TAX ON WINDFALL (Millions of Dollars)	(7) NET WINDFALL (Millions of Dollars)	(8) PHASE-OUT FACTOR	(9) W.P.T. (Millions of Dollars)
1981	329.69	2581.49	1.000	1807.04
82	602.99	4859.66	1.000	3401.76
83	713.74	5969.49	1.000	4178.64
84	720.94	6262.03	1.000	4383.42
85	812.94	7105.26	1.000	4973.63
86	918.74	8044.98	1.000	5631.49
87	1036.46	9092.69	1.000	6364.88
88	1167.84	10265.82	.910	6539.33
89	1085.71	9642.99	.450	3037.54
90	956.44	8617.68	.200	1206.48

NOTES TO TABLE 7

The 1980 Federal Windfall Profits Tax placed Sadlerochit oil in the highest tax category (70%) but provided for favorable treatment of reductions in TAP's pipeline tariff.

(1) Working interest production is the non royalty share of oil production. (Col. 1) = (Col. 1, Table 1) * 365 * 7/8.

(2) Wellhead price estimates from Col. 1, Table 5.

(3) Average base price estimates are calculated as set forth in the law. Beginning with a May, 1979, price control ceiling value of $12.70 less 21¢ this amount is inflated by the GNP deflator lagged 2 quarters. After 1981, inflation is projected at a 9% simple annual rate. In addition, a TAP's tariff adjustment is added to this base assuming a tariff decrease of $1.50 per barrel mid fiscal year 1983. This provides a one quarter rate adjustment during FY 83 (37.5¢) and thereafter $1.50.

(4) Non-windfall gross equals the average base price times production. This amount plus any production taxes paid on the windfall is exempt from the tax. (Col. 4) = (Col. 1) * (Col. 3).

(5) Gross windfall equals total working interest production (excludes state royalty share). (Col. 5) = (Col. 1) * [(Col. 2) - (Col. 4)].

(6) The production tax on the windfall portion is calculated assuming a 12.25% tax rate and economic limit factors already estimated. (Col. 6) = (Col. 5) * 12.25% * (Col. 6, Table 5).

(7) Net windfall amounts equal the gross windfall less production taxes, up to 15%, paid on the windfall portion. (Col. 7) = (Col. 5) - (Col. 6).

(8) The windfall profits tax is due to phase out at 3% per month when total collections reach $227.3 billion, but not before January 1988. Phase out factors assume the windfall profits tax will collect $227.3 Billion on or before January, 1988.

(9) The windfall profits tax payments equals 70% of net windfall adjusted for phase out. (Col. 9) = (Col. 7) * (Col. 8) * .7.

TABLE 8

SADLEROCHIT RESERVOIR VALUE IN ESTIMATED
(MILLIONS OF DOLLARS)

Fiscal Year	(1) PRODUCERS GROSS REVENUE	(2) TOTAL OPERATING EXPENSES	(3) TOTAL CAPITAL OUTLAY	(4) OIL PRODUCTION TAX	(5) AD VALORUM PROPERTY TAX
1981	9499.47	242.58	1532	1075.83	75.17
82	12644.18	255.11	2158	1395.72	105.99
83	14694.42	299.66	2191	1569.30	151.34
84	16236.25	359.93	1690	1676.28	202.85
85	17936.53	512.01	1030	1841.49	243.60
86	19819.23	511.12	32	2031.39	275.82
87	21898.77	647.33	30	2240.78	285.84
88	24199.16	718.94		2471.71	295.38
89	24600.45	779.69		2489.50	304.07
1990	24620.05	797.90		2459.51	311.94
91	22852.34	791.39		2211.26	318.77
92	21644.82	790.50		2018.31	324.29
93	20593.55	836.50		1842.08	328.23
94	19086.35	815.11		1608.36	330.25
95	18169.83	863.06		1443.43	329.97
96	17565.82	934.01		1314.33	326.97
97	17429.57	938.90		1237.09	320.76
98	17070.44	983.81		1131.09	310.78
99	17170.05	1011.03		1075.22	296.41
2000	16567.11	1150.58		936.40	276.93
01	15944.18	961.30		794.55	251.55
02	15659.58	1122.65		689.24	219.35
03	15500.79	1172.64		598.14	179.32
04	15136.37	1101.27		485.24	130.30
05	15405.22	1153.36		434.04	71.02
06	16049.22	1272.37		417.19	
07	16659.21	1073.34		395.50	
08	17220.36	1298.91		363.04	
09	17715.66	3295.99		325.09	
2010	18125.18	3629.87		272.44	

TABLE 8 CONT'D.

Fiscal Year	(6) WINDFALL PROFITS TAX	(7) TOTAL NET CASH FLOW	(8) TIME PERIOD TO JULY, 1981 (Years)	(9) NET PRESENT VALUE 19% DISCOUNT RATE
1981	1807.04	-	-	-
82	3401.76	5327.60	.5	4883.80
83	4178.64	6304.48	1.5	4856.56
84	4383.42	7923.77	2.5	5129.38
85	4973.63	9333.80	3.5	5077.43
86	5631.49	11337.41	4.5	5182.66
87	6364.88	12329.94	5.5	4736.45
88	6539.33	14173.80	6.5	4575.42
89	3037.54	17999.65	7.5	4880.01
1990	1206.48	19844.22	8.5	4523.61
91	20.63	19510.29	9.5	3737.38
92		18511.62	10.5	2979.90
93		17586.74	11.5	2379.00
94		16332.63	12.5	1856.60
95		15533.37	13.5	1483.82
96		14990.51	14.5	1203.33
97		14932.82	15.5	1007.31
98		14544.76	16.5	830.15
99		14787.39	17.5	704.40
2000		14203.10	18.5	568.54
01		13936.78	19.5	468.81
02		13628.34	20.5	285.24
03		13550.69	21.5	321.89
04		13419.56	22.5	267.87
05		13746.80	23.5	230.59
06		14359.66	24.5	202.42
07		15190.37	25.5	179.94
08		15558.41	26.5	254.87
09		14094.58	27.5	117.90
2010		14222.87	28.5	99.98
			To July 1, 1981 =	63,025.29

NOTES TO TABLE 8

NOTE: This valuation simulates the action of appraisors by calculating the value of the Sadlerochit field using the discounted income method. It assumes that any tax levied on this valuation base would not be paid because of offsetting credits. Valuation totals include the value of plant and equipment in the field already subject to an ad valorum property tax.

(1) Producers gross revenue is equal to the gross value of production less the net state royalty share. In these estimates wellhead oil prices are assumed to increase 1.5% per year for real price growth and 9% per year for inflation throughout the period. (Col. 1) = (Col. 2, Table 5) - (Col. 4, Table 5).

(2) Total Operating Expenses from Col. 8, Table 3.

(3) Total Capital Outlay from Col. 5, Table 4.

(4) Oil Production Tax from Col. 7, Table 5.

(5) Ad valorum property tax ("hardware") from Col. 4, Table 6.

(6) Windfall profits tax from Col. 9, Table 7.

(7) Total net cash flow equals the producers gross revenue less all deductions (Note: Income taxes are not deductible and minor amounts such as conservation taxes have also been ignored). Fiscal year 1981 cash flows have also been excluded as they occur prior to valuation date. (Col. 7) = (Col. 1) - (Col. 2) - (Col. 3) - (Col. 4) - (Col. 5) - (Col. 6).

(8) Time is measured from the middle of the indicated fiscal year to July 1, 1981, the appraisal date. For later year valuations this Col. is moved downward, seriatum.

(9) Net present values are calculated using a 19% discount rate and simple annual discounting, i.e., (Col. 7)/[1.19 exp. (Col. 8)]. This is consistant with usual appraisal practices.

The valuation as of July, 1981, is the sum of the present values of cash flows listed in Col. 9. Valuation in subsequent years assumes that all judgments regarding field development and price increases remain unchanged. They are then calculated by excluding periods prior to the new valuation date and discounting the remaining cash flows in Col. 7 over the time period calculated to that date. The results of these calculations are shown in Table 14.

TABLE 9

SADLEROCHIT STATE INCOME TAX ESTIMATES
(MILLIONS OF DOLLARS)

Fiscal Year	(1) STATE ROYALTY SHARE	(2) PRODUCTION CONSERV. TAX	(3) AD VALORUM PROPERTY TAX	(4) TOTAL OPERATING COSTS	(5) DEPRECIATION COSTS	(6) AQUISITION COSTS EXPENSE	(7) INTEREST EXPENSE
1981	1319.13	1076.51	75.17	242.58	222.25	123.08	199.62
1982	1760.55	1396.40	105.99	255.11	333.14	141.54	220.58
1983	2048.13	1570.48	151.34	299.66	496.79	162.77	243.74
1984	2263.78	1676.96	202.85	359.93	684.27	187.19	269.33
1985	2501.66	1842.17	245.60	512.01	841.95	215.27	297.61

Fiscal Year	(8) EXPLORATION COSTS	(9) ADMINISTRA-TIVE COSTS	(10) TOTAL DEDUCTIONS	(11) GROSS RETURNS	(12) TOTAL TAXABLE INCOME	(13) TOTAL TAX LIABILITY
1981	60.71	65.70	3384.75	10818.60	7433.85	698.78
1982	69.81	71.61	4354.73	14404.73	10050.00	944.70
1983	80.29	78.06	5131.26	16742.55	11611.29	1091.46
1984	92.33	85.08	5821.73	18500.03	12678.30	1191.76
1985	106.18	92.74	6655.18	20438.18	13783.00	1295.60