# COMPARISON OF CRUDE OIL TAX PROPOSALS

(Prepared by Minority Counsel, Senate Finance Committee)

| | SENATE FINANCE COMMITTEE | HOUSE BILL | ADMINISTRATION |
|---|---|---|---|
| **LOWER TIER OIL** | 75 percent of different between base price of $6.00 (adjusted for inflation) and the selling price. Applies to released lower tier oil that is below 1.5 percent decline curve. Tax phases out by 6/84 | Same except tax rate is 60 percent | Tax rate is 50 percent & decline curve is 2 percent |
| **UPPER TIER OIL** | 60 percent of difference between base price of $13.00 (adjusted for inflation) and selling price. Tax phases out between 1986 & 1990 | Same | Same except tax rate is 50 percent |
| **NEWLY DISCOVERED OIL** | Total exemption for oil discovered on a property which had no production in 1978 (DOE pricing definition) | 50 percent of the difference between a base price of $17.00 per barrel (adjusted for inflation plus 2 percent per year) and the selling price up to $26.00 per barrel (adjusted for inflation plus 2 percent per year) and the selling price. Tax is permanent. Restrictive definition | 50 percent of difference between $16 bbl (adjusted for inflation) & the selling price. Tax is permanent |
| **TERTIARY OIL** | Total exemption for incremental tertiary production. Producer can use actual decline rate for post 1978 months before project starts | 50 percent of difference between $17.00 (adjusted for inflation plus 2 percent & selling price). Tax terminates on 12/31/90. Applies oil above a level determined by a decline curve of 1 percent a month until project starts. 2.5 percent per month once project starts | Same as newly discovered; apply only to oil produced by enhanced recovery on case by case basis |
| **ALASKA NORTH SLOPE** | Taxes Sadlerochit oil in as Upper Tier Oil (60 percent rate with $13 base price) modified pipeline tariff adjustment | 50 percent of difference between a base price of $7.50 (adjusted for inflation and the selling price). Applies to oil from Sadlerochit Reservoir. Adjustment for value of pipeline tariff | Originally no tax but later modified to tax in Tier 2 |
| **STRIPPER OIL** | Exempts first 1,000 bbls/day produced by independent producer & royalty holder. Other stripper taxed at 60 percent tax rate on the difference of $16 base price & selling price | Taxed at 60 percent tax rate on the difference of $16 base price & selling price | Same as House bill but tax rate is 50 percent |
| **MARGINAL OIL** (deep stripper) | Taxed in Tier 2: 60 percent of difference between $13 and selling price. Tax phases out between 1986 & 1990; definition includes high water cut oil | Same as Finance Committee but excludes high water cut oil | Same as House but rate is 50 percent |
| **HEAVY OIL** | Exempts oil with a specific gravity of 16 degrees or less | Heavy oil treated no differently from other oil | Recommended exemption after the House bill passed |

**OTHER CHANGES FROM HOUSE BILL**

- Senate Finance Committee reduces net income limitation from 100 percent of net income from property to 50 percent
- Allows severance tax deduction for all oil including increases after March 1979 if applies to entire oil price
- Allows longer payment period of tax for independent refiners
- Entire tax phases out volumetrically at 3 percent per month when revenues collected reach 90 percent of anticipated total

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## *Former DOE Undersecretary Myers Heads Jacobs Engineering Group*

PASADENA, Calif. — Former [illegible] Undersecretary of Energy [illegible] Responsible during his tenure for all basic and applied research [illegible]

## Is Newfoundland Drill Profitable?

ST. JOHN'S, Newfoundland — Discovery of a reservoir of close to 500 million barrels will be necessary before oil production off the Newfoundland coast becomes worthwhile, Mobil Oil Canada Ltd. [illegible] talk to Chuf

# DISCUSSION OF THE OIL AND GAS INCOME TAX LAWSUIT

The Oil and Gas Income Tax Act, AS 43.21, taxes oil and gas companies at the same rate as other corporations. However, it provides for a different method of determining the tax base (i.e., taxable income) from the regular corporate income tax. AS 43.21 combines the two basic approaches to the taxation of income of multistate corporations. On one hand, it incorporates "separate accounting," in which the income and expenses of a company's in-state activities are separately determined without regard to the corporation's out-of-state business, as if the in-state business were the only business the company engages in. This approach is applied to determine an oil company's taxable income from oil and gas production or pipeline transportation. On the other hand, AS 43.21 also utilizes the "apportionment" approach, whereby income from the corporation's worldwide activities is apportioned to in-state activities by applying a formula. Apportionment is used in AS 43.21 to determine a taxpayer's in-state income from sources other than oil and gas production and pipeline transportation.

The litigation over AS 43.21 questions whether it violates the due process clause, the equal protection clause and the commerce clause of the U.S. Constitution, as well as provisions of the Outer Continental Shelf Lands Act that limit state taxation of the OCS. The original case, brought by Atlantic Richfield and Sohio, presents eight counts in its cause of action. The State subsequently presented the same eight counts, but expressed in the negative, in a second lawsuit against all other taxpayers under AS 43.21 who filed and paid under protest. The eight counts are:

1. Duplicative taxation. Count I of the Arco suit alleges that AS 43.21 results in impermissible duplicative taxation by imposing an unapportioned tax on interstate income. In other words, it alleges that separate accounting for production income and pipeline income is unconstitutional. The plaintiffs point out that other states which use an apportionment formula might require the plaintiffs to include the Alaska-taxed income as part of the total apportionable income for purposes of those other states' income taxes. The combined result, the companies argue, could be that more than 100% of their income ends up being taxed by the states.

A case is currently pending before the U.S. Supreme Court, Exxon Corp. v. Wisconsin Dept. of Revenue, which may considerably affect the outcome of Count I in the Arco case. The issue there is whether separate accounting is constitutionally required instead of apportionment in cases where a corporation has functionally separate operations (i.e., exploration, production and marketing) and some occur within the taxing jurisdiction and others are entirely outside it. If the Court requires separate accounting in Exxon, the State's position on Count I will be strengthened. If the Court upholds apportionment, then Exxon could seriously weaken our position, but not necessarily so; the exact effect would depend on the Court's reasoning and the language used in reaching its decision. The case is expected to be decided by the end of June.

Besides the basic question in Count I as to whether separate accounting is permissible in AS 43.21, there are also some issues of duplicative taxation in the application of the apportionment formula embodied in AS 43.21.040 for "other" income. For instance, although production and pipeline income earned in Alaska is already fully recognized under the separate accounting provisions, the income from similar activities occurring wholly outside Alaska is nevertheless included in the worldwide "pie" of income to be divided under apportionment. Similarly, a company engaged only in production in Alaska could still be subjected to apportionment of its "other" worldwide income simply because it charters tankers from a third party to ship its oil out of the state. Both of these problems would be dealt with in the Administration's "technical amendments" bill (HB 963), at a cost to the State of less than a million dollars in FY 81.

While these last two issues have relatively small dollars-and-cents consequences themselves, losing them in court could be serious. The legislative history of AS 43.21 shows that all antecedent versions of the bill in 1978 had severability clauses. The final version of AS 43.21 did not. One could argue from this fact that the Legislature wanted the entire Act to stand or fall together. If the courts agreed, then losing even these "minor" issues would lead to the downfall of the entire tax. The possibility of this outcome is, of course, significantly reduced by the general severability clause in AS 01.10.030, but not absolutely eliminated.

2. Equal protection. The second count in the Arco case alleges that AS 43.21 discriminates against interstate commerce and violates equal protection and due process. This is based on a comparison of the tax treatment of oil and gas companies under AS 43.21 vis a vis their previous treatment under AS 43.20, which is still afforded to all other corporations. This issue could not be entirely resolved, legislatively or by regulation, except by repealing AS 43.21 and going back to AS 43.20 as the tax for the oil industry. However, there are legislative and regulatory actions that could be taken that would eliminate differences between AS 43.20 and AS 43.21 that the industry regards as being the

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most important. These relate to accelerated depreciation and the expensing of intangible drilling costs for wells in Alaska.

Depreciation is currently allowed for production equipment on a unit-of-production basis; that is, each barrel produced has the same amount of depreciation associated with it. This is a form of accelerated depreciation since production rates over the life of a field are greatest in the early years and fall off in later years. By regulation the Department of Revenue could authorize other forms of accelerated depreciation, such as those used for the IRS.

Depreciation for pipelines is strictly on a straight-line basis. This is because taxable pipeline income is tied by statute to the pipeline's net income as regulated by the Federal Energy Regulatory Commission (FERC). FERC uses straight-line depreciation.

Allowing accelerated depreciation does not affect the total amount of depreciation allowed as a deduction, it changes the timing. The effect is to reduce the tax liability in the early years and make up for it in later years. In the case of tax year 1980 (one quarter paid in FY80 and three quarters in FY81), the tax deferral from accelerated depreciation of production equipment would be \$25 million. For pipelines it would be \$36 million.

Intangible drilling costs are now required to be capitalized and depreciated on a unit-of-production basis as production equipment. Expensing such costs is the fastest possible form of accelerated depreciation. If only new drilling could be expensed, the tax deferral would be about \$72 million for FY81.

3. Excessive, discriminatory taxation. In Count III of the complaint, plaintiffs alleged that the amount of taxes imposed by AS 43.21 bears no fair relation to services provided by the State. In doing so, they pointed out the large anticipated surplus of funds coming into the treasury, the high proportion of state revenues already being derived from sources other than AS 43.21, and the large amount of taxes that they will have to pay in addition under the oil and gas income tax.

4. Modification of leases. Count IV of the complaint alleges that Alaska, by enacting AS 43.21, unilaterally and unconstitutionally modified its oil and gas leases. This seems almost frivolous in light of the Alaska Constitution's specific prohibition against contracting away the State's taxation power; no lease provision could have abridged this power.

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5. OCS income. The Outer Continental Shelf Lands Act forbids the states from taxing activites beyond their three-mile limits. Count V of the Arco/Sohio complaint alleges that AS 43.21.040, by including Alaska OCS property and payrolls in the formula for apportioning worldwide "other" income, violates this federal prohibition and is thus pre-empted under the supremacy clause of the U.S. Constitution. The dollars at stake in Count V are comparatively small at present, under $5 million a year. But this would change if there is significant new activity in the OCS of Alaska. Also, an adverse ruling here could bear on the nonseverability issue.

6. Retroactivity. Count VI of the lawsuit raises a technical question as to procedure in the enactment of AS 43.21. Plaintiffs allege that the Act, which became law on July 6, 1978, cannot be made retroactive to the first of that year without the concurrence of two-thirds of the membership of each house of the Legislature. They further allege that such concurrence was not given by the Senate. This issue should, at most, affect receipts under AS 43.21 for only part of the 1978 tax year.

7. Regulations. The Department adopted regulations requiring payments of estimated taxes in installments in advance of the final due date for each year. Count VII alleges that the statutory authorization for "installments" means the Department could only adopt regulations allowing payments after the due date. The effect of losing this count would not be a loss in tax receipts finally collected, but only in the cash-flow timing of those receipts and the lost interest income from the prepayments. The lost interest would be $45.8 million a year if the annual tax receipts are $500 million.

8. Taxation of out-of-state income. Count VIII alleges that AS 43.21 taxes out-of-state income having no connection with Alaska. To some extent this repeats the Count I challenge to aspects of the apportionment formula. Besides being a sort of "catch all," this last count could also refer to AS 43.21.010, which subjects to the tax all corporations deriving income from the production of oil and gas from a lease or property "in or directly associated with the state". The underlined portion refers to leases in the OCS whose operations are supported from a base or staging area onshore in Alaska. There is a real constitutional "due process" question as to whether Alaska may tax a corporation having no contact with Alaska other than deriving income from a lease or property "directly associated" with the state. In addition, the provisions of the OCS Lands Act could apply to bar such taxation. HB 963 would eliminate this issue. Since there are at present no such corporations, the present revenue effect is nil. Again, a loss here could trigger far greater effects if nonseverability in fact applies to the Act.

SETTLEMENT DISCUSSIONS
IN THE OIL AND GAS INCOME TAX LAWSUIT

In the course of administering AS 43.21, the Department of Revenue has had to adopt a considerable number (over 30 pages worth in the Administrative Code) of fairly technical, detailed regulations to clarify and interpret the Act. In order to adopt appropriate and workable regulations covering such complex and arcane matters as the leveraged leasing of oil tankers, there was considerable dialogue and discussion, both at hearings and in conferences, between the Department and various affected oil companies.

As the full range of policy considerations relating to the successful implementation of the tax was discussed, certain regulatory actions appeared which, in conjunction with some legislative amendments, presented a good promise of being a foundation for a settlement by which the basic validity of the tax would be acknowledged, while reserving for litigation a few narrow issues about the particulars of the application of the tax. The ongoing litigation of those issues would therefore not jeopardize the tax itself, nor would their adjudication one way or the other put major sums of money at risk.

These legislative and regulatory actions do not fall neatly into the categories of issues presented in the various counts given by Arco and Sohio in their lawsuit. In fact, a number of the actions do not even tie directly into any one count. In some cases, the proposed changes could be justified just on the basis of policy considerations, apart from any settlement possibilities. In this group of independently justifiable actions are:

1. The technical amendments proposed in HB 963. Reasons for them are given in Governor Hammond's transmittal letter. Their combined revenue effects are about $5 million a year.

2. Allow current amortization of estimated costs of terminating production operations, removing field facilities and restoring the site. There would be a "settling up" when these had happened to account for any over- or under-amortization. Reasons for this are: A) termination costs may be carried back only three years, which may not allow for them to be fully recognized; and B) this is already allowed in the case of pipelines, because of current FERC rulings. The revenue impact would be about $2 million a year currently.

Less clearly justifiable would be the elimination of the present limitations on interest expense and overhead costs that may be deducted against production income. It would be advisable in such a case to grant the Department clear authority to set aside undue charges for these items, especially if they result from intracorporate or less-than-arms-length transactions. With such safeguards, the present revenue effect would be about $3,500,000 a year.

The big dollars-and-cents issue in the settlement discussion was accelerated depreciation. This is really a tax deferral since the total amount of depreciation ultimately taken does not change, regardless of whether the depreciation is straight-line or accelerated. For tax year 1980, it would amount to $61 million -- $25 million for production equipment and $35 million for pipelines. Of course, interest would be lost on the money until it is recovered, and the payback in later years would be in dollars of reduced buying power.

Intangible drilling costs are merely an aspect of accelerated depreciation. Right now they are capitalized and depreciated on the same basis as production equipment. Allowing them to be expensed (i.e., fully deducted as they are incurred) is simply allowing the ultimate in accelerated depreciation. As with pipelines and production equipment, the tax loss now would be recovered eventually through reduced deductions later in the life of the field. But the impact today is still some $72 million for FY81, not counting forgone interest.

The discussions of these possibilities indicated that, in exchange for these considerations, the oil companies would dismiss the present lawsuit except for the issues regarding OCS and the use of "book" income for apportionment instead of taxable income as reported to IRS. The settlement would not extend to any future developments in federal law, either judicial or legislative, that would impair or annul the State's method of taxing income. Also they would reserve the right to challenge new regulations or interpretations as may arise which are not subjects of the present litigation.

# THE ROLE OF THE WINDFALL PROFITS TAX IN THE OIL AND GAS INCOME TAX

The windfall profits tax is not recognized under AS 43.21 as an allowable deduction against production income. At present this has not become an additional basis for the oil companies' challenge to the oil and gas income tax, but it surely will be.

In thinking about the windfall profits tax, it is important to remember that it is not necessary to settle the lawsuit in order to deal with the windfall profits tax. It is separable from the settlement considerations. However, settlement is most unlikely if there is nothing done about the windfall profits tax.

The revenue implications of the windfall profits tax are far greater than the combined effects of all the other items involved in coming up with a settlement. In FY81 alone, the effect is $142.5 million; in FY82, another $378.4 million. By FY85 it will be almost $600 million a year.

In all settlement discussions through January of this year (when they were broken off), the windfall profits tax was recognized as a major factor for any settlement, but it was a subject whose discussion was postponed until Congress actually passed such a tax and we could see exactly what it was.

Oil Taxes

Royalty

Severence

Property

Income

| | | |
|---|---|---|
| Petroleum Revenue Division<br>2..., E. 9th Ave.<br>Anchorage, Ak., 99501 | Alaska Department of Revenue<br>Oil and Gas Corporate<br>Income Tax Return | Employer Federal Identification Number: |
| This Return is due on or before the date specified in Regulation 15 AAC 12.700. | (Please Type or Print)<br>Name<br>Number and Street<br>City State Zip Code | This Return is for the Tax Year Ended: __/__/__<br>See Regulation 15 AAC 12.820. |

A complete copy of the following reports must be attached to this Return when filed: (a) Annual financial report to stockholders; (b) Federal Energy Regulatory Commission Form P, reporting Alaska oil pipeline activities only; (c) Alaska Public Utilities Commission Form APUC 2, reporting natural gas activities in Alaska (only). All questions and requests for information on page 2 of this Return must be answered.

## Schedule A - Computation of Tentative Tax

1. Taxable Production Income (Loss) - Schedule B ....................
2. Taxable Oil Pipeline Income (Loss) - Schedule C ....................
3. Taxable Gas Pipeline Income (Loss) - Schedule D ....................
4. Taxable Apportioned Income (Loss) - Schedule E ....................
5. Total, lines 1, 2, 3 and 4 (If less than zero enter -0- here and on line 7)....................
6. Less: Net Loss Carryover(s)/Carryback(s) - Schedule F ....................
7. Total Taxable Income (Loss) ....................
8. Surtax Exemption. (See Sections 1561 and 1563 of the Internal Revenue Code) ....
9. Line 7 less line 8 - (If less than zero enter -0-)....................
10. Income Tax Computation:
    (a) 5.4% of line 7 (If less than zero enter -0-) ....................
    (b) 4.0% of line 9 (If less than zero enter -0-) ....................
    (c) Total, lines 10(a) and (b) ....................
11. Estimated Tax Payments: Date Amount
    (a) First Quarter Estimated Payment ....................
    (b) Second Quarter Estimated Payment ....................
    (c) Third Quarter Estimated Payment ....................
    (d) Fourth Quarter Estimated Payment ....................
    (e) If an Extension has been granted for this Return, the amount paid at the time of Extension ........
12. Other Payments (Specify: ).
13. Total Prepayments. Add lines 11(a),(b),(c),(d),(e), and line 12 ....................
14. Unpaid or Overpaid Tentative Tax. Line 10(c) less line 13; (If greater than zero pay this amount. If less than zero complete lines 15(a) and 15(b).) ........
15. If lines 14 is an overpayment (i.e. less than zero) indicate amount to be:
    (a) Refunded: ....................
    (b) Applied to your estimated tax for next year: ....................

I declare under the penalties of perjury that I have examined this Return including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. If prepared by a person other than the taxpayer, his declaration is based on all information of which he has any knowledge.

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Date Signature of Officer Title



3/79

Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Questionnaire and Other Required Information.

A. Attach a schedule of the following information for each corporation included in this Return (Note; Place an asterisk by corporations doing business in Alaska and deriving income from oil and gas production in Alaska or Alaska OCS or deriving income from one or more oil or gas pipelines in Alaska; see also (B) this page);

(1) Name.
(2) Federal Employer Identification Number.
(3) Address.
(4) Date began doing business in Alaska.
(5) State or country in which business was incorporated or formed.
(6) State or country of commercial domicile.
(7) Percentage of voting stock owned by the parent company or by any other entity within the consolidated business (indicate each such stockholder's name and address).
(8) Net income of each corporation reported to stockholders for the period covered by this Return.

B. Did any corporation included in this Return and doing business in Alaska during the tax year, conduct through one or more non-corporate intermediaries operations that generated income for those intermediaries which would make them subject to tax under AS 43.21--if they had been corporations? ______. If the answer is yes, attach a schedule showing the following information:

(1) Name of each corporation which conducted business in this manner.
(2) Name of each intermediary.
(3) Type of intermediary (e.g., individual, estate, trust, partnership).
(4) Address of each intermediary.
(5) Federal Employer Identification Number or Social Security Number of each intermediary.
(6) Percentage of voting stock of each corporation listed in B.(1), above, which is directly or indirectly owned by each intermediary listed in B.(2), above.

C. Name, title, mailing address and phone number of the individual who should be contacted concerning an audit of this Return: ______________________

______________________________________________

D. Location(s) of principal accounting records: ______________________

______________________________________________

E. Location(s), if different than (D) above, of minutes of this year's meetings of the Board of Directors, Executive Committee and/or any other committee involved in the business operations of the parent corporation or non-corporate intermediary exercising direct or indirect control over the consolidated business: ______________________

______________________________________________

F. Name and address on the prior year's Return if different from this year. State the reason for the change (e.g., merger, name change, moved to new location, etc.,): ______________________

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Instructions.

15 AAC 12.010. PERSONS SUBJECT TO THIS CHAPTER. A corporation doing business in the state and deriving income from one or more of the following sources is subject to the provisions of this chapter, even if that income is more than offset during a year by expenses associated with it:

(1) a production interest in one or more leases or properties in commercial production that are within the state;

(2) a production interest in one or more leases or properties in commercial production that are in areas within the United States and adjacent to the State of Alaska but not within this or any other state, and which are supported from a base of operations within this state;

(3) the transportation of oil or gas or both by means of a pipeline or pipeline system of which part or all is within the state.

15 AAC 12.020. TAXPAYERS HAVING INCOME FROM OTHER ACTIVITIES. A taxpayer deriving income from one or more sources in addition to any of those listed in sec. 10 of this chapter is subject to the requirements and income tax liability under AS 43.21 and this chapter only, for all of its income.

15 AAC 12.030. CONSOLIDATED BUSINESS. (a) A group of two or more corporations that are directly or indirectly controlled or at least 50-percent owned (directly or through one or more intermediaries) by one common person (corporate or otherwise) constitute a consolidated business for purposes of this chapter.

(b) The income, expenses and assets of a consolidated business include, respectively, all income, expenses and assets attributed to it under sec. 40 of this chapter.

(c) If a corporation or consolidated business is in turn itself controlled (by a means characteristic of ownership rather than through the exercise of general governmental powers such as laws, regulations, judicial decisions, proclamations and the like) or at least 50 percent owned by a sovereign, head of state, government or governmental agency, the consolidated business does not include the sovereign, head of state, government or governmental agency for purposes of this chapter.

15 AAC 12.040. ATTRIBUTION OF INCOME. (a) The income, expenses and assets of an enterprise involving undivided joint ownership must be attributed to the joint owners of that enterprise on the basis of their respective ownership interests, as may be modified by agreement among those joint owners. For purposes of this section, partnerships, joint ventures, trusts with joint beneficiaries and similar legal entities (but not a corporation) are enterprises involving undivided joint ownership.

(continued)

Instructions.

(b) If a corporation doing business in the state conducts, through one or more non-corporate intermediaries, operations that generate income for those intermediaries which would make them subject to tax under AS 43.21 and this chapter if they were corporations, then that corporation is presumed to derive income from those operations in the amount of the income earned by those intermediaries and therefore subject to tax under this chapter. Such a corporation's tax is calculated using the revenues and deductions of the intermediaries, as if the corporation were directly conducting the operations actually conducted by the intermediaries.

15 AAC 12.050. NET TAXABLE INCOME. (a) A taxpayer's 5.4-percent tax and 4-percent surtax under AS 43.21 and this chapter for a year are on the taxpayer's net taxable income for that year as determined under (b) of this section, except that the surtax will be computed on that net taxable income minus the surtax exemption specified in sec. 60 of this chapter.

(b) A taxpayer's net taxable income for a year is that taxpayer's taxable production income under sec. 100 of this chapter for that year, plus that taxpayer's taxable oil pipeline income under sec. 300 of this chapter for that year, plus that taxpayer's taxable gas pipeline income under sec. 400 of this chapter for that year, plus that taxpayer's taxable apportioned income under sec. 500 of this chapter for that year, and minus all net losses of that taxpayer that are being carried back or carried forward to that year from one or more other tax years in accordance with sec. 70 of this chapter. If the taxpayer's income under one or more of secs. 100, 300, 400 and 500 of this chapter reflects a loss, the total of the losses under those sections is offset against the total gain (if any) under the rest of those sections.

15 AAC 12.060. SURTAX EXEMPTION. A taxpayer's surtax exemption shall be calculated in accordance with AS 43.20.011(e) and AS 43.20.021(a). The surtax exemption for tax year 1978 is $10,000. The surtax exemption, if any, for tax years after 1978 will be an amount determined under AS 43.20.

15 AAC 12.610. NOTICE OF COMMENCEMENT OF TAXABLE ACTIVITY. A corporation not subject to tax under AS 43.21 and this chapter shall, within 30 days of the time it begins to derive income (even if that income is exceeded by the expenses involved) from any of the sources described in sec. 10 of this chapter, give written notice to the department of the fact that it has begun deriving income from those sources. This section applies only to those who, after the effective date of AS 43.21 and the original adoption date of this section, begin deriving income from any source described in sec. 10 of this chapter.

(continued)

Instructions.

15 AAC 12.700. RETURNS AND ASSESSMENTS. (a) A taxpayer reporting on a calendar year basis shall file, on or before April 15 of each year, a tax return on such forms as may be prescribed by the department, setting out all the information required in determining that taxpayer's net taxable income under this chapter for the previous year and the amount of tax due on that income.

(b) A fiscal-year taxpayer shall file, on or before the 15th day of the fourth month after the month in which the taxpayer's fiscal year ends, a tax return on such forms as may be prescribed by the department, setting out all the information required in determining that taxpayer's net taxable income under this chapter for the taxpayer's fiscal year last ended and the amount of tax due on that income.

(c) In its discretion, the department will grant a taxpayer an extension of as many as 60 days from the deadlines for filing returns specified in (a) and (b) of this section. An application for an extension must be on a form prescribed by the department, setting forth all the information required to support the application.

(d) Returns required under this section must be filed by the corporation deriving income (or to which income is attributed under sec. 40 of this chapter) from one or more of the sources described in sec. 10 of this chapter. Where two or more such corporations are parts of the same consolidated business, they shall file a single consolidated return.

(e) On or before August 15 (for fiscal-year taxpayers, the 15th day of the eighth month after the month in which the taxpayer's fiscal year ends), the department will assess the taxpayer and send the taxpayer a notice of assessment showing the amount of net taxable income under this chapter for that taxpayer during the previous year, the total amount of tax due under this chapter, and the amount (if any) of that tax remaining unpaid or overpaid. Returns and assessments under this section are subject to amendment for three years from the date of the original notice of assessment.

15 AAC 12.710. PAYMENTS; INSTALLMENTS. (a) For the 1978 tax year, each taxpayer shall prepay its estimated tax under this chapter in an installment on or before March 15, 1979, which, when combined with the taxpayer's installment payments (if any) of estimated tax under AS 43.20 and ch. 5 of this title made after December 31, 1977, brings the total prepaid tax to 100 percent of the tax and surtax on the taxpayer's total estimated 1978 net taxable income under this chapter, as that net taxable income is estimated and reported by the taxpayer at the time it makes the installment.

(b) For tax years after the 1978 tax year, each taxpayer shall prepay its estimated tax under this chapter in installments in accordance with the following schedule:

Instructions.

(1) On June 15 of each year (for a fiscal-year taxpayer, the 15th day of the sixth month after the start of the fiscal year), a first installment comes due that is equal to one-quarter of the tax and surtax on the taxpayer's total estimated net taxable income for that year under this chapter, as that net taxable income is then estimated and reported by the taxpayer.

(2) On September 15 of each year (for a fiscal-year taxpayer, the 15th day of the ninth month after the start of the fiscal year), a second installment comes due that, when combined with the first installment, brings the total prepaid tax to one-half of the tax and surtax on the taxpayer's total estimated net taxable income for that year under this chapter, as that net taxable income is then estimated and reported by the taxpayer

(3) On December 15 of each year (for a fiscal-year taxpayer, the 15th day of the 12th month after the start of the fiscal year), a third installment comes due that, when combined with the first two installments, brings the total prepaid tax to three-quarters of the tax and surtax on the taxpayer's total estimated net taxable income for that year under this chapter, as that net taxable income is then estimated and reported by the taxpayer.

(4) On March 15 of each year (for a fiscal-year taxpayer, the 15th day of the 15th month after the start of the fiscal year), a fourth installment comes due that, when combined with the first three installments, brings the total prepaid tax to 100 percent of the tax and surtax on the taxpayer's total estimated net taxable income under this chapter for the year in question,as that net taxable income is then estimated and reported by the taxpayer.

(c) If, because of [illegible] events, a taxpayer has to revise its total estimated net taxable income downward so significantly that its prior installments that year under (b) of this section equal or exceed the amount to which the total prepaid tax is to be brought when the next installment comes due, then the taxpayer needs only to report the current estimate of its total tax for that year and does not need to make any further payment as an installment at that time. No refund will be made at that time as the result of a taxpayer's having a negative installment an apparent overpayment from its prior installments; however, if the condition of overpayment continues until the time of the department's assessment under sec. 700 of this chapter, the remaining overpayment will then be handled as an ordinary refund under sec. 720 of this chapter.

(d) At the time a taxpayer files its tax return required under sec. 700 of this chapter, the taxpayer shall pay the excess, if any, of its total tax over the amount already paid by the taxpayer in its installments under this section.

(continued)



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Instructions.

(e) If the department's assessment under sec. 700 of this chapter shows a total tax for a taxpayer greater than the amount already paid by the taxpayer in its installments and its payment made at the time of filing its return under sec. 700 of this chapter for that year, the taxpayer shall pay the additional amount of tax on or before September 30 (for a fiscal-year taxpayer, the last day of the ninth month after the month in which the taxpayer's latest fiscal year ended).

(f) A payment of $50,000 or more must be made by wire transfer of funds, in accordance with the standard procedures required by the department for wire transfers. Payment of smaller sums may be by wire transfer, check, money order, or cash.

(g) Payments and reports required under this section shall be made on the same basis as returns required under sec. 700 of this chapter.

15 AAC 12.720. REFUNDS. (a) The department will refund to a taxpayer any overpayment of the taxpayer's tax for a year under this chapter on or before September 30 of the following year (in the case of a fiscal-year taxpayer, the last day of the ninth month after the month in which the taxpayer's fiscal year ended). The amount of the overpayment will be determined on the basis of the tax as determined by the department in its assessment under sec. 700 of this chapter for the year in question, unless the overpayment arises from a reduction in the assessment as the result of a subsequent audit by the department or a carry-back of a later year's net loss under sec. 70 of this chapter. In the case of such a reduction in a taxpayer's assessment, the refund by the department will equal that reduction. In addition, the department will simultaneously pay the taxpayer any interest due on the refund as computed in accordance with sec. 730 of this chapter.

(b) At its option, the taxpayer may elect to have the department apply the amount of a refund (including any interest) under this section as a credit against future payments of tax coming due under this chapter, instead of remitting the refund to the taxpayer.

15 AAC 12.740. CIVIL PENALTIES. For unpaid taxes to which paragraph (1),(2), or (3) of sec. 730(a) of this chapter applies, the civil penalty provided by AS 43.05.220 will be imposed beginning the day after the starting date specified in the applicable paragraph of that section. For unpaid taxes to which paragraph (4) of sec. 730(a) of this chapter applies, the civil penalty provided by AS 43.05.220 will be imposed beginning the 31st day after the department's written notice to the taxpayer of an increase in its assessment as the result of an audit by the department.

(continued)

Instructions.

15 AAC 12.820. FISCAL-YEAR TAXPAYERS. All taxpayers shall report and pay tax under this chapter on a calendar year basis unless they have received prior written authorization from the department to report and pay tax under this chapter on a fiscal year basis. The department, in its discretion, will grant such an authorization to a taxpayer, but only if the taxpayer's financial accounting is done on a fiscal year (as opposed to calendar year) basis. If granted, each such authorization by the department authorizes a taxpayer to report and pay tax under this chapter on the basis of only the fiscal year that is used for purposes of the taxpayer's financial accounting and not on the basis of any other fiscal year. A taxpayer thus authorized to use its financial accounting fiscal year is a "fiscal-year taxpayer".

Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Taxable Production Income (Loss) Schedule B

1. Gross Production Revenue. (From Schedule B.1)........................ ______

2. Extraordinary Production Revenue or (Loss). (Total of the amounts entered on line 13 of the Schedules B.8 that are filed as part of this Return).......... ................................................ ______

3. Add amounts on lines 1 and 2........................................... ______

Deductions from Gross Production Revenue

4. Royalties. (Total of the amounts entered on line 3 of the Schedules B.9 that are filed as part of this Return).................. ______

5. Production Taxes. (Total of the amounts entered on line 3 of the Schedules B.10 that are filed as part of this Return).................. ______

6. Ad Valorem Taxes. (Total of the amounts entered on line 3 of the Schedules B.11 that are filed as part of this Return).................. ______

7. Direct Operating Costs. (Total of the amounts entered on line 10 of the Schedules B.12 that are filed as part of this Return)............. ______

8. Acquisition Costs. (Total of the amounts entered on lines 6, 21 and 43 of the Schedules B.13 that are filed as part of this Return).... ______

9. Development Costs. (Total of the amounts entered on lines 4, 21 and 47 of the Schedules B.14 that are filed as part of this Return).... ______

10. Exploration Costs. (The amount entered on line 10 of Schedule B.15)... ______

11. Uncapitalized Interest. (The amount entered on line 9 of Schedule B.16) ______

12. General Overhead and Administrative Expense. (The amount entered on line 23 of Schedule B.17)................................................ ______

13. Total Deductions. (Add amounts on lines 4-12).......................... ______

14. Taxable Production Income. (Line 3 less line 13; enter also on Schedule A, line 1)................................................... ______

Instructions: Taxable Production Income

15 AAC 12.100. TAXABLE PRODUCTION INCOME. A taxpayer's taxable production income during a year equals the total of the taxpayer's gross production revenue (determined in accordance with secs. 110 -- 130 of this chapter) during that year for each lease or property in the state in which the taxpayer has a production interest, plus the total of the taxpayer's extraordinary production revenue (determined in accordance with sec. 140 of the chapter), if any, during that year for each lease or property in the state in which the taxpayer has a production interest, minus the total of the taxpayer's deductions for that year under secs. 200 -- 290 of this chapter, and minus the total of the taxpayer's extraordinary production loss (determined in accordance with sec. 140 of this chapter), if any, during that year for each lease or property in the state in which the taxpayer has a production interest.

15 AAC 12.110. GROSS PRODUCTION REVENUE. A taxpayer's gross production revenue during a year from a production interest in a lease or property is the value at the point of production of the taxpayer's gross share of the oil and gas produced from (or allocated to) that lease or property; however, oil or gas that is used, flared or unavoidably lost in the production operations for the lease or property or is injected into a reservoir in the course of the operations for the same field, may not be included in determining the taxpayer's gross production revenue from that or any other lease or property.

15 AAC 12.120. VALUE AT THE POINT OF PRODUCTION. (a) The value at the point of production for oil or gas produced from a lease or property is the sales price of that oil or gas, minus the reasonable cost of transportation (if any) from the point of production for that oil or gas to the sales delivery point for that oil or gas; except that in no event may the value at the point of production for a taxpayer's oil or gas exceed the ceiling price (if any) that is applicable to that oil or gas under a mandatory price control program.

(b) For purposes of this chapter, "sales price" means

(1) for a taxpayer's oil and gas sold in a bona fide, arm's length sale to a third party, the cash value of the full consideration given and received for that oil and gas, except in the case of a sale to which (f) of this section applies;

(2) for a taxpayer's oil not sold in a bona fide, arm's length sale to a third party, the total acquisition cost for imported oil of similar quality delivered F.O.B. at the gate of the refinery to which the taxpayer's oil is ultimately delivered, with an appropriate adjustment for differences, if any, in quality or in entitlements treatment between the two oils (whenever possible, such an adjustment will be based on market data involving bona fide, arm's length sales of comparable Alaskan oil and similar imported oil); and

(continued)



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Instructions: Taxable Production Income

(3) for a taxpayer's gas not sold in a bona fide, arm's length sale to a third party, the volume-weighted average of the prices then being given and received under the terms of the sales contracts for significant quantities of gas (in terms of delivery rates or reserves committed, or both) which have been entered into or whose pricing provisions have been amended during the tax year or the two preceding years among all the bona fide, arm's length sales contracts (whether between third parties or not) applying to gas from the same field as the taxpayer's gas (or if there are no such contracts for that field, the counterparts of those contracts in the nearest field to that field), with an appropriate adjustment according to the ideal gas laws for any difference in the specified delivery pressure or temperature between the gas sold under the reference sales contracts and the taxpayer's gas.

(c) For purposes of this chapter, "sales delivery point" means

(1) for a taxpayer's oil and gas sold in a bona fide, arm's length sale to a third party, the point of delivery under the terms of the contract or agreement for that sale, except in the case of a sale to which (f) of this section applies;

(2) for a taxpayer's oil not sold in a bona fide, arm's length sale to a third party, the gate of the refinery to which that oil is ultimately transported; and

(3) for a taxpayer's gas not sold in a bona fide, arm's length sale to a third party, the point of delivery under the terms of the sales contract being used as the reference for the sales price of the taxpayer's gas under (b)(3) of this section.

(d) For purposes of this chapter, "point of production" means

(1) for oil, the automatic custody transfer meter or unit through which the oil enters into the facilities of a carrier pipeline or other transportation carrier; and in the absence of an automatic custody transfer meter or unit, the "point of production" for oil is the outlet flange of the tank gauge (or in the absence of a tank gauge, another mechanism or device to measure the quantity of oil that has been approved by the department for this purpose) through which the oil is tendered and accepted into the facilities of a carrier pipeline or other transportation carrier;

(2) for gas, the meter on, or nearest (measured along the course taken by the gas) to, the lease or property from which the gas is recovered, at which meter the sales stream of gas is measured with sufficient accuracy and at appropriate temperature, pressure and other condition for purposes of sale, regardless whether the particular gas in question is actually sold at that meter.

(continued)



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Instructions: Taxable Production Income

(e) Notwithstanding anything to the contrary in (a) - (d) of this section, where a taxpayer's gas from a lease or property is run through a gas processing plant and part or all of the residue gas and extracted liquids are returned to that taxpayer, the "value at the point of production" for that gas is the total value of that residue gas and extracted liquids as they come out of the plant, less (1) a reasonable allowance (either withheld in kind by the plant operator or paid in cash to the plant operator) for the cost of processing that gas through the plant, (2) the reasonable cost of transportation, if any, from the point of production for that gas to the intake into the plant, and (3) the value of any residue gas returned to the taxpayer that is used, flared or unavoidably lost in the production operations for the lease or property or is injected into a reservoir in the course of operations for the same field.

(f) If a taxpayer sells its oil or gas to a third party in what would otherwise be a bona fide, arm's length sale but at the time of this particular sale the taxpayer expects to repurchase that oil or gas at a subsequent time and place, then that sale to the third party and the repurchase from the third party, when it occurs, must be disregarded and the oil or gas subject to that sale must be regarded as if it had remained the taxpayer's own oil or gas throughout the time between that sale and repurchase. In determining the value at the point of production in such a case, the reasonable cost of transportation between the point of sale for that sale and the point of repurchase must be determined as if the taxpayer were the shipper for purposes of sec. 130 of this chapter. This subsection does not apply if the taxpayer's expected repurchase does not in fact occur.

15 AAC 12.130. REASONABLE COSTS OF TRANSPORTATION. (a) In the case of transportation of oil or gas by a regulated carrier, the reasonable cost for that transportation is, for purposes of this chapter, the tariff on file with FERC or other regulatory agency having jurisdiction that is applicable to that transportation of the oil or gas by the carrier, from the point where that oil or gas is tendered into the facilities of the carrier to the point where it is delivered from the facilities of the carrier.

(b) In the case of transportation of oil by a tanker or other vessel that is not owned or effectively owned by the shipper of that oil,

(1) for a single voyage charter, the reasonable cost for that transportation is, for purposes of this chapter, the charter fee for that vessel, plus any voyage and port costs not included in that fee which are incurred with respect to that transportation during the term of the charter and which are borne by the shipper, plus the positioning cost, if any, borne by the shipper for that vessel;

(continued)

Instructions: Taxable Production Income

(2) for a consecutive voyage charter or a time charter, the reasonable cost for that transportation is, for purposes of this chapter, the charter fee for that vessel, plus any voyage and port costs not included in that fee which are incurred with respect to that transportation during the term of the charter and which are borne by the shipper, plus the positioning cost (amortized over the lesser of 36 months or the term of the charter in the case of a time charter, and amortized on the basis of the number of voyages in the case of a consecutive voyage charter), if any, borne by the shipper for that vessel;

(3) for a contract of affreightment, the reasonable cost for that transportation is, for purposes of this chapter, the affreightment fee specified in that contract, plus any voyage and port costs and any positioning costs not included in that fee which are incurred with respect to that transportation during the term of the contract of affreightment and which are borne by the shipper.

(c) In the case of transportation of oil by a tanker or other vessel that is owned or effectively owned by the shipper of that oil, the department may, at the request of a taxpayer (but in the department's sole discretion), authorize the taxpayer to use the fair market value of like transportation as the reasonable cost for the transportation in question. If the taxpayer's request is granted, the department, and not the taxpayer, will determine the fair market value of like transportation, on the basis of third-party time charters (that is, time charters in which the shipper does not own or effectively own the vessel) of one year or more which are reported to the department for like vessels; and when it makes its determination, the department will notify the taxpayer of it in the notice of assessment described in sec. 700 of this chapter. Two vessels will be considered like vessels for purposes of this chapter if the difference between them in deadweight tonnage is less than 10,000 deadweight tons and if they are both Jones Act vessels, or are both CDS vessels, or are both ODS vessels or are both CDS/ODS vessels. If the department does not authorize the taxpayer to use fair market value of like transportation (as described in this subsection) as the reasonable cost for the transportation in question, then the reasonable cost for that transportation is, for purposes of this chapter, the taxpayer's actual cost for that transportation. This actual cost equals the sum of

(1) the voyage and port costs incurred with respect to that transportation,

(2) the positioning cost, amortized over 36 months, for that vessel, but only for placing that vessel into position before its employment in the Alaska trade and not for placing it into position after its employment in the Alaska trade for employment in another trade,

(continued)

Instructions: Taxable Production Income

(3) depreciation of the vessel; if the vessel is actually owned by the shipper, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for such owned assets; if the vessel is effectively owned by the shipper, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(4) an amount which, when taken together with depreciation under (3) of this subsection, will provide a reasonable rate of return on the acquisition cost of the vessel over its expected life; for purposes of this paragraph,

(A) "acquisition cost" means the cost of the vessel which may be capitalized by its actual owner under generally accepted financial accounting principles, and

(B) "expected life" means the period of time used to calculate depreciation under (3) of the subsection.

(d) In the case of transportation of gas as LNG where not all of the LNG transportation facilities are subject to tariff regulation (by FERC or another agency of the United States, a state, a territory or possession of the United States or a foreign nation),

(1) when the shipper does not have or effectively have an ownership interest in the LNG transportation facility, the reasonable cost of transportation for that LNG transportation facility is, for purposes of this chapter, the amount charged to the shipper for that LNG transportation; or

(2) when the shipper has or effectively has an ownership interest in the LNG transportation facility, the department may, at the request of a taxpayer (but in the department's sole discretion), authorize the taxpayer to use the fair market value of like transportation as the reasonable cost for the transportation in question. If the taxpayer's request is granted, the department, and not the taxpayer, will determine the fair market value of like transportation, on the basis of third-party charters or leases (that is, charters or leases in which the shipper does not own or effectively own the LNG transportation facility in question) of three years or more which are reported to the department for like LNG transportation facilities; and if it makes such a determination, the department will notify the taxpayer of it in the notice of assessment described in sec. 700 of this chapter. If the department does not authorize the taxpayer to use fair market value of like transportation (as described in this paragraph) as the reasonable cost for the transportation in question, then the reasonable cost for that transportation is, for purposes of this chapter, the taxpayer's actual cost for that transportation. This actual cost equals the sum of

(A) the direct operating costs of the LNG transportation facility (in the case of an LNG tanker, its respective voyage and port costs) incurred with respect to the shipper's gas;

(continued)

(B) depreciation of the LNG transportation facility; if the facility is actually owned by the shipper, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for the owner of such assets; if the LNG transportation facility is effectively owned by the shipper, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(C) an amount which, when taken together with depreciation under (B) of this paragraph, will provide a reasonable rate of return on the acquisition cost of the LNG transportation facility over its expected life; for purposes of this subparagraph,

(i) "acquisition cost" means the cost of the LNG transportation facility which may be capitalized by its actual owner under generally accepted financial accounting principles, and

(ii) "expected life" means the period of time used to calculate depreciation under (B) of this paragraph.

(e) For purposes of this chapter, "voyage and port costs" for a vessel are

(1) costs actually incurred for fuel for the vessel while in port and at sea, stores and provisions for the vessel and for her captain and crew, wages and benefits of the vessel's captain and crew, routine maintenance, port and dock fees, storage costs, demurrage, tug and pilotage fees, marine agents' fees in port, lightering, transshipment charges, customs fees and duties, regular and customary gratuities that are also legal, insurance premiums actually paid, minor cargo losses or measuring differentials, loading and unloading inspection fees, Panama Canal transit fees, a reasonable management fee (to be pro-rated equally among vessels) for coordinating arrivals and departures into and out of ports for vessels owned, effectively owned or chartered by the shipper, and other reasonable costs associated with the operation or maintenance (or both) of the vessel; and

(2) in addition to the costs listed in (1) of this subsection, in the case of catastrophic loss or damage of a vessel transporting oil or LNG from Alaska or enroute to Alaska to take on oil or LNG, a portion of the loss (for loss or damage of the ship, for injury or loss of her captain or crew and for damage and clean-up due to spillage of part or all of her cargo, but not for the loss of the cargo itself) which is borne by the shipper as the result of that catastrophic loss or damage and which is not reimbursed by insurance or by a third party; this portion of the loss is determined by dividing the unreimbursed liability on the basis of deadweight tonnage among the vessels owned, effectively owned or chartered by the shipper to transport oil or LNG (whichever was lost) from Alaska.

(continued)

Instructions: Taxable Production Income

(f) A person "effectively owns", has "effective ownership" or "effectively has an ownership interest" in a vessel or LNG transportation facility for purposes of this section if either

(1) the vessel or LNG transportation facility is owned by another person comprising part of a consolidated business in which the first person is also a part; or

(2) the vessel or LNG transportation facility is the subject of a capital lease in which the person, or another person comprising part of a consolidated business in which the first person is also a part, is the lessee.

(g) For purposes of this chapter, the "positioning cost" for a vessel includes the costs not included in the charter for that vessel which are borne by the shipper for placing that vessel into position before the first voyage under that charter or the estimated costs to be borne by the shipper for delivering it up at a specified location after the last voyage under that charter, or both if the shipper is obligated under the terms of the charter or contract of affreightment to bear them both.

(h) A reasonable rate of return under (c) (4) or (d)(2)(C) of this section is presumed to be that internal rate of return (after federal income tax) on an investment which equals two percent plus the average annual national inflation rate (measured by the GNP deflator) during (1) the period between the time the commitment is made to construct or acquire the vessel or LNG transportation facility and the time when the vessel or LNG transportation facility has been received (or delivered) and is ready to be placed into service, or (2) if the period in (1) of this subsection falls entirely within a calendar year, that entire calendar year. At the request of a taxpayer or on its own motion, the department may replace this presumed rate of return with one based on the rate of return imputed to that investment or similar ones by the person owning or effectively owning the vessel or LNG transportation facility.

(i) The third party nature of an agreement between a shipper and a third-party carrier regarding transportation costs is not affected during the term of that agreement by a subsequent consolidation of that shipper and carrier into a consolidated business, if, at the time they entered that agreement neither the shipper nor the carrier exercised, directly or indirectly, any control over the business affairs of the other as the result of, or in anticipation of, their subsequent consolidation into the same consolidated business.

Gross Production Revenue — Schedule B.1

## Gross Production Revenue: Oil

1. Sales Proceeds. (Total of the amounts entered on line 7 of the Schedules B.2 that are filed as part of this Return)............... ______

2. Costs of Transportation. (Total of the amounts entered on line 4 of the Schedules B.3 that are filed as part of this Return)............ ______

3. Subtract the amount on line 2 from the amount on line 1................ ______

## Gross Production Revenue: Gas

4. Sales Proceeds. (Total of the amounts entered on line 13 of the Schedules B.5 that are filed as part of this Return)............... ______

5. Costs of Transportation. (Total of the amounts entered on line 8 of the Schedules B.6 that are filed as part of this Return)............ ______

6. Subtract the amount on line 5 from the amount on line 4................ ______

7. Gross Production Revenue. Add the amounts on lines 3 and 6............ ______

Sales Proceeds: Oil

Schedule B.2

NOTE: A separate copy of this schedule must be completed for each property in Alaska with commercial oil production; in cases of unitization, the unit (or if the unit is divided into participating areas, the participating area) is the "property" for purposes of this schedule.

1. Identify the property. ______________________

Category I: Oil Production Being Reported at its Full Ceiling Price

2. Volume of oil in Category I.......................... ________ bbls.

3. Value of oil in Category I........................... ________

Category II: Other Oil Production

4. Volume of oil in Category II......................... ________ bbls.

5. Gross proceeds from oil in Category II that was sold to one or more third parties:

   (a) in contemplation of subsequently reacquiring it, but it was in fact not subsequently reacquired (use the sales price)........................... ________

   (b) in contemplation of subsequently reacquiring it, and after it was in fact reacquired it was again sold to one or more third parties (use the price of the second sale)............................. ________

   (c) not in contemplation of subsequently reacquiring it (use the sales price)................................ ________

   (d) total: add lines 5(a), 5(b) and 5(c)........................ ________

(continued)

Sales Proceeds: Oil | Schedule B.2

6. Value of oil in Category II

(a) that was not sold to a third party (use the acquisition cost for similar imported oil delivered F.O.B. at the same destination).......... ______

(b) that was sold to one or more third parties in contemplation of subsequently reacquiring it and after it was in fact reacquired it was not sold to a third party (use the acquisition cost for similar imported oil delivered F.O.B. at the same destination)............................ ______

(c) total: add lines 6(a) and 6(b)................................ ______

7. Total sales proceeds: add lines 2 5(d) and 6(c)................. ______



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Costs of Transportation: Oil — Schedule B.3

Oil transported by regulated carrier.

1. Attach a schedule identifying each regulated carrier (pipeline) and indicating:

   (a) The point(s) in Alaska where oil is tendered into the facilities of the carrier(s).

   (b) The point(s) where oil is delivered from the facilities of the carrier(s).

   (c) The transportation tariff rate(s) on file with FERC or other regulatory agency having jurisdiction over each carrier.

   (d) Total tariff paid each carrier for transporting oil during the tax year between points 1(a) and (b), above.

2. Total Tariff Paid All Carriers During the Tax Year .................... ________

3. Total Tanker and Other Vessel Costs. (Total of the amounts entered on line 18 of the Schedules B.4 that are filed as part of this Return) ........................................ ________

4. Total Costs of Transportation: Oil. Add amounts on lines 2 and 3 .... ________



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Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Submit a completed Schedule B.4 for each tanker or other vessel.

Costs of Transportation: Oil — Schedule B.4
Tankers or Other Vessels Not Owned:
Single Voyage Charter. 15 AAC 12.130(b)(1).

1. Charter Fees .............................................. ________
2. Voyage and Port Costs (not in charter fees) ............ ________
3. Positioning Costs .......................................... ________
4. Total. Add amounts on lines 1, 2 and 3 .................................... ________

Consecutive Voyage or Time Charter. 15 AAC 12.130(b)(2).

5. Charter Fees .............................................. ________
6. Voyage and Port Costs (not in charter fees) ............ ________
7. Amortized Positioning Costs ............................ ________
8. Total. Add amounts on lines 5, 6 and 7 .................................... ________

Contract(s) of Affreightment. 15 AAC 12.130(b)(3).

9. Affreightment Fees ...................................... ________
10. Voyage and Port Costs (not in affreightment fees) ...... ________
11. Total. Add amounts on lines 9 and 10 ...................................... ________

Tankers or Other Vessels Owned or Effectively Owned. 15 AAC 12.130(c).
Fair Market Value Method: (Attach a copy of the Department of Revenue letter of approval to use this method.)

12. FMV of Transportation Costs ............................ ________

Actual Cost Method:

13. Voyage and Port Costs. 15 AAC 12.130(c)(1).
(Attach schedule) ............................................ ________
14. Positioning Costs. 15 AAC 12.130(c)(2).
(Attach schedule) ............................................ ________
15. Depreciation. 15 AAC 12.130(c)(3).
(Attach schedule) ............................................ ________
16. Return on Acquisition Costs. 15 AAC 12.130(c)(4).
(Attach schedule) ............................................ ________
17. Total. Add amounts on lines 13,14,15 and 16 ............................ ________
18. Total Tanker and Other Costs. Add amounts on lines 4, 8, 11, 12 and 17 .......................................... ________

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Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Sales Proceeds: Gas

Schedule B.5

NOTE: A separate Schedule B.5 must be completed for each property in Alaska with commercial gas production; in cases of unitization, the unit (or if the unit is divided into participating areas, the participating area) is the "property" for purposes of this schedule.

1. Identify the property. ______________________
2. Date of sales contract(s) and most recent amendment(s). ______________________

Lines 3 through 7 are only for gas not run through a gas processing plant. Complete lines 8 through 12 for gas run through a gas processing plant.

Category I: Gas Production Being Reported at its Full Ceiling Price.

3. Volume of gas in Category I.............................. ________ Mcf
4. Value of gas in Category I.............................. ________

Category II: Other Gas Production.

5. Volume of gas in Category II.............................. ________ Mcf
6. Gross proceeds from gas that was sold to one or more third parties:
   (a) in contemplation of subsequently reacquiring it, but it was in fact not subsequently reacquired (use the sales price).............................. ________
   (b) in contemplation of subsequently reacquiring it, and after it was in fact reacquired it was again sold to one or more third parties (use the price of the second sale).............................. ________
   (c) not in contemplation of subsequently reacquiring it (use the sales price).............................. ________
   (d) Total. Add the amounts on lines 6(a), 6(b) and 6(c).............................. ________

7. Value of gas in Category II:

   (a) that was not sold to a third party (use your most recent or highest price as an interim value).............................. ________
   (b) that was sold to one or more third parties in contemplation of subsequently reacquiring it and after it was in fact reacquired it was not sold to a third party (use your most recent or highest price as an interim value).............................. ________
   (c) Total. Add amounts on lines 7(a) and 7(b).............................. ________

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(continued)

Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Sales Proceeds: Gas

Schedule B.5

Where gas is run through a gas processing plant and part or all of the residue gas and extracted liquids are returned to the taxpayer, the following costs must be reported. 15 AAC 12.120(e):

8. Volume of extracted liquids that are:
   (a) attributed to the gas run into the plant .......... ________ Bbl
   (b) withheld by the plant operator for plant processing costs .......... ________ Bbl
   (c) used, flared or unavoidably lost in production operations for the same field .......... ________ Bbl
   (d) injected into a reservoir in the course of operations for the same field .......... ________ Bbl
   (e) net to the taxpayer. Line 8(a) minus the sum of lines 8(b), (c) and (d) .......... ________ Bbl

9. (a) Price per barrel of taxpayer's net extracted liquids .......... ________ Bbl
   (b) Proceeds from extracted liquids. Line 8(e) times 9(a) .......... ________

10. Value of residue gas that is:
   (a) attributed to the gas run into the plant .......... ________ Mcf
   (b) withheld by the plant operator as plant processing costs .......... ________ Mcf
   (c) used, flared or unavoidably lost in production operations for the same field .......... ________ Mcf
   (d) injected into a reservoir in the course of operations for the same field .......... ________ Mcf
   (e) net to the taxpayer. Line 10(a) minus the sum of lines 10(b), (c) and (d) .......... ________ Mcf

11. (a) Price per Mcf of taxpayer's residue gas .......... ________ $/Mcf
   (b) Proceeds from residue gas. Line 10(e) times 11(a). ________

12. Total. Lines 9(b) plus 11(b) ..........

13. Sales Proceeds: Gas. Total of lines 4, 6(d), 7(c), and 12 ..........

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Submit a completed Schedule B.6 for each LNG Transportation Facility.

Costs of Transportation: Gas | Schedule B.6

Gas transported as LNG and not all of the LNG transportation facilities are subject to tariff regulation (by FERC or another agency of the U.S., a state, territory or possession of the U.S. or a foreign nation).

LNG Transportation Facility Not Owned. 15 AAC 12.130(d)(1).

1. Amount Paid to Carrier(s) .................................................. ________

LNG Transportation Facility Owned or Effectively Owned. 15 AAC 12.130(d)(2).

Fair Market Value Method. (Attach a copy of the Department of Revenue letter of approval to use this method)

2. FMV of Transportation Costs .............................................. ________

Actual Cost Method.

3. Direct Operating Costs. 15 AAC 12.130(d)(2)(A).
   (Attach schedule) .............................................. ________
4. Depreciation. 15 AAC 12.130(d)(2)(B).
   (Attach schedule) .............................................. ________
5. Return on Acquisition Costs. 15 AAC 12.130(d)(2)(C).
   (Attach schedule) .............................................. ________
6. Total. Add the amounts on lines 3, 4 and 5 .............................. ________
7. Total Tariff Paid All Carriers. (Schedule B.7, line 2) ............... ________
8. Total Costs of Transportation: Gas. Add the amounts on lines
   1, 2, 6 and 7 .............................................................. ________

Costs of Transportation: Gas | Schedule B.7

1. Attach a schedule identifying each regulated carrier (pipeline) and indicating:
   (a) The point(s) in Alaska where gas is tendered into the facilities of the carrier(s).
   (b) The point(s) where gas is delivered from the facilities of the carrier(s).
   (c) Total tariff paid each carrier for transporting gas during the tax year between points 1(a) and (b), above.
2. Total Tariff Paid All Carriers During the Tax Year ........................ ________

Extraordinary Production Revenue or (Loss) Schedule B.8

15 AAC 12.140. EXTRAORDINARY PRODUCTION REVENUE OR (LOSS). (a) A taxpayer's extraordinary production revenue or loss for a lease or property is fully recognized for purposes of this chapter in the year in which it is realized. There is no carry-back or carry-forward of extraordinary production revenue or loss under this chapter to any other year. except to the extent that an extraordinary production loss may contribute to a taxpayer's net loss under sec. 70 of this chapter. Multiple realizations of extraordinary production revenue or loss by a taxpayer during a single year are cumulative, with revenues added to revenues and losses to losses, and with revenues and losses offset against each other.

Enter on line 1 the amount of any extraordinary operating revenues or losses resulting from a retroactive increase or decrease in a tariff or fee allowed to be charged by a regulated carrier for transporting this taxpayer's oil or gas produced from a lease or property in Alaska. Also, indicate the effective date(s) of any such retroactive changes and the period covered, by carrier below:

| | Tariff or fee change: | | Period Covered: | | Volume subject |
|---|---|---|---|---|---|
| Effective Date: | From | To | From | To | to each change |
| | | | | | |
| | | | | | |
| | | | | | |

Line 2. The amount of the extraordinary production revenue or loss is the amount of the change at the point of production offset by any corresponding changes in deductions.
Enter on line 2 any such changes in deductions. 15 AAC 12.140(d).

Enter on line 4 the amount of any extraordinary operating revenues or losses resulting from retroactive changes in the sales price in a bona fide arm's length sale of this taxpayer's oil or gas produced from a lease or property in Alaska. Also, indicate the effective date(s) of any such retroactive changes and the period covered, by carrier below:

| | Sales price change: | | Period Covered: | | Volume subject |
|---|---|---|---|---|---|
| Effective Date: | From | To | From | To | to each change |
| | | | | | |
| | | | | | |
| | | | | | |

Line 5. The amount of the extraordinary production revenue or loss is the amount of the change at the point of production offset by any corresponding changes in deductions. Enter on line 5 any such changes in deductions. 15 AAC 12.140(d).

(continued)

Extraordinary Production Revenue or (Loss) Schedule B.8

## Catastrophic Losses

In the case of catastrophic loss of a taxpayer's oil or gas that has passed its point of production but for which the risk of loss has not shifted from the taxpayer to a common carrier or a third party, the taxpayer realizes an extraordinary production loss for that oil or gas. The amount of the taxpayer's extraordinary loss in such a case shall be the reasonable cost of transportation borne by the taxpayer for that oil or gas from its point of production to the point of its loss, plus the value at the point of production for that oil or gas but only to the extent that the value at the point of production for that oil or gas is included in the taxpayer's gross production revenue for the lease or property from (or to) which that oil or gas was produced (or allocated), and minus reimbursements to the taxpayer from insurance or from one or more third parties for that loss. 15 AAC 12.140(e).

Enter on line 9 the cost of transportation borne by the taxpayer for oil or gas lost in a c[illegible]ophe from its point of production to the point of the oil or gas catast[illegible] loss.

Enter on line 10 the value at the point of production for oil or gas lost in a catastrophe. Enter only the values for oil or gas that have been included in the taxpayer's gross production revenue.

Enter on line 11 reimbursements to the taxpayer from insurance or from one or more third parties for such catastrophic loss.

1. Retroactive Tariff Change: (a) Increased Cost ........... ________
   (b) Decreased Cost ........... ________

2. Resulting Change in Royalties Paid: (a) Increase ....... ________
   (b) Decrease ....... ________

3. Resulting Change in Production Tax Paid: (a) Increase.... ________
   (b) Decrease.... ________

4. (a) Extraordinary Revenue from Tariff Change: Line 1(b) less sum of lines 2(a) and 3(a) ............ ________

   (b) Extraordinary Loss from Tariff Change: Line 1(a) less sum of lines 2(b) and 3(b) ............ ________

   (c) Net Extraordinary Revenue or Loss from Tariff Change: Line 4(a) less line 4(b) ............ ________

5. Retroactive Price Change: (a) Increase .................. ________
   (b) Decrease .................. ________

6. Resulting Change in Royalties Paid: (a) Increase ....... ________
   (b) Decrease ....... ________

7. Resulting Change in Production Tax Paid: (a) Increase.... ________
   (b) Decrease.... ________

(continued)

Extraordinary Production Revenue or (Loss) — Schedule B.8

8. Extraordinary Revenue from Price Change: Line 5(a) less sum of lines 6(a) and 7(a) ........................................

(b) Extraordinary Loss from Price Change: Line 5(b) less sum of lines 6(b) and 7(b) ........................................

(c) Net Extraordinary Revenue or Loss from Price Change: Line 8(a) less line 8(b) ........................................

9. Cost of Transportation - Oil or Gas Catastrophic Loss ....( )

10. Value at Point of Producton - Oil or Gas Catastrophic Loss( )

11. Reimbursements - Oil or Gas Catastrophic Loss ............

12. Add the amounts on lines 9, 10 and 11............................

13. Extraordinary Production Revenue (Loss). Add lines 4(c), 8(c) and 12 ........................................

(Enter also on Schedule B, line 2.)



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## Deduction for Royalties

Schedule B.9

Submit a completed Schedule B.9 and B.10 for each Lease or Property.

15 AAC 12.210. DEDUCTION FOR ROYALTY. (a) The amount of royalty for a lease or property in the state that is paid during a year by or for a taxpayer is a deduction for purposes of determining the taxpayer's taxable production inc for that year.

(b) The value at the point of production (determined on the basis of the value at the point of production for the taxpayer's production interest at the time when the royalty is delivered) of royalty for a lease or property in the state that is delivered in kind by or for a taxpayer during a year is a deduction for purposes of determining the taxpayer's taxable production income for that year.

| | col. (a) Oil | col. (b) Gas |
|---|---|---|
| 1. Royalties Paid | | |
| 2. Value of Royalties Delivered in Kind | | |
| 3. Total. Add amounts on lines 1(a), 1(b), 2(a) and 2(b) | | |

## Deduction for Production Taxes

Schedule B.10

15 AAC 12.220. DEDUCTION FOR PRODUCTION TAXES. Taxes imposed under AS 43.55 and AS 43.57 for production from (or allocated to) a lease or property which are paid by, or on behalf of, a taxpayer during a year constitute a deduction in determining the taxpayer's taxable production income for that year. The amount of tax paid under AS 43.55 includes EDIC applied under AS 43.55.018 against that tax.

| | col. (a) Oil | col. (b) Gas |
|---|---|---|
| 1. Production Taxes Paid under AS 43.55 (Include EDIC applied) | | |
| 2. Production Taxes Paid under AS 43.57 | | |
| 3. Total. Add amounts on lines 1(a), 1(b), 2(a) and 2(b) | | |

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Deduction for Ad Valorem Taxes Schedule B.11

15 AAC 12.230. DEDUCTION FOR AD VALOREM TAXES. The amount of tax under AS 43.56 paid during a year to the state (net of credits or refunds made that year for municipal ad valorem taxes on the same properties) and the total amount paid that year for municipal ad valorem taxes under AS 29.53.045 -- .055, for a taxpayer's properties used directly in the production, gathering, treatment or preparation for pipeline shipment of oil and gas from a lease or property that is in commercial production before those payments to the state or any municipality are made, constitute a deduction in determining the taxpayer's taxable production income for that year.

Submit a completed Schedule B.11 for each lease or property.

1. Ad Valorem Taxes Paid to the State of Alaska ........................ ______

2. Ad Valorem Taxes Not Included on Line 1, above,

   Which Were Paid to the Alaska Municipality of:

   (a) ______________________________ ..................... ______

   (b) ______________________________ ..................... ______

   (c) ______________________________ ..................... ______

   (d) ______________________________ ..................... ______

   (e) ______________________________ ..................... ______

3. Total. Add the amounts on lines 1 and 2(a) - (e) ..................... ______

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Deduction for Direct Operating Costs — Schedule B.12

15 AAC 12.240. DEDUCTION FOR DIRECT OPERATING COSTS. (a) The direct operating costs during a year that are incurred by or for a taxpayer for a lease or property in the state are a deduction in determining the taxpayer's taxable production income for that year.

(b) Before the commencement of commercial production from (or allocated to) a lease or property, the direct operating costs for that lease or property are (1) the costs for geological and geophysical work conducted on the lease or property after the taxpayer has acquired a working interest in the lease or property, (2) rentals and shut-in royalties paid in order to retain the lease or property, and (3) the costs for operations conducted on or near the lease or property in support of drilling and/or development operations for the lease or property but excluding the actual drilling costs and development costs themselves; however, if the lease or property is subject to an operating agreement in which at least one working-interest owner is a third party to the operator, then the direct operating costs for that lease or property are the costs (excluding drilling costs and development costs) that are incurred by the operator in operating that lease or property and which are reimbursable to the operator by the working-interest owners, under the terms of that operating agreement.

(c) After the commencement of commercial production from (or allocated to) a lease or property, the direct operating costs for that lease or property are the costs of operating the wells, facilities and equipment on or for the lease or property which directly result in or are necessary for the continued or enhanced production from (or allocated to) the lease or property and the costs of operations conducted on or near the lease or property in support of drilling and/or development operations for the lease or property but excluding the actual drilling costs and development costs themselves; however, if the lease or property is subject to an operating agreement in which at least one working-interest owner is a third party to the operator, then the direct operating costs for that lease or property are the costs (excluding drilling costs and development costs) that are incurred by the operator in operating that lease or property and which are reimbursable to the operator by the working-interest owners, under the terms of that operating agreement.

(d) No cost for the taxpayer's general overhead or administrative expense and no cost that is to be amortized or depreciated under secs. 250 and 260 of this chapter, respectively, may be included in a deduction under this section.

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(continued)

Deduction for Direct Operating Costs — Schedule B.12

Before Commercial Production:

Submit a completed Schedule B.12 for each lease or property.

1. Geological and Geophysical Work ................................ ________
2. Rentals and Shut-In Royalties ................................ ________
3. Operational Costs in Support of Drilling and Development ................................ ________
4. Total. Add the amounts on lines 1, 2 and 3 ................................ ________

After Commencement of Commercial Production:

If the lease or property is subject to an operating agreement as described in 15 AAC 240(c), skip lines 5 through 8 and enter the total reimbursable costs on line 9.

5. Costs of Operating Wells ................................ ________
6. Costs of Operating Facilities ................................ ________
7. Costs of Operating Equipment ................................ ________
8. Operational Costs in Support of Drilling and Development ................................ ________
9. Total. Add the amounts on lines 5 - 8 ................................ ________
10. Total Direct Operating Costs. Add the amounts on lines 4 and 9 ................................ ________

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Deduction for Acquisition Costs                                        Schedule B.13

15 AAC 12.250. DEDUCTION FOR ACQUISITION COSTS. (a) A taxpayer's acquisition costs for a lease or property in the state that has never had commercial production from (or allocated to) it from any zone are deferred for purposes of this chapter until either there is commercial production from (or allocated to) it or until the lease or property is abandoned without ever having had commercial production from (or allocated to) it.

(b) If a lease or property is abandoned, then the taxpayer's unamortized acquisition costs for that lease or property are a deduction in determining the taxpayer's taxable production income for the year in which the lease or property is abandoned. If only part of the lease or property is thus abandoned, the unamortized acquisition costs for that lease or property must be apportioned to that abandoned portion on the basis of acreage.

(c) A taxpayer's acquisition costs for a lease or property having commercial production from (or allocated to) it during a year must be amortized, and the amount of amortization that year for those acquisition costs is a deduction in determining the taxpayer's taxable production income for the year. Except for cases when (d) of this section applies, the amount of amortization in a year for a lease or property equals the taxpayer's unamortized acquisition costs as of the beginning of that year, multiplied by the ratio of the Btu-equivalents of the production from (or allocated to) that lease or property during the year, to the total number of the Btu-equivalents represented by the remaining proved reserves (both developed and undeveloped) of that lease or property as of the beginning of the year.

(d) During a year it may happen that a taxpayer transfers part or all of its production interest in a commercially producing lease or property to one or more third parties or receives part or all of a production interest in a lease or property as the result of a transfer from one or more third parties. In such a case, the taxpayer receiving the production interest and the taxpayer transferring the production interest shall each calculate its respective amortization of acquisition costs for that portion of the year preceding the transfer separately from its amortization of acquisition costs for that portion of the year following the transfer; and the sum of each taxpayer's respective amortization of acquisition costs for those two portions of the year will be a deduction in determining that taxpayer's taxable production income for that year. In calculating amortization for the portion of the year preceding the date of the transfer, the taxpayer shall use the procedure prescribed in (c) of this section, except that the ratio of the Btu-equivalents of production may include only the taxpayer's production from (or allocated to) the lease or property for the portion of the year preceding the date of the production-interest transfer. For that portion of the year following the transfer, the amount of amortization equals the taxpayer's unamortized acquisition costs as of the time immediately following the production interest transfer, multiplied by the ratio of Btu equivalents of the taxpayer's production from (or allocated to) the lease or property for the portion of the year on and after the date of the transfer to the total number of Btu-equivalents represented by the taxpayer's remaining proved reserves (both developed and undeveloped) of the lease or property as of the time immediately following the production-interest transfer.

(continued)

(e) The amount of a taxpayer's unamortized acquisition costs for a lease or property as of a particular date equals the taxpayer's acquisition costs for its original production interest in the lease or property, plus the unamortized acquisition costs for each production interest in the lease or property transferred to the taxpayer on or before that date, and minus the sum of (1) the unamortized acquisition costs for each production interest in the lease or property transferred from the taxpayer on or before that date, (2) the cumulative amount (as of that date) of the taxpayer's acquisition costs for the lease or property that has been allowed under this section for amortization or abandonment, and (3) the taxpayer's standardized prior-tax amortization for the lease or property under sec. 630. of this chapter.

(f) A taxpayer amortizing its acquisition costs for a lease or property for financial accounting purposes on a basis other than a variant of unit-of-production amortization may apply to the department for authorization to use that other basis for purposes of calculating the deduction under this section. Upon a satisfactory showing that the taxpayer does use another basis for amortizing its acquisition costs for financial accounting purposes, the department may grant the requested authorization to the taxpayer. Until that authorization is granted in writing, the taxpayer shall follow the method prescribed in this section to amortize its acquisition costs for leases or properties in the state.

(g) The amount of a taxpayer's acquisition costs for a lease or property equals the taxpayer's net payments for

(1) cash bonus or comparable advance payment to acquire the lease or property;

(2) drilling costs for wells bottomed on the lease or property which were completed or abandoned no later than the completion of the discovery well for the field that includes the lease or property and which were spudded after the acquisition of the lease or property or in fulfillment of a condition or requirement to acquire or retain the lease or property;

(3) tax paid under AS 43.56 to the state (net of all credits and refunds for municipal ad valorem taxes on the same property) for property used on or for the lease or property after its acquisition and before the completion of the discovery well for the field that includes the lease or property or for property used in the drilling described in (2) of this subsection, and ad valorem and other taxes paid to one or more municipalities under AS 29.53 that were incurred for the drilling referred to in (2) of this subsection or for property or operations on or for the lease or property after its acquisition and before the completion of that discovery well;

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(continued)

Deduction for Acquisition Costs Schedule B.12(a)

(4) that portion of the full consideration given by the taxpayer in acquiring a production interest in the lease or property which is properly attributable to the acquisition of the lease or property (as opposed to the wells, facilities and equipment on or in support of the lease or property which directly result in or are necessary for continued or enhanced production from (or allocated to) the lease or property);

(5) interest on capital borrowed from one or more third parties for any of the expenditures described in (1) - (4) of this subsection that was capitalized for purposes of the taxpayer's financial accounting; however, interest so capitalized may be recognized for purposes of this chapter at a rate not to exceed the composite cost of the taxpayer's borrowed capital from third parties as reflected in the taxpayer's financial accounting for the year in which the interest is capitalized.

Property or Lease Abandoned During the Year. 15 AAC 12.250(b).

Column (a): Enter the location of the abandoned property or lease.

Column (b): Enter the total acreage in the entire property or lease.

Column (c): Enter the total acreage in the property or lease abandoned during this year.

Column (d): Divide the acreage in column (c) by the acreage in column (b). Enter the quotient as a amount (Quotient should be to six figures) in this column.

Column (e): Enter the amount of the taxpayer's unamortized acquisition costs attributable to the total lease or property acreage in column (b).

Column (f): Multiply the amount in column (e) by the amount in column (d) and enter the product in column (f):

| Line | col. (a) Abandoned Property or Lease Location | col. (b) Total Acreage In: Lease or Property | col. (c) Total Acreage In: Abandoned Lease or Property | col. (d) (c) ÷ (b) | col. (e) Unamortized Cost | col. (f) Allowable Acquisition Cost Deduction |
|---|---|---|---|---|---|---|
| 1. | | | | | | |
| 2. | | | | | | |
| 3. | | | | | | |
| 4. | | | | | | |
| 5. | | | | | | |
| 6. | Total. Add the amounts in column (f), lines 1-5 ................ | | | | | |

(Attach a separate schedule if more than five properties or leases were abandoned this year.)

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Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Deduction for Acquisition Costs — Schedule B.13(b)

DO NOT INCLUDE ON LINES 7-21 ANY EXPENSES OF A PRODUCTION INTEREST TRANSFERRED TO OR FROM THE TAXPAYER OR ANY ABANDONMENT COSTS CLAIMED ON LINE 6.

Submit a completed Schedule B.13(b) for each lease or property.

7. Cash Bonus (or comparable advance payment).
15 AAC 12.250(g)(1) .................................... ________

8. Drilling Costs for Wells Bottomed.
15 AAC 12.250(g)(2) .................................... ________

9. Taxes Paid Under AS 43.56.
15 AAC 12.250(g)(3) .................................... ________

10. Taxes Paid Under AS 29.53.
15 AAC 12.250(g)(3) .................................... ________

11. Other Consideration(s).
15 AAC 12.250(g)(4) .................................... ________

12. Interest. 15 AAC 12.250(g)(5) .......................... ________

13. Total. Add the amounts on lines 7 - 12 ........................ ________

14. Cumulative Amount of AS 43.21 Acquisition Costs Allowed.
15 AAC 12.250(b) and (e). (Attach schedule) .............. ________

15. Standardized Prior-Tax Amortization. 15 AAC 12.630 ...... ________

16. Add amounts on lines 14 and 15 ................................ ________

17. Net Acquisition Costs.
Amount on line 13 less amount on line 16 ........................ ________

18. Btu Equivalents of Production from (or allocated to)
the Lease or Property During This Tax Year .............. ________

19. Total Reserve Btu-Equivalents. 15 AAC 12.250(c) .......... ________

20. Divide the amount on line 18 by amount on line 19.
(Quotient should be to six figures) ............................ ________

21. Acquisition Cost Deduction. Amount on line 17
multiplied by the amount on line 20 ............................ ________

(continued)



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Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Reduction for Acquisition Costs — Schedule B.13(c)

Amortization of acquisition costs applicable to a commercially producing lease or property which had all or part of a production interest transferred during the period covered by this Return:

Enter on lines 22-32 expenses as of the beginning of the year for such lease or property. 15 AAC 12.250(e). Submit a completed Schedule B.13(c) for each such commercially producing lease or property. Do not include any acquisition costs attributable to any lease or property abandoned during the year.

Depreciation for Portion of Year Preceding Transfer.

22. Cash Bonus (or comparable advance payment). 15 AAC 12.250(g)(1) .................... ______
23. Drilling Costs for Wells Bottomed. 15 AAC 12.250(g)(2) .................... ______
24. Taxes Paid Under AS 43.56. 15 AAC 12.250(g)(3) .................... ______
25. Taxes Paid Under AS 29.53. 15 AAC 12.250(g)(3) .................... ______
26. Other Consideration(s). 15 AAC 12.250(g)(4) .................... ______
27. Interest. 15 AAC 12.250(g)(5) .................... ______
28. Total. Add the amounts on line 22-27 .................... ______
29. Cumulative Amount of AS 43.21 Acquisition Costs Allowed as of the Beginning of the Year 15 AAC 12.250(b) and ( ). (Attach schedule) .................... ______
30. Standardized Prior-Tax Amortization. 15 AAC 12.630 .................... ______
31. Add amounts on lines 29 and 30 .................... ______
32. Net Acquisiton Costs of Production Interest. Amount on line 28 less amount on line 31 .................... ______
33. Date and Description of Production Interest Transferred. (Attach schedule).
34. Btu-Equivalents of Production Realized from Production Interest for the Portion of the Year Preceding the Transfer. (Attach schedule) .................... ______
35. Total Btu-Equivalents of Remaining Proved Reserves (both developed and undeveloped) of the Production Interest as of the Beginning of the Year .................... ______
36. Divide the amount on line 34 by the amount on line 35. (Quotient should be to six figures) .................... ______
37. Allowable Acquisiton Costs Prior to Transfer. Multiply the amount on line 32 by the amount on line 36 .................... ______

(continued)

Deduction for Acquisition Costs | Schedule B.13(c)

Depreciation for Portion of Year Following Transfer.

Enter on lines 38-44 expenses of such Lease or Property Following the Production Interest Transfer.

38. Cash Bonus (or comparable advance payment). 15 AAC 12.250(g)(1) ........ ______
39. Drilling Costs for Wells Bottomed. 15 AAC 12.250(g)(2) ........ ______
40. Taxes Paid Under AS 43.56. 15 AAC 12.250(g)(3) ........ ______
41. Taxes Paid Under AS 29.53. 15 AAC 12.250(g)(3) ........ ______
42. Other Consideration(s). 15 AAC 12.250(g)(4) ........ ______
43. Interest. 15 AAC 12.250(g)(5) ........ ______
44. Total. Add the amounts on lines 38-43 ........ ______
45. Cumulative amount of AS 43.21 Acquisition Costs Allowed as of the Time Immediately Before the Transfer. 15 AAC 12.250 (b) and (e). (Attach schedule) ........ ______
46. Standardized Prior-Tax Amortization. 15 AAC 12.630 ........ ______
47. Add the Amounts on lines 45 and 46 ........ ______
48. Net Acquisition Costs of Production Interest. Amount on line 44 less amount on line 47 ........ ______
49. Btu-Equivalents of Production Realized from Production Interest for the Portion of the Year On and After the Transfer Date. (Attach schedule) ........ ______
50. Total Btu-Equivalents Of Remaining Proved Reserves (both developed and undeveloped) of the Production Interest as of the Time Immediately Following the Production Interest Transfer ........ ______
51. Divide the amount on line 49 by the amount on line 50. (Quotient should be to six figures) ........ ______
52. Allowable Acquisition Costs Following Transfer. Multiply the amount on line 48 by the amount on line 51 ........ ______
53. Allowable Acquisition Cost Deduction. Add the amounts on lines 37 and 52 ........ ______



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Deduction for Development Costs | Schedule B.14

15 AAC 12.260. DEDUCTION FOR DEVELOPMENT COSTS. (a) A taxpayer's development costs for a lease or property in the state that has never had commercial production from (or allocated to) it from any zone are deferred for purposes of this chapter until either there is production from (or allocated to) it or until the lease or property is abandoned without ever having had commercial production from (or allocated to) it.

(b) If a lease or property is abandoned without ever having had commercial production from (or allocated to) it, then the taxpayer's undepreciated development costs for that lease or property are a deduction in determining that taxpayer's taxable production income for the year in which the lease or property is abandoned.

(c) Except for development costs to which (d) or (e) of this section applies, a taxpayer's development costs for a lease or property having commercial production from (or allocated to) it during a year must be depreciated, and the amount of depreciation that year for those development costs is a deduction in determining the taxpayer's taxable production income for the year. The amount of depreciation in a year for a lease or property equals

(1) the average between the taxpayer's undepreciated development costs for the lease or property as of the beginning of the year and those costs as of the end of the year; multiplied by

(2) the ratio of the Btu-equivalents of the production from (or allocated to) that lease or property during the year, to the total number of the Btu equivalents represented by the remaining proved development reserves for that lease or property as of the beginning of that year.

(d) A taxpayer's undepreciated development costs for wells of a lease or property that are abandoned during a year or for facilities or equipment for the lease or property which are removed during the year are excluded from the development costs that are to be depreciated that year under (c) of this section for that lease or property. Instead, the undepreciated development costs for those wells, facilities or equipment as of the beginning of the year, offset by their salvage value (if any), are a deduction in determining the taxpayer's taxable production income for the year in which they are removed.

(continued)



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(e) During a year it may happen that a taxpayer transfers part or all of its production interest in a commercially producing lease or property to one or more third parties or receives part or all of a producing interest in a lease or property as the result of a transfer from one or more third parties. In such a case, the taxpayer receiving the production interest and the taxpayer transferring the production interest shall each calculate its respective depreciation of development costs for that portion of the year preceding the transfer separately from its depreciation of development costs for that portion of the year following the transfer; and the sum of each taxpayer's respective depreciation of development costs for those two portions of the year will be a deduction in determining that taxpayer's taxable production income for that year. In calculating depreciation for the portion of the year preceding the date of the transfer, the taxpayer shall use the procedure prescribed in (c) of this section, except that the ratio of the Btu-equivalents of production may include only the taxpayer's production from (or allocated to) the lease or property for the portion of the year preceding the date of the production-interest transfer. For that portion of the year following the transfer, the amount of depreciation equals the average of the taxpayer's undepreciated development costs as of the time immediately following the production-interest transfer and as of the end of the year multiplied by the ratio of Btu-equivalents of the taxpayer's production from (or allocated to) the lease or property for the portion of the year on and after the date of the transfer to the total number of Btu-equivalents represented by the taxpayer's remaining proved developed reserves of the lease or property as of the time immediately following the production-interest transfer.

(f) The amount of a taxpayer's undepreciated development costs for a lease or property as of a particular date equals the taxpayer's development costs as of that date for the wells, facilities and equipment for that lease or property that are then in place, minus the sum of (1) the cumulative amount (as of that date) allowed under this chapter for depreciation of the taxpayer's development costs for the lease or property and (2) the taxpayer's standardized prior tax depreciation for the lease or property under sec. 630 of this chapter.

(g) A taxpayer depreciating its development costs for a lease or property for financial accounting purposes on a basis other than a variant of unit-of-production depreciation may apply to the department for authorization to use that other basis for purposes of calculating the deduction under this section. Upon a satisfactory showing that the taxpayer does use another basis for depreciating its development costs for financial accounting purposes, the department may grant the requested authorization to the taxpayer. Until that authorization is granted in writing, the taxpayer shall follow the method prescribed in this section to depreciate its development costs for leases or properties in the state for purposes of this chapter.

(h) The amount of a taxpayer's development costs for a lease or property equals the taxpayer's net payments for

(1) drilling costs for wells drilled on or for the lease or property which were completed or abandoned after the completion of the discovery well for the field that includes the lease or property,

Deduction for Development Costs — Schedule B.14(a)

(2) development costs for facilities and equipment on or in support of the lease or property that directly result in or are necessary for continued or enhanced production from (or allocated to) the lease or property,

(3) tax paid under AS 43.56 to the state (net of all credits and refunds for municipal ad valorem taxes on the same property) for property used in the drilling described in (1) of this subsection or described in (2) of this subsection, and ad valorem and other taxes paid to one or more municipalities under AS 29.53 that were incurred directly as the result of, and in the course of, the drilling described in (1) of this subsection and/or the installation or operation of the property described in (2) of this subsection,

(4) that portion of the full consideration given by the taxpayer in acquiring a production interest in the lease or property, which is properly attributable to the wells, facilities and equipment on or in support of the lease or property which directly result in or are necessary for continued or enhanced production from (or allocated to) the lease or property (as opposed to the consideration given for the lease or property itself),

(5) interest on capital borrowed from one or more third parties for any of the expenditures described in (1) - (4) of this subsection that was capitalized for purposes of the taxpayer's financial accounting; however, interest so capitalized may be recognized for purposes of this chapter at a rate not to exceed the composite cost of the taxpayer's borrowed capital from third parties as reflected in the taxpayer's financial accounting for the year in which the interest is capitalized.

Submit a completed Schedule B.14(a) for each lease or property.

Property Abandoned During the Year. 15 AAC 12.260(b) and (d).

1. Total Undepreciated Development Costs as of the Beginning of the Year Directly Related to Leases, Properties, Facilities, Wells and/or Equipment which was Abandoned or Removed During the Year. (Attach schedule). .................... .................... ________

2. Date(s) and Location(s) of Property Abandoned. (Attach schedule)

3. Salvage Value Attributable to Line 1 Property, above. (Attach schedule).................................... ............... ________

4. Development Cost Deduction. Amount on line 1 less amount on line 3.... ________

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(continued)

## Deduction for Development Costs

Schedule D.14(b)

Submit a completed Schedule D.14(b) for each lease or property.

Enter on lines 5-9 all Alaska Development Costs, EXCEPT THOSE ATTRIBUTABLE TO A PRODUCTION INTEREST(S) WHICH WAS TRANSFERRED TO OR FROM THE TAXPAYER, AND/OR ANY LEASES, PROPERTIES, FACILITIES, WELLS, AND/OR EQUIPMENT ABANDONED OR REMOVED DURING THE YEAR.

| | (a) Amount at Beginning of Year | (b) Amount at End of Year |
|---|---|---|
| 5. Drilling Costs. 15 AAC 12.260(h)(1) ........ | | |
| 6. Development Costs. 15 AAC 12.260(h)(2) ........ | | |
| 7. Taxes. 15 AAC 12.260(h)(3) ........ | | |
| 8. Consideration. 15 AAC 12.260(h)(4) ........ | | |
| 9. Interest. 15 AAC 12.260(h)(5) ........ | | |
| 10. Total. Add amounts on lines 5-9 ........ | | |
| 11. Enter the amount on line 10, col. (a), here ........ | | |
| 12. Add line 10 column (b) and line 11 ........ | | |
| 13. Average Development Costs. Divide the amount on line 12 by 2 ........ | | |

Reductions to amount on line 13.

14. Cumulative Amount of AS 43.21 Depreciation Allowed. 15 AAC 12.260(f)(1) ........ ______

15. Standardized Prior-Tax Depreciation. 15 AAC 12.630 ........ ______

16. Add amounts on lines 14 and 15 ........ ______

17. Undepreciated Development Costs. Subtract the amount on line 16 from the amount on line 13 ........ ______

18. Btu-Equivalents of Production from (or allocated to) the Lease or Properties during the Year ........ ______

19. Total Btu-Equivalents. (Developed proved reserves only) ........ ______

20. Divide the amount on line 18 by the amount on line 19 (Quotient should be to six figures) ........ ______

21. Development Cost Deduction. Multiply the amount on line 17 by the amount on line 20 ........ ______

(continued)



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Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Deduction for Development Costs                Schedule B.14(c)

Depreciation of development costs applicable to a commercially producing lease or property which had all or part of a production interest transferred during the period covered by this Return.

Enter on lines 22-27 Alaska development costs for such lease or property. Do not include any development costs attributable to any leases, properties, facilities, wells and/or equipment abandoned or removed during the year. Submit a completed Schedule B.14(c) for each such commercially producing lease or property.

| | (a) Amount at Beginning of Year | (b) Amount Immediately Prior to Transfer Date | (c) Amount Immediately Following the Date of Transfer | (d) Amount at End of Year |
|---|---|---|---|---|
| 22. Drilling Costs. 15 AAC 12.260(h)(1) .............. | | | | |
| 23. Development Costs. 15 AAC 12.260(h)(2) .............. | | | | |
| 24. Taxes. 15 AAC 12.260(h)(3) ....... | | | | |
| 25. Consideration. 15 AAC 12.260(h)(4) .............. | | | | |
| 26. Interest. 15 AAC 12.260(h)(5) .... | | | | |
| 27. Total. Add the amounts on lines 22-26 ..................... | | | | |

28. Average Development Costs for Portion of Year Preceding Transfer. Add lines 27(a) and 27(b) then divide the sum by 2 .............................................. ______

29. Average Development Costs for Portion of Year Following Transfer. Add lines 27(c) and 27(d) then divide the sum by 2 .............................................. ______



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(continued)

Deduction for Development Costs — Schedule B.14(c)

Depreciation for Portion of Year Preceding Transfer

30. Cumulative amount of AS 43.21 Depreciation Allowed as of Beginning of the Year. 15 AAC 12.260(f)(1) ............ ________
31. Standardized Prior-Tax Depreciation. 15 AAC 12.630 ............ ________
32. Add amounts on lines 30 and 31 ............ ________
33. Undepreciated Development Costs. Subtract the amount on line 32 from the amount on line 28 ............ ________
34. Date and Description of Production Interest Transferred. (Attach schedule.)
35. Btu-Equivalents of Production for the Portion of the Year Preceding the Transfer. (Attach schedule) ............ ________
36. Total Btu-Equivalents Represented by the Taxpayer's Remaining Proved Developed Reserves of the Production Interest Immediately Prior to Transfer. 15 AAC 12.260(e) ............ ________
37. Divide the amount on line 35 by the amount on line 36. (Quotient should be to six figures) ............ ________
38. Development Costs Deductible Prior to Transfer. Multiply the amount on line 33 by the amount on line 37 ............ ________

Depreciation for Portion of Year Following Transfer

39. Cumulative amount of AS 43.21 Depreciation Allowed as of the Time Immediately Before the Transfer. 15 AAC 12.260(f)(1) ............ ________
40. Standardized Prior-Tax Depreciation. 15 AAC 12.630 ............ ________
41. Add amounts on lines 39 and 40 ............ ________
42. Undepreciated Development Costs. Subtract the amount on line 41 from the amount on line 29 ............ ________
43. Btu-Equivalents of Production for that Portion of the Year On and After the Transfer Date. (Attach schedule) ............ ________
44. Total Btu-Equivalents Represented by the Taxpayer's Remaining Proved Developed Reserves of the Production Interest Immediately Following Transfer. 15 AAC 12.260(e). (Attach schedule) ............ ________
45. Divide the amount on line 43 by the amount on line 44. (Quotient should be to six figures) ............ ________
46. Development Costs Deductible Following Transfer. Multiply the amount on line 42 by the amount on line 45 ............ ________
47. Development Costs Deductible for Production Interest Transferred During the Year. Add lines 38 and 46 ............ ________



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Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Deduction for Exploration Costs — Schedule B.15

15 AAC 12.270. DEDUCTION FOR EXPLORATION COSTS. (a) A taxpayer's costs (excluding all general overhead and administrative expense allocated to the exploration) for oil and gas exploration on land in the state before the taxpayer has any production interest in that land constitute a deduction in determining the taxpayer's taxable production income for the earlier of (1) the year in which the permit or other authorization to enter that land to conduct that exploration expires without the taxpayer's having by then acquired a production interest in that land or (2) the year the taxpayer acquires a production interest in that land; except that the drilling costs for a well drilled in the course of that exploration may be deducted in determining the taxpayer's taxable production income for only that year in which the well is completed or abandoned.

(b) A taxpayer's exploration costs incurred in a project involving land both within and outside the state and in which the taxpayer then has no production interest should be allocated on the basis of relative acreage involved in the project. The department may authorize or require such an allocation to be on another basis if that is more appropriate than using acreage.

Column (a): Enter project or activity name or other identifier.

Column (b): Enter the total geological or geophysical costs for oil or gas exploration attributable to the activity or project identified in column (a).

Column (c): Enter the total drilling costs for oil or gas exploration attributable to the activity or project identified in column (a).

Column (d): Enter the sum of the amounts in columns (b) and (c).

Column (e): Enter the number of acres (miles shot or footage drilled) in Alaska attributable to the activity or project identified in column (a).

Column (f): Enter the number of acres (miles shot or footage drilled) for the entire activity or project identified in column (a).

Column (g): Enter the quotient (to six figures) obtained by dividing the amount in column (e) by the amount in column (f).

Column (h): Enter the product obtained by multiplying the amount in column (d) by the quotient in column (g).

| | (a) Identify the Exploration Activity or Project | (b) Geological/ Geophysical Costs | (c) Drilling Costs | (d) Total, col. (b) and col. (c) | (e) Number of Acres (miles shot or footage drilled) in Alaska | (f) Total Acres (miles shot or footage drilled) in project or Activity | (g) col. (d) ÷ col. (e) | (h) Allowable Exploration Cost Deduction. col. (d) x col. (g) |
|---|---|---|---|---|---|---|---|---|
| 1. | | | | | | | | |
| 2. | | | | | | | | |
| 3. | | | | | | | | |
| 4. | | | | | | | | |
| 5. | | | | | | | | |
| 6. | | | | | | | | |
| 7. | | | | | | | | |
| 8. | | | | | | | | |
| 9. | | | | | | | | |
| 10. Total ........................................................................ | | | | | | | | |

Deduction for Uncapitalized Interest — Schedule B.16

15 AAC 12.280. DEDUCTION FOR UNCAPITALIZED INTEREST. (a) Subject to the limitation in (b) of this section, a deduction is allowed in determining a taxpayer's taxable production income during a year for interest paid to third parties by the taxpayer that year which was not capitalized by the taxpayer for financial accounting purposes.

(b) The deduction under (a) of this section for interest by a taxpayer for any year may not exceed an amount equal to the total interest of which the taxpayer is a part, multiplied by a fraction whose numerator equals the net book value (as of the end of the year) for financial accounting purposes of the taxpayer's real and tangible personal property of the type described in secs. 250 and 260 of this chapter (excluding the estimated value of the taxpayer's remaining oil and gas reserves), and whose denominator is the net book value (as of the end of the year) for financial accounting purposes of all real and tangible personal property (excluding the estimated value of remaining oil and gas reserves) worldwide of the consolidated business of which the taxpayer is a part.

Submit a completed Schedule B.16 for each lease or property.

1. Total Interest Paid by or for the Taxpayers'. 15 AAC 12.280(a) ........ ______

2. Total Interest Paid by Consolidated Business Worldwide. 15 AAC 12.280(b) ........................................... ______

3. Book Value of Taxpayers' 15 AAC 12.250 Real and Tangible Personal Property (excluding oil and gas reserves) ______

4. Book Value of Taxpayers' 15 AAC 12.260 Real and Tangible Personal Property (excluding oil and gas reserves) ______

5. Add the amounts on lines 3 and 4 and enter here ..... ______

6. Book Value of All Worldwide Real and Tangible Personal Property of the Consolidated Business (excluding oil and gas reserves) .................................. ______

7. Divide the amount on line 5 by the amount on line 6. (Quotient should be to six figures) ......................... ______

8. Multiply the amount on line 2 by the amount on line 7 and enter here: ............................................. ______

9. Uncapitalized Interest Deduction. Enter the smaller of the amounts on line 1 or line 8.............................................. ______



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Deduction for General Overhead and Administrative Expenses — Schedule B.17

15 AAC 12.290. DEDUCTION FOR GENERAL OVERHEAD AND ADMINISTRATIVE EXPENSE. (a) Subject to the limitation in (b) of this section, a deduction is allowed in determining a taxpayer's taxable production income during a year, for the taxpayer's general overhead and administrative expense during that year which is properly allocated (on the basis of personnel time sheets, office space or another basis having general currency in the oil and gas industry) to (1) operations for leases or properties in the state, (2) acquiring leases or properties in the state, or (3) exploration in the state. Where general overhead and administrative expense is properly allocat[illegible] to an activity described in the preceding sentence that is conducted both within and outside the state, that general overhead and administrative expense must be allocated to in-state activity on the basis of the relative acreage involved in that activity which is in the state; however, the department will, in its discretion, authorize or require another basis for this allocation if that other basis is more appropriate than acreage.

(b) The deduction under (a) of this section for a taxpayer's general overhead and administrative expense for any year may not exceed the lesser of

(1) an amount equal to the taxpayer's own general overhead and administrative expense worldwide during that year, multiplied by a fraction whose numerator equals the net book value (as of the end of the year) for financial accounting purposes of the taxpayer's real and tangible personal property of the type described in secs. 250 and 260 of this chapter (excluding the estimated value of the taxpayer's remaining oil and gas reserves), and whose denominator is the net book value (as of the end of the year) for financial accounting purposes of all real and tangible personal property (excluding the estimated value of remaining oil and gas reserves) worldwide of the consolidated business of which the taxpayer is a part; or

(2) an amount equal to 12 cents for each barrel of the taxpayer's gross share of oil production during that year from leases or properties in the state, plus two cents for each Mcf of the taxpayer's gross share of gas production during that year from leases or properties in the state.

(continued)



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Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Deduction for General Overhead and Administrative Expenses — Schedule B.17

Submit a completed Schedule B.17 for each lease or property.

General Overhead and Administrative Expense Attributable to Taxpayers' Leases or Properties Solely in Alaska for:

1. The Operation of Leases or Properties .................. ________
2. Acquiring Leases or Properties .................. ________
3. Exploration .................. ________
4. Total. Add the amounts on lines 1 - 3 .................. ________

If there are no General Overhead and Administrative Expenses attributable to projects conducted both within and outside Alaska, skip lines 5 - 12 and enter the amount on line 4 on line 13.

General Overhead and Administrative Expenses Attributable to Taxpayers' Leases or Properties Within and Outside Alaska (do not include any amounts included on line 4, above) for:

5. The Operation of Leases or Properties .................. ________
6. Acquiring Leases or Properties .................. ________
7. Exploration .................. ________
8. Add the amounts on lines 5, 6 and 7 .................. ________

Have you been authorized or required by the department to use another basis for allocation other than acreage? If so skip lines 9 and 10 and enter the allocation factor on line 11.

9. Alaska Acreage Attributable to Amount on Line 8 .................. ________
10. Total Acreage Attributable to Amount on Line 8 .................. ________
11. Divide the amount on line 9 by the amount on line 10. (Quotient should be to six figures) .................. ________
12. General Overhead and Administrative Costs Deductible. Multiply the amount on line 8 by the amount on line 11 .................. ________
13. Add the amounts on lines 4 and 12 and enter here .................. ________

(continued)



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Deduction for General Overhead and Administrative Expenses Schedule B.17

Limitation:

14. General Overhead and Administrative Expenses of the Consolidated Business Worldwide ............................................ ________

15. Book Value of Taxpayers' 15 AAC 12.250 Real and Tangible Personal Property (excluding oil and gas reserves) .............................. ________

16. Book Value of Taxpayers' 15 AAC 12.260 Real and Tangible Personal Property (excluding oil and gas reserves) .............................. ________

17. Add the amounts on lines 15 and 16 and enter here: ...... ________

18. Book Value of All Worldwide Real and Tangible Personal Property of the Consolidated Business (excluding oil and gas reserves) .......................................... ________

19. Divide the amount on line 17 by the amount on line 18. (Quotient should be to six figures) ........................................ ________

20. Multiply the amount on line 14 by the amount on line 19 ............ ________

21. Enter the taxpayer's share of units of production during the tax year: (a) OIL (BBLS)...... ________
(b) GAS (MCF)...... ________

22. (a) Multiply the amount on line 21 (a) by 12¢ ________
(b) Multiply the amount on line 21 (b) by 2¢ ________
(c) Total. Add the amounts on lines 22(a) and (b)........ ________

23. Deductible General Overhead and Administrative Expense. Enter the smallest of the amounts on lines 13, 20 or 22(c) ............................................................ ________



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Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Oil Pipeline Income (Loss) Schedule C

General Instruction: A completed FERC Form P containing the operating income and expense pertaining to the pipeline transportation of oil in Alaska for the period covered by this Return must be attached to this Schedule.

Enter on Line 1 the total current operating revenue from the pipeline transportation of oil in Alaska during the period covered by this Return. This income is composed of all gathering, trunk, delivery, allowance oil, storage and demurrage, rental and incidental revenue, which must agree with the total on Schedule 300 of FERC Form P, attached.

Enter on Line 2 the total current operating expenses, excluding uncapitalized interest, incurred for the pipeline transportation of oil in Alaska during the period covered by this Return. The total of these expenses must agree with the total on Schedule 320 of FERC Form P, attached.

Enter on Line 4 all uncapitalized interest paid or accrued to third parties during the period covered by this Return on borrowed capital to construct or enlarge the facilities of Alaska oil pipelines. Attach a schedule of total amounts paid or accrued to each payee.

Enter on Line 5 all taxes paid or accrued during the period covered by this Return, except federal income and Alaska oil and gas corporate income taxes, related to carrier property, operations, privileges and licenses for oil pipeline transportation activities in Alaska. Attach a schedule of total amounts paid or accrued to each payee.

Enter on Line 8 any extraordinary operating revenues or losses as detailed on Schedule C.1.

Submit a completed Schedule C for each Pipeline Company.

1. Operating Revenues. (From Schedule 300, FERC Form P) .................. ________

2. Operating Expenses. (From Schedule 320, FERC Form P) .................. ________

3. Line 1 less line 2 .................................................. ________

4. Uncapitalized Interest. (Attach schedule) .................. ________

5. Taxes. (Attach schedule) ........................................ ________

6. Total, lines 4 and 5 .................................................. ________

7. Line 3 less line 6 .................................................. ________

8. Extraordinary Oil Pipeline Operating Revenue (Loss).
(Schedule C.1, line 4) .................................................. ________

9. Taxable Oil Pipeline Income (Loss). Amount on line 7 plus or (minus) amount on line 8 .................................................. ________

Extraordinary Oil Pipeline Operating Revenue (Loss) — Schedule C.1

Submit a completed Schedule C.1 for each Pipeline Company.

Enter on Line 1 the amount of any extraordinary operating revenue or (loss) resulting from a legally allowed retroactive increase or decrease in Alaska oil pipeline transportation tariffs during the period covered by this Return. The amount of the extraordinary operating revenue or extraordinary operating loss in such a case equals the difference between the operating revenue actually received under the tariff(s) previously charged and the operating revenue that would have been received under the tariff(s) as retroactively changed, during the period to which the change applies.

Indicate the effective date(s) of any such retroactive changes and the period covered by each.

| Effective Date: | Tariff Change From | Tariff Change To | Period Covered From | Period Covered To | Volume subject to each change |
|---|---|---|---|---|---|
| | | | | | |
| | | | | | |
| | | | | | |

Enter on Line 2 the amount of any catastrophic loss(es), during the period covered by this Return, related to Alaska oil pipeline property or the pipeline transportation of oil. The amount of those extraordinary operating losses equals the pipeline's costs, unreimbursed by insurance or from one or more third parties and not included in account 570 of FERC's Uniform System of Accounts for oil pipelines for damage to pipeline property, for repayment to shippers for lost oil, and for damage or clean-up of spilled oil. These extraordinary operating losses are fully recognized for purposes of this chapter in the year when the oil is lost.

Attach an explanation describing any losses claimed.

Enter on line 3 the costs of permanently terminating operations and/or removing part or all of the facilities and equipment of a pipeline. The amount of those extraordinary operating losses in a year equals the unreimbursed termination and removal costs for the pipeline that are actually incurred that year, offset by the salvage value (if any) of the removed facilities and equipment.

Operating Revenue or (Loss) Resulting From:

1. Retroactive Tariff Increase(s) or (Decrease(s)) .............................. ________
2. Catastrophic Losses. (Attach schedule) .............................. (________)
3. Termination Costs. (Attach schedule) .............................. (________)
4. Extraordinary Oil Pipeline Operating Revenue (Loss). Add lines 1, 2 and 3 .............................. ________

Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Taxable Gas Pipeline Transportation Income (Loss) Schedule D

Submit a completed Schedule D for each Pipeline Company.

General Instructions: A completed APUC Form 2 containing the operating income and expense pertaining to the pipeline transportation of natural gas in Alaska, for the period covered by this Return, must be attached to this Schedule.

1. Taxable Gas Pipeline Income (Loss) of a Natural Gas Company Regulated on a Consolidated Basis with a Retail Sales and Distribution System in Alaska. Enter amount from line 15, Schedule D.1 .................. ________

2. Taxable Gas Pipeline Income (Loss) of a Class A or B Natural Gas Company Not Regulated on a Consolidated Basis with a Retail Sales and Distribution System in Alaska. Enter amount from line 35, Schedule D.2.................... ________

3. Taxable Gas Pipeline Income (Loss) of a Class C or D Natural Gas Company Not Regulated on a Consolidated Basis with a Retail Sales and Distribution System in Alaska. Enter amount from line 20, Schedule D.3 ............ ________

4. Taxable Gas Pipeline Transportation Income (Loss)..................... ________
Add the amounts on lines 1, 2 and 3.

Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Taxable Gas Pipeline Income (Loss) of a Natural Gas Company Regulated on a Consolidated Basis with a Retail Sales and Distribution System in Alaska. — Schedule D.1

Submit a completed Schedule D.1 for each Pipeline Company.

ENTER AMOUNTS APPLICABLE TO NATURAL GAS PIPELINE TRANSPORTATION IN ALASKA

| | FERC Account Number | Amount | |
|---|---|---|---|
| 1. Operating Revenue | 400 | X | |
| Deductions | | | |
| 2. Operating Expense | 401 | | |
| 3. Maintenance Expense | 402 | | |
| 4. Depreciation Expense | 403 | | |
| 5. Amortization of Underground Storage Land and Land Rights | 404.2 | | |
| 6. Amortization of Other Limited Term Gas Plant | 404.3 | | |
| 7. Amortization of Other Gas Plant | 405 | | |
| 8. Amortization of Gas Plant Acquisition Adjustments | 406 | | |
| 9. Amortization of Conversion Expenses | 407.2 | | |
| 10. Taxes Other than Income Taxes | 408.1 | | |
| 11. Interest on Long Term Debt | 427 | | |
| 12. Total Deductions. Add lines 2 - 11 | | | |
| 13. Line 1 less line 12 | | | |
| 14. Extraordinary Gas Pipeline Operation Revenue (loss). (Schedule D.4, line 4) | | | |
| 15. Taxable Gas Pipeline Transportation Income (loss). Line 13 plus (minus) line 14 | | | |



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Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Taxable Gas Pipeline Income (Loss) of a Class A or B Natural Gas Company Not Regulated on a Consolidated Basis with a Retail Sales and Distribution System in Alaska.

Schedule D.2

Submit a completed Schedule D.2 for each Pipeline Company.

| | FERC Account Number | Amount |
|---|---|---|
| 1. Gross Proceeds from All Gas Delivered or Sold ........................ | | |
| **Deductions** | | |
| 2. Natural Gas Wellhead ..........) Purchases (..... | 800 | |
| 3. Natural Gas Field Line ........) From (..... | 801 | |
| 4. Natural Gas Plant Outlet ......) Third (..... | 802 | |
| 5. Natural Gas Transmission Line .) Parties (..... | 803 | |
| 6. Other Gas Purchases ...........) (..... | 805 | |
| 7. Value at Point of Production of Gas Not Acquired from Third Parties ........................................ | | |
| 8. Total, lines 2-7 ............................................ | | |
| 9. Operating Revenues. Line 1 less line 8 ........................... | | |
| **Operating Deductions** | | |
| 10. Operation Supervision and Engineering ........... | 850 | |
| 11. System Control and Load Dispatching ............. | 851 | |
| 12. Communication System Expenses ................... | 852 | |
| 13. Compressor Station Labor and Expenses ........... | 853 | |
| 14. Gas for Compressor Station Fuel ................. | 854 | |
| 15. Other Fuel and Power for Compressor Stations .... | 855 | |
| 16. Mains Expenses .................................. | 856 | |
| 17. Measuring and Regulating Station Expenses ....... | 857 | |
| 18. Transmission and Compression of Gas by Others ... | 858 | |
| 19. Other Expenses .................................. | 859 | |
| 20. Rents ........................................... | 860 | |
| 21. Total Operations Deductions. Add lines 10-20........................ | | |
| **Maintenance Deductions** | | |
| 22. Maintenance Supervision and Engineering ......... | 861 | |
| 23. Maintenance of Structures and Improvements....... | 862 | |
| 24. Maintenance of Mains ............................ | 863 | |
| 25. Maintenance of Compressor Station Equipment ..... | 864 | |
| 26. Maintenance of Measuring and Regulating Station Equipment ............................ | 865 | |
| 27. Maintenance of Communications Equipment ......... | 866 | |
| 28. Maintenance of Other Equipment .................. | 867 | |
| 29. Total Maintenance Deductions. Add lines 22-28......................... | | |
| 30. Uncapitalized Interest ............................................ | | |
| 31. Taxes ............................................................. | | |
| 32. Total Deductions. Add lines 21,29,30 and 31 ........................ | | |
| 33. Line 8 less line 32 ............................................... | | |
| 34. Extraordinary Gas Pipeline Operating Revenue (loss). (Schedule D.4. line 4) .............................................. | | |
| 35. Taxable Gas Pipeline Transportation Income (loss). Line 33 plus (minus) line 34 ............................ | | |

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Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Taxable Gas Pipeline Income (Loss) of a Class C or D Natural Gas Company Not Regulated on a Consolidated Basis with a Retail Sales and Distribution System in Alaska.

Schedule D.3

Submit a completed Schedule D.3 for each Pipeline Company.

| | | FERC Account Number | | Amount |
|---|---|---|---|---|
| | **Operating Revenues** | | | |
| 1. | Gross Proceeds from All Gas Delivered or Sold .... | | | |
| 2. | Natural Gas Purchases from Third Parties ......... | 730 | | |
| 3. | Other Gas Purchases from Third Parties ........... | 731 | | |
| 4. | Value at Point of Production of Gas Not Acquired from Third Parties .................................. | | | |
| 5. | Total, lines 2-4 ........................................ | | | |
| 6. | Operating Revenues. Line 1 less line 5 ................ | | | |
| | **Deductions** | | | |
| 7. | Operation Supervision and Labor ................. | 750 | | |
| 8. | Compressor Station Fuel and Power ............... | 751 | | |
| 9. | Operation Supplies and Equipment ................ | 752 | | |
| 10. | Transmission and Compression of Gas by Others..... | 753 | | |
| 11. | Rents ............................................ | 754 | | |
| 12. | Maintenance of Mains ............................ | 755 | | |
| 13. | Maintenance of Compressor Station Equipment ...... | 756 | | |
| 14. | Maintenance of Other Plant ...................... | 757 | | |
| 15. | Uncapitalized Interest .......................... | | | |
| 16. | Taxes ............................................ | | | |
| 17. | Total Deductions. Add lines 7-16 ................... | | | |
| 18. | Line 6 less line 17 .................................. | | | |
| 19. | Extraordinary Gas Pipeline Operating Revenue (Loss). (Schedule D.4, line 4) ............................. | | | |
| 20. | Taxable Gas Pipeline Transportation Income (Loss). Line 18 plus (minus) line 19 .......................... | | | |

## Extraordinary Gas Pipeline Operating Revenue (Loss) — Schedule D.4

Submit a completed Schedule D.4 for each Pipeline Company.

Enter on Line 1 the amount of any extraordinary operating revenue or loss resulting from a legally allowed retroactive increase or decrease in Alaska gas pipeline transportation tariffs during the period covered by this Return.

The amount of the extraordinary operating revenue or extraordinary operating loss in such a case equals the difference between the operating revenue actually received under the tariff(s) previously charged and the operating revenue that would have been received under the tariff(s) as retroactively changed, during the period to which the change applies.

Indicate the effective date(s) of any such retroactive changes and the period covered by each:

| Effective Date: | Tariff Change From | Tariff Change To | Period Covered From | Period Covered To | Volume Subject to each Change |
|---|---|---|---|---|---|
| | | | | | |
| | | | | | |
| | | | | | |

Enter on Line 2 the amount of any catastrophic loss(es), during the period covered by this Return, related to Alaska gas pipeline property or the pipeline transportation of gas.

The amount of an extraordinary operating loss equals the pipeline costs, unreimbursed by insurance or from one or more third parti s and not included in the pipeline's operating expense already deducted, for damage to pipeline property, for repayment to shippers for lost gas, and for damage or clean-up resulting from the loss of the gas. Such extraordinary operating loss is fully recognized for purposes of this chapter in the year when the gas is lost.

Attach an explanation describing any loss claimed.

Enter on Line 3 the amount authorized or required by FERC to be included in account 182 (Extraordinary Property Losses) for a gas pipeline. The account 182 extraordinary property losses are fully recognized for purposes of this chapter in the year in which incurred (account 182 refers to the account of that number in both FERC's Uniform System of Accounts for Class A and B natural gas companies and the one for Class C and D natural gas companies).

Operating Revenue or (Loss) Resulting From:

1. Retroactive Tariff Increase(s) or (Decrease(s)) .......................... ________
2. Catastrophic Loss .................................................... .........(________)
3 Extraordinary Property Loss. (Account 182) ..............................(________)
4. Extraordinary Gas Pipeline Revenue (Loss). Add lines 1, 2 and 3 ....... ________



AGO 785810

Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Taxable Apportioned Income (Loss) Schedule E

15 AAC 12.510. APPORTIONABLE INCOME. A taxpayer's apportionable income for a year equals

(1) the net income (calculated without regard to any taxes on or measured by net income) worldwide of the consolidated business of which the taxpayer is a part, as determined and certified by an independent certified public accountant (or, as appropriate, the foreign counterpart of a certified public accountant, such as a chartered accountant) for purposes of reporting that year's earnings and profits to the stockholders; minus either

(2) the sum (if greater than zero) of

(A) the taxpayer's taxable production income that year under sec. 100 of this chapter,

(B) the taxpayer's taxable oil pipeline income that year under sec. 300 of this chapter, and

(C) the taxpayer's taxable gas pipeline income that year under sec. 400 of this chapter; or

(3) zero, if the sum in paragraph (2) of this section is less than or equal to zero.

1. Worldwide Net Income (Loss) of the Consolidated Business. (Attach schedule) ............ ______
2. All Taxes On or Measured By Net Income. (Attach schedule) ............ ______
3. Add the amounts on lines 1 and 2 ............ ______
4. Taxable Production Income (From Schedule B) ............ ______
5. Taxable Oil Pipeline Income (From Schedule C) ............ ______
6. Taxable Gas Pipeline Income (From Schedule D) ............ ______
7. Add the amounts on lines 4, 5 and 6 and enter here; if less than zero enter -0- ............ ______
8. Apportionable Net Income (Loss). Subtract the amount on line 7 from the amount on line 3 ............ ______
9. Property Factor. (From Schedule E.1, line 16, col. (c)) ............ ______
10. Payroll Factor. (From Schedule E.2, line 7, col. (c)) ............ ______
11. Sales Factor. (From Schedule E.3, line 8, col. (c)) ............ ______
12. Total Factors. Add the amounts on lines 9 - 11 ............ ______
13. Average Factor. Divide the amount on line 12 by 3. (Quotient should be to six figures) ............ ______
14. Taxable Apportioned Income (Loss). Multiply the amount on line 8 by the amount on line 13 (Enter also on Schedule A, line 4) ............ ______



AGO 765811

Alaska Property Factor

Schedule E.1

Instructions: Owned Real and Tangible Personal Property.

On a federal income tax basis (15 AAC 10.181(a)) enter the average original cost values of owned real and tangible personal property. Do not include leases or properties, other real property and tangible personal property in Alaska that is owned by the taxpayer and is used directly in, or is necessary for the continuation or enhancement of, exploration for oil and gas, production of oil and gas, and transportation of oil and gas by pipeline. The amount entered, however, must include all other owned properties used, available for or capable of being used in producing, directly or indirectly, income of the corporation(s) included in this return.

Include in column (a) the average original cost values of owned real and tangible personal property of the consolidated business of which the taxpayer is a part which is located in the United States but not in any state and which either

(1) is serviced or supplied from a base of operations maintained in Alaska, or

(2) relies on onshore facilities in Alaska for storage of oil or gas (or both) produced from or by that real and tangible personal property or both.

Owned Real and Tangible Personal Property.

| | col. (a) Total Within Alaska | col. (b) Total Within and Outside Alaska | col. (c) |
|---|---|---|---|
| 1. Inventories. (Attach a days-in port computation schedule, if applicable. See specific instruction 1(a), page 62)...... | | | |
| 2. Buildings........................................ | | | |
| 3. Machinery and Equipment ............. ....... | | | |
| 4. Furniture and Fixtures........................ | | | |
| 5. Delivery Equipment ............................ | | | |
| 6. Leasehold Improvements. (Attach a days in-port computation schedule, if applicable. See specific instruction 1(a), page 62)..... | | | |
| 7. Land ............................................. | | | |
| 8. Marine Vessels. (Attach a days-in port computation schedule, if applicable. See specific instruction 1(a), page 62) ......... | | | |
| 9. Other Assets. (Describe on a separate schedule)........................................ | | | |
| 10. Add the amounts on lines 1-9 and enter here. | | | |
| 11. Construction in Progress (if included in lines 1-9 above) ................................ | | | |
| 12. Total. Subtract the amount on line 11 from the amount on line 10 ........................ | | | |

(continued)



AGO 785812

Alaska Property Factor | Schedule E.1

Instructions: Rented or Leased Property.

Refer to Specific Instruction number 4, Valuation of Rented Property, and Specific Instruction 1 (a) (ii) regarding special treatment for chartered marine vessels. All rents must be capitalized by multiplying the expense by eight and they must be entered in this subsection. Do not include rents paid for leases or properties, other real property and tangible personal property in Alaska that is rented by the taxpayer and is used directly in, or is necessary for the continuation or enhancement of exploration for oil and gas, production of oil and gas, and transportation of oil and gas by pipeline. Intercompany rents must be eliminated. The amount entered, however, must include all other rented properties used, available for or capable of being used in producing, directly or indirectly, income of the corporation(s) included in this return. Include in column (a) all properties rented or leased by the consolidated business of which the taxpayer is a part which is located in the United States but not in any state and which either

(1) is serviced or supplied from a base of operations maintained in Alaska, or

(2) relies on onshore facilities in Alaska for storage of oil or gas (or both) produced from or by that rented or leased property or both.

Rented or Leased Property.

| | col. (a) Total Within Alaska | col. (b) Total Within and Outside Alaska | col. (c) |
|---|---|---|---|
| 13. Chartered Marine Vessels, capitalized. (Attach a days in port computation schedule. See specific instruction 1(a), page [illegible]) ........ | | | X |
| 14. Other Rented Property, Capitalized. (Attach schedule) ........ | | | X |
| 15. Total Capitalized Rents. Add the amounts on lines 13 and 14 ........ | | | X |
| 16. Property Factor. Add the amounts on lines 12 and 15 and enter here: ........ | | | |

(Divide the amount on line 16, column (a) by the amount on line 16, column (b). Enter the quotient, (to six figures) in column (c), and also on Schedule E, line 9.)



AGO 785813

Alaska Payroll Factor

Schedule E.2

15 AAC 12.540. PAYROLL FACTOR. A taxpayer's payroll factor for a year equals the payroll factor that year for the consolidated business of which the taxpayer is a part, as determined under the applicable methods of AS 43.19.010 (Art. IV, secs. 13 and 14), AS 43.20.072(c) and (e), and 15 AAC 10.211 -- 15 AAC 10.241; except that

(1) the numerator and denominator of the payroll factor must each be determined without reference to

(A) compensation earned by the taxpayer's employees working directly in operations on or for a lease or property in the state which directly result in or are necessary for the continued or enhanced production of oil or gas from (or allocated to) the lease or property, and

(B) compensation earned by the taxpayer's employees working directly in the in-state operations of an oil pipeline or a gas pipeline; and

(2) the numerator of the payroll factor must include compensation earned by the employees of the consolidated business of which the taxpayer is a part, who are working in the United States but not in any state and who are directly supplied from a base of operations maintained in this state.

| Enter payroll, wages, salaries, commissions and other compensation attributable to: | col. (a) Total Within Alaska | col. (b) Total Within and Outside Alaska | col. (c) |
|---|---|---|---|
| 1. Cost of Goods Sold ........................ | | | X |
| 2. Compensation of Officers .................. | | | X |
| 3. Salesmen's Salaries and Commissions ...... | | | X |
| 4. Repairs ................................... | | | X |
| 5. Operation of Marine Vessels. (Attach Days-In-Port computation schedule. See specific instruction 1(b), page 62) ...... | | | X |
| 6. Other. (Specify) .......................... | | | X |
| 7. Payroll Factor. Add the amounts on lines 1-6 and enter here: ............... | | | |

(Divide the amount on line 7, column (a) by the amount on line 7, column (b). Enter the quotient, (to six figures) in column (c), and also on Schedule E, line 10.)

Alaska Sales Factor

Schedule E.3

15 AAC 12.550. SALES FACTOR. A taxpayer's sales factor for a year equals the sales factor that year for the consolidated business of which the taxpayer is a part, as determined under the applicable methods of AS 43.19.010 (Art. IV, secs. 15 --17), AS 43.20.071(d) and (e), and 15 AAC 10.251 -- 15 AAC 10.302; except that the numerator and denominator of the sales factor must each exclude non-retail sales of oil or gas produced from (or allocated to) one or more leases or properties in the state, but only to the extent that those sales would otherwise be included in the numerator and denominator of the sales factor.

(continued)

Alaska Sales Factor

Schedule E.3

| | col. (a) Total Within Alaska | col. (b) Total Within and Outside Alaska | col. (c) |
|---|---|---|---|
| 1. Sales Delivered or Shipped to Alaska Purchasers: | | | |
| (a) Shipped from Outside Alaska .......... | | | |
| (b) Shipped from Within Alaska ........... | | | |
| Total, line 1 Add the amounts on lines 1(a) and (b) .......... | | | |
| 2. Taxpayer's Operating Revenues Attributable to Marine Vessels. (Attach a days-in-port computation schedule. See specific instruction 1(c), page 62) .......... | | | |
| 3. Sales Shipped from Alaska to: | | | |
| (a) The United States Government .......... | | | |
| (b) Purchasers in a State Where the Taxpayer Was Not Subject to a Net Income Tax or a Tax Based Upon Or Measured By Net Income .......... | | | |
| Total, line 3. Add the amounts on lines 3(a) and (b) .......... | | | |
| 4. Other Alaska Business Income Gross Receipts | | | |
| (a) Interest .......... | | | |
| (b) Dividends .......... | | | |
| (c) Rents .......... | | | |
| (d) Royalties .......... | | | |
| (e) Other. (Specify) .......... | | | |
| Total, line 4. Add the amounts on lines 4(a) - (e) .......... | | | |
| 5. Total Alaska Sales. Add the amounts on lines 1-4 .......... | | | |
| 6. Total Corporation or Consolidated Business Sales, Net of Intercompany Eliminations. (Attach schedule) .......... | | | |
| 7. Sales Factor Numerator and Denominator Reductions: (Enter the following amounts only if included on lines 5 and 6, above) Non-retail sales of oil or gas produced from (or allocated to) one or more leases or properties in the state .......... | | | |
| 8. Sales Factor. Subtract the amounts on line 7 from the amounts on lines 5 and 6 .. | | | |

(Divide the amount on line 8, column (a) by the amount on line 8, column (b). Enter the quotient, (to six figures) in column (c), and also on Schedule E, line 11.)



AGO 785816

Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Specific Instructions for Apportionment Factors.

1. Tankers and Other Marine Vessels. The property, payroll and sales factor numerator values emanating from tankers and other marine vessels must be determined as follows:

   (a) Property Factor Numerator. AS 43.20.071 (b) and (e).

      (i) Owned Marine Vessels. The numerator must be determined by multiplying the average original cost values of each vessel by the days-in-port factor of each vessel.

      (ii) Chartered Vessels. The net annual rental rate of each chartered vessel is multiplied by 8, and that product is then multiplied by the days-in-port factor of each vessel to determine the numerator value.

      (iii) The Average Original Costs of Leasehold Improvements on Board marine vessels must be multiplied by the days-in-port factor to determine the numerator value.

      (iv) Average Inventories (bunker fuel, stores, spare parts, etc.) on board each vessel must be multiplied by each marine vessel's days-in-port factor to determine the numerator value.

   (b) Payroll Factor Numerator. AS 43.20.071 (c) and (e). Compensation paid by the taxpayer to marine vessel employees must be multiplied by the days-in-port factor of each marine vessel to determine the payroll factor numerator.

   (c) Sales Factor Numerator. AS 43.20.071 (c) and (e). The taxpayer's operating revenues attributable to each marine vessel must be multiplied by the days-in-port factor of each marine vessel to determine the sales factor numerator.

   (d) Days-In-Port Factor Defined. The days in-port factor is determined by dividing the number of days-in-port in Alaska of the tanker or other vessel by the number of days-in-port everywhere. A day in-port does not include time when a vessel is tied up due to repairs, strikes or seasonal inactivity. A day-in-port occurs when the vessel is tied up to a dock or wharf or when it is anchored offshore for purposes of loading or offloading cargo. A day in-port is determined by dividing the number of hours in port by 24. AS 43.20.071.

(continued)



AGO 785817

Specific Instructions Regarding
the Apportionment Factors.

2. PROPERTY IN TRANSIT. 15 AAC 10.171 (b). Property in transit between locations of the taxpayer to which it belongs must be considered to be at the destination for purposes of the property factor. Property in transit between a buyer and seller which is included by a taxpayer in the denominator of its property factor in accordance with its regular accounting practices must be included in the numerator according to the state of destination.

3. MOBILE OR MOVABLE PROPERTY. 15 AAC 10.171(c). The value of mobile or movable property such as construction equipment, trucks or leased electronic equipment which is located within and outside of this state during the tax period must be determined for purposes of the numerator of the factor on the basis of total time within the state during the tax period.

4. VALUATION OF RENTED PROPERTY. 15 AAC 10.191 (a). Property rented by the taxpayer must be valued at eight times its net annual rental rate. The net annual rental rate for any item of rented property is the annual rental rate paid by the taxpayer for that property, less the aggregate annual sub-rental rates paid by subtenants of the taxpayer. (See sec. 202 of this chapter for special rules where the use of that net annual rental rate produces a negative or clearly inaccurate value or where property is used by the taxpayer at no charge or rented at a nominal rental rate).

   (b) Subrents are not deducted when the subrents constitute business income because the property which produces the subrents is used in the regular course of a trade or business of the taxpayer when it is producing that income. Accordingly there is no reduction in its value.

   (c) "Annual rental rate" is the amount paid as rental for property for a 12-month period (i.e., the amount of the annual rent). Where property is rented for less than a 12-month period, the rent paid for the actual period of rental constitutes the "annual rental rate" for the tax period. However, where a taxpayer has rented property for a term of 12 or more months and the current tax period covers a period of less than 12 months (due, for example, to a reorganization or change of accounting period), the rent paid for the short tax period must be annualized. If the rental term is for less than 12 months, the rent may not be annualized because of the uncertain duration when the rental term is on a month-to- month basis.

5. SPECIAL RULES. 15 AAC 10.202(a). If the subrents taken into account in determining the net annual rental rate under sec. 191 of this chapter produce a negative or clearly inaccurate value for any item of property, another method which will properly reflect the value of rented property may be required by the commissioner of revenue or requested by the taxpayer.

   In no case, however, shall such value be less than an amount which bears the same ratio to the annual rental rate paid by the taxpayer for such property as the fair market value of that portion of the property used by the taxpayer bears to the total fair market value of the rented property.

   (b) If property owned by others is used by the taxpayer at no charge or rented by the taxpayer for a nominal rate, the net annual rental rate for that property must be determined on the basis of a reasonable market rental rate for that property.

AGO 785818

Net Loss Carryovers/Carrybacks Schedule F

THIS SCHEDULE MUST BE COMPLETED IF A NET LOSS IS CLAIMED ON LINE 6 SCHEDULE A.

15 AAC 12.070. TREATMENT OF NET LOSSES REALIZED UNDER THIS CHAPTER.
(a) A taxpayer realizes a net loss under this chapter if the taxpayer's net taxable income under sec. 50 of this chapter for that year is less than zero.

(b) A taxpayer's net loss may be carried back not more than three tax years before the tax year for which it is realized (but in no event before the 1978 tax year) and may be carried forward if necessary as far as the seventh tax year following the tax year for which it is realized. This carrying back and carrying forward must be on a first-in, first-out basis; that is, the tax loss must first be carried back as an offset against the taxpayer's net taxable income, if any, for the third preceding tax year, and any remaining tax loss must next be applied as an offset against the taxpayer's net taxable income, if any, for the second preceding tax year, and so on until either the tax loss is fully used as offsets against the taxpayer's net taxable income or until it has been carried forward into the seventh year following the tax year in which the net loss is realized. Any net loss from a tax year still remaining after the seventh following tax year will be lost.

(c) If a taxpayer has net losses from more than one tax year that may be applied as offsets against the taxpayer's net taxable income for the same tax year, the net loss from the earliest of those tax years must first be applied, then the net loss from the second earliest of those tax years must be applied (assuming the earliest tax loss does not fully offset the net taxable income against which it is applied), and so on.

A TAXPAYER'S NET OPERATING LOSSES UNDER ALASKA STATUTE 43.20 ARE NOT RECOGNIZED [illegible]. 15 AAC 12.[illegible]0(d).

(continued)



AGO 785819

H

Alaska Department of Revenue
Oil and Gas Corporate Income Tax Return

Net Loss Carryovers/Carrybacks Schedule F

Computation of Loss Carryovers/Carrybacks.

Column (a): Enter the year(s) of all AS 43.21 losses (whether unapplied, partially applied or fully used) in chronological order. If a loss is being carried to more than one year, use additional lines until the loss being applied is fully absorbed.

Column (b): Enter the amount of loss by year.

Column (c): Enter the tax year(s) to which a loss has been or is being applied.

Column (d): Enter the amount of loss applied.

Column (e): Enter the unused tax loss (subtract the amount in column (d) from the amount in column (b)).

Column (f): Enter the loss claimed on this return.

| Line | col. (a) Net Loss Year | col. (b) Amount of Loss | col. (c) Year Loss Applied To | col. (d) Amount of Loss Applied | col. (e) Net Loss Remaining | col. (f) Net Loss Applied To This Return |
|---|---|---|---|---|---|---|
| 1. | | | | | | |
| 2. | | | | | | |
| 3. | | | | | | |
| 4. | | | | | | |
| 5. | | | | | | |
| 6. | | | | | | |
| 7. | | | | | | |
| 8. | | | | | | |
| 9. | | | | | | |
| Total | | | | | | |

(Enter the total of col. (f) on Schedule A, line 6.)



ACC 785 117 15

# STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF REVENUE

DIVISION OF PETROLEUM REVENUE

201 E. 9th AVENUE
ANCHORAGE, ALASKA 99501
PHONE: (907) 276-1363
(907) 277-5627

January 18, 1980

Re: Income Tax Regulations
(AS 43.21)

To Recipients of Proposed Regulations:

Proposals which would amend existing oil and gas corporate income tax regulations have been distributed to you. The most recent set of proposals followed a published notice which related that set of proposals to an earlier one distributed late in October 1979. It has come to our attention that the most recent set of proposals inadvertently dropped a couple of paragraphs contained in the earlier draft. The unintended deletions, which are obvious in the context of the proposals, are contained in proposed sections 132(b)(3) and (4), 240, and 990(31) and (32). The deleted language is attached.

We apologize for any inconvenience this has caused you.

Sincerely,

Robert M. Johnson
Director

Attachment

RMJ/rdm

AGO 785820

Proposed Regulation 132(b)(3) and (4) should read:

(3) when transportation of oil is by a tanker or other vessel that is owned or effectively owned by the taxpayer of that oil, the taxpayer's actual cost for that transportation, which is the sum of:

(A) voyage and port costs incurred with respect to that transportation;

(B) the positioning cost, amortized over 36 months, for that vessel but only for placing that vessel into position before its employment in the Alaska trade and not for placing it into position after its employment in the Alaska trade for employment in another trade,

(C) depreciation of the vessel; if the vessel is actually owned by the taxpayer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for such owned assets; if the vessel is effectively owned by the taxpayer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(D) an amount, which when added to the amount of depreciation allowed under (C) of this paragraph, will provide a reasonable return on the acquisition cost of the vessel over its expected life; for purposes of this paragraph,

(i) "acquisition costs" means the cost of the vessel which may be capitalized by its actual owner under generally accepted accounting principles, but not including costs of improvements made after the date the vessel is placed in service by or on behalf of the taxpayer, and

(ii) "expected life" means the period of time used to calculate depreciation under (C) of this paragraph;

(4) in the case of transportation of gas as LNG

(A) where not all of the LNG transportation facilities are subject to tariff regulations (by FERC or other agencies of the United States, state or territory or a possession of the United States or a foreign nation) and when the taxpayer does not have or effectively have any ownership interest in the LNG transportation facility, the amount charged to the taxpayer for that LNG transportation;

(B) when the taxpayer has or effectively has an ownership interest in the LNG transportation facility, the taxpayer's actual cost for that transportation equalling the sum of:

(i) the direct operating costs of the LNG transportation facility (in the case of an LNG tanker, its respective voyage and port costs) incurred with respect to the taxpayer's gas;

(ii) the positioning cost, amortized over 36 months, for that vessel but only for placing that vessel into position before its employment in the Alaska trade and not for placing it into position after its employment in the Alaska trade for employment in another trade;

(iii) depreciation of the LNG transportation facility; if the facility is actually owned by the taxpayer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for the owner of such assets; if the LNG transportation facility is effectively owned by the taxpayer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(iv) an amount which, when added to the amount of depreciation allowed under (iii) of this subparagraph, will provide a reasonable return on the acquisition cost of the LNG transportation facility over its expected life; for purposes of this subparagraph, "acquisition cost" means the cost of the LNG transportation facility which may be capitalized by its actual owner under generally accepted accounting principles, and "expected life" means the period of time used to calculate depreciation under (iii) of this subparagraph;

Proposed Regulation 240 should read:

15 AAC 12.240. DEDUCTION FOR DIRECT OPERATING COSTS. (a) The direct operating costs during a year that are incurred by or for a taxpayer for a lease or property in the state are a deduction in determining the taxpayer's taxable production income for that year.

(b) Before the commencement of commercial production from (or allocated to) a lease or property, the direct operating costs for that lease or property are:

(1) the costs for geological and geophysical work conducted on the lease or property after the taxpayer has acquired a working interest in the lease or property;

(2) rentals and shut-in royalties paid in order to retain the lease or property;

(3) drilling costs for wells bottomed on the lease or property; and

(4) the costs for operations conducted on or near the lease or property in support of drilling and/or development operations for the lease or property, but excluding the actual development costs themselves; however, if the lease or property is subject to an operating agreement in which at least one working-interest owner is a third party to the operator, the direct operating costs for that lease or property and the costs (excluding development costs but including drilling costs) that are incurred by the operator in operating that lease or property and which are reimbursable to the operator by the working-interest owners, under the terms of that operating agreement.

(c) After the commencement of commercial production from (or allocated to) a lease or property, the direct operating costs for that lease or property are:

(1) the costs of operating the facilities and equipment on or for the lease or property which directly result in or are necessary for the continued or enhanced production from (or allocated to) the lease or property;

(2) the costs of drilling and/or operating wells bottomed on the lease or property; and

(3) the costs of operations conducted on or near the lease or property in support of drilling and/or development operations for the lease or property but excluding the actual development costs themselves; however, if the lease or property is subject to an operating agreement in which at least one working-interest owner is a third party to the operator, then the direct operating costs for that lease or property are the costs (excluding development costs but excluding drilling costs) that are incurred by the operator in operating that lease or property and which are reimbursable to the operator by the working interest owners, under the terms of that operating agreement.

(d) No cost for the taxpayer's general overhead or administrative expense and no cost that is to be amortized or depreciated under secs. 250-260 of this chapter may be included in this section.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, sec. 18)
AS 43.21.020
AS 43.21.090

Proposed Regulation 900(31) and (32) should read:

(31) "sales delivery point" means

(1) for a taxpayer's oil and gas sold in a bona fide, arm's-length sale to a third party, the point of delivery under the terms of the contract or agreement for that sale, except in the cause of a sale to which Sec. 132(d) of this chapter applies;

(2) for a taxpayer's oil not sold in a bona fide, arm's-length sale to a third party, th gate of the refinery to which that oil is ultimately transported; and

(3) for a taxpayer's gas not sold in a bona fide, arm's-length sale to a third party, the point of delivery under the terms of the sales contract being used as the reference for the sales price of the taxpayer's gas under Secs. 122 and 124 of this chapter.

(32) "sales price" is defined in Sec. 122 of this chapter.

Thomas K. Williams, Commissioner
Department of Revenue

December 4, 1979

Robert M. Johnson, Director
Petroleum Revenue Division

Required Annual Report
on Income Tax

Attached for your review and recommended use are letters to the Legislature setting out an annual report of the Oil and Gas Corporate Income Tax required under AS 43.21.110(a). The report consists of text and a chart, and should presumably be sent around January 1, 1980, although no specific date is set by law.

Attachments

RMJ/rdm

STATE OF ALASKA

DEPARTMENT OF REVENUE

DIVISION OF PETROLEUM REVENUE

JAY S. HAMMOND, GOVERNOR

201 E 9th AVENUE
ANCHORAGE, ALASKA 99501
PHONE (907) 276 1363
(907) 277 5627

December 3, 1979

The Honorable Clem V. Tillion
President of the Senate
Alaska State Legislature
Pouch Y
Juneau, Alaska 99811

Oil and Gas Corporate
Income Tax Act

Dear Sir:

Pursuant to AS 43.21.110(a), I am transmitting to you an annual consolidated report of State revenues and taxation policies under the Oil and Gas Corporate Income Tax Act (AS 43.21).

The amounts reported here and collected during 1979 relate to obligations arising during Tax Year 1978. The total amounts paid by corporations under the Act and the aggregate income and deductions are set out in the attached chart.

With respect to policies under the Act during 1979, the Department has promulgated an extensive set of regulations implementing the statutes. See, 15 AAC 12.001 et seq. Modifications to certain of those regulations have been proposed. Audits of corporations subject to the Act have commenced. The Act itself is the subject of litigation in the case of ARCO et al v. State, Superior Crt No. 3 AN 79-1903.

I hope this information is usef to you.

Sincerely,

Thomas K. Williams
Commissioner

Attachment

TKW/RMJ/rdm

AGO 785833

# STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF REVENUE

DIVISION OF PETROLEUM REVENUE

201 E. 9th AVENUE
ANCHORAGE, ALASKA 99501
PHONE (907) 276-1363
(907) 277-5627

December 3, 1979

The Honorable Terry Gardiner
Speaker of the House
Alaska State Legislature
Pouch Y
Juneau, Alaska 99811

Oil and Gas Corporate
Income Tax Act

Dear Sir:

Pursuant to AS 43.21.110(a), I am transmitting to you an annual consolidated report of State revenues and taxation policies under the Oil and Gas Corporate Income Tax Act (AS 43.21).

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With respect to policies under the Act during 1979, the Department has promulgated an extensive set of regulations implementing the statutes. See, 15 AAC 12.001 et seq. Modifications to certain of those regulations have been proposed. Audits of corporations subject to the Act have commenced. The Act itself is the subject of litigation in the case of ARCO et al v. State, Superior Crt No. 3 AN 79-1903.

I hope this information is useful to you.

Sincerely,

Thomas K. Williams
Commissioner

Attachment

TKW/RMJ/rdm

AGO 785834

04-07LH

Attachment A

| | | . . Activity in Thousands of Dollars . . . . . . | | | |
|---|---|---|---|---|---|
| | | Production | Pipeline | Apportioned[1] | Total |
| 1. | Gross Income | $5,512,723 | $2,384,714 | $17,305,523 | $25,202,960 |
| 2. | Deductions | 4,605,205 | 1,623,201 | 17,250,301 | 23,478,707 |
| 3. | Taxable Income | $ 907,518 | $ 761,513 | $ 55,222 | $ 1,724,253 |
| 4. | Total Tax | | | | $ 170,393[2] |
| 5. | Less: | | | | |
| | Payments | | | | 172,112 |
| | Credits | | | | 2,899 |
| 6. | Total Payments and Credits | | | | 175,011 |
| 7. | Taxes Overpaid (line 6 - line 4) | | | | 4,618 |
| 8. | Less: | | | | |
| | Amounts Applied To 1979 Estimated Tax | | | | 2,277 |
| 9. | Remainder Refunded To Taxpayers (line 7 - line 8) | | | | $ 2,341 |

(1) The gross income reported in this column is total apportionable taxable income and the deductions represent the amount apportioned to jurisdictions other than the State of Alaska.

(2) The effective tax rate for 1978 is 9.88%, which is greater than the statutory rate of 9.4%. Because this is so, some taxpayers reported losses in 1978. Since a carryback period is not available to these taxpayers at this time, the tax impact attributable to these losses will be realized in some period subsequent to 1978. *See*, AS 43.21.020(d).

AGO 785835

Joseph K. Donohue, Deputy Commissioner
Department of Revenue

October 29, 1979

Robert M. Johnson, Director
Petroleum Revenue Division

Impact of Allowing Intangible Drilling Expenses as a Direct Deduction

You have asked for an a alysis of the financial impact of allowing intangible drilling costs (IDCs) as a deduction to derive taxable production income under the Oil and Gas Corporate Income Tax Act (AS 43.21).

As you know, drilling costs (intangible or tangible) incurred by oil and gas producers are not specifically allowed as an operating expense deduction in deriving taxable production income. Intangible drilling costs are, howev r, an allowable deduction under § 263 of the Internal Revenue Code. Prior to enactment of the Oil and Gas Corporate Income Tax (AS 43.21), § 263 was incorporated by reference into the Net Income Tax Act (AS 43.20) which applied to the oil and gas producers. That incorporation by reference disappeared with enactment of AS 43.21. The law does not now specifically address IDCs, but does permit as deductions to derive oil and gas production income such items as dry hole expenses, interest expense not capitalized by the corporation up to a certain amount, and amortization of lease acquisitions. See, AS 43.21.020(b). Under the original regulations implementing that provision, "drilling costs" may be deducted to derive taxable production income only as a portion of acquisition and development costs. Those allowable costs are limited. 15 AAC 12.250 and 12.260. Operating expenses, which are generally deductible to the full extent of the expenses incurred, exclude "drilling costs."

The Department is presently proposing to promulgate regulations which would allow IDCs, as a drilling cost, to be directly deducted as an operating expense.1/ Such a change in regulations would impose a significant impact on taxes received. Our preliminary calculation of taxes paid under AS 43.21 indicates that, as an example, the 1978 tax base of $1,780,402,000 would drop by $672,653,000 or 38%.2/ The taxes produced would consequently drop by a similar percentage or approximately $63,596,000. While the tax benefit to the covered taxpayers is a decrease in tax obligations of 38% industry wide, some taxpayers, depending on their unique circumstances, would stand to save over 100% of their tax obligations (resulting in a net operating loss) while others would see only minor savings. However, a weighted average among all taxpayers clearly places the bulk of the tax savings at between 30 and 40%, as noted.

1/ Whether a regulation alone can permit this change is the subject of an opinion request to the Attorney General.

2/ Because of the nature of reporting taxes, the estimates of IDCs are based only on those reported under development cost deductions. 15 AAC 12.260. There also may be IDCs claimed under the present acquisition cost deductions (15 AAC 12.250) but these figures cannot be readily extracted. However, for purposes of calculating impact, the percentage figures, ratios and adjusted tax receipts would remain about the same as estimated or would show a slightly greater benefit for the taxpayer.

# ALASKA STATE LEGISLATURE - HOUSE OF REPRESENTATIVES

REPRESENTATIVE JOE McKINNON
POUCH V, JUNEAU, ALASKA 99811

February 4, 1980

Thomas K. Williams, Commissioner
Department of Revenue
Pouch S
Juneau, Alaska 99811

Dear Tom:

Re: Proposed changes to 15 AAC 12; regulations on the Oil and Gas Corporate Income Tax

We are very concerned, as you know, over the proposed changes to the regulations on the Oil and Gas Corporate Income Tax (15 AAC 12). We urge you to postpone any action on these regulation changes until we have had more time to review them. Our specific concerns are the proposed changes to sections 240, 250 and 260, which provide for the direct deduction of drilling costs as operating costs. We are also concerned about allowing methods other than unit-of-production depreciation, which is the method specifically mentioned in the statutes.

During deliberations over the Oil and Gas Corporate Income Tax legislation, the Department of Revenue relied on work by Jerome M. Zeifman and Kenneth G. Ainsworth. In their January 1977 report entitled <u>The Taxation of the Petroleum Industry Under Alaska's Corporate Income Tax</u>, Ziefman and Ainsworth cite two major problems. The first was what they called an "eroded tax base". This was due to Federal tax subsidies historically provided to the petroleum industry. The second problem was that Alaska was using an apportionment formula, which did not fairly reflect the true amount of business being done in the state.

Both these problems stemmed from the fact that Alaska had delegated to Congress the responsibility for determining the corporate income tax base. By adopting certain provisions of the Internal Revenue Code, the State was inadvertantly adopting Federal deductions designed as tax subsidies. The most notable of these, as Ziefman and Ainsworth pointed out, was the "expensing of intangible drilling costs." Furthermore, by adopting an apportionment formula based on the Uniform Division of Income for Tax Purposes Act, the State was not taxing the petroleum industry on a manner which truly reflected their profits made in the State. The effect, as stated by Richard Kilgore of the Walter J. Levy Consultants Corporation before a joint House-Senate Resources Committee hearing on March 21, 1977, was "an effective rate of taxation instead of something like 9.4% a rate of taxation, roughly a quarter of that, two to two and a half percent."

That the intent of SCS CSHB 322 was to solve both of these problems is clear. In a letter dated July 5, 1978 to the House Speaker and Senate President, Governor Hammond wrote:

> Oil and gas corporations have been paying an effective tax rate substantially below the nominal tax rate of 9.4 per cent and substantially below what other local corporations would pay on the same income earned on the same assets in the state. The passage of this bill culminates three years of joint effort by the executive and legislative branches to rectify substantial defects in the former taxation scheme which, by incorporating various federally available tax loopholes and by using an inappropriate apportionment formula, allowed oil and gas corporations to avoid their fair share of the state tax burden. (1978 House Journal Final Supplement, p. 13).

To now reincorporate the "federally available tax loophole" of expensing of intangible drilling costs by regulation appears to be directly in conflict with the intent of AS 43.21. (ch 110 SLA 1978).

Plus, the fact that this proposed change to the regulations is of questionable legality is evident in the request for a legal opinion from Joseph K. Donohue, Deputy Commissioner of Revenue to Wilson Condon, Deputy Attorney General, dated November 2, 1979. The Department of Revenue claims the question of law centers around an interpretation of AS 43.21.020(c)(4), which defines operating expenses allowed as direct deductions. Under AS 43.21.020(c)(4), there is no specific reference to drilling costs. The Department has apparently mistakenly concluded that if drilling cost are not indirect costs, they may be deducted.

We would like to bring to the Department's attention AS 43.21.020(c)(8) which provides the only reference in the statutes which directly relates to "drilling costs." This subsection explicitly states that "dry hole" costs are allowed as direct deductions. We emphasize here that this apples only to "dry hole" costs and not drilling costs per se.

Returning to the legislative history on taxes in general, it is clear that SCS CSHB 322 was not the first attempt to rid the state tax base of "federally available tax loopholes." On February 25, 1975, Governor Hamm . wrote to the House Speaker regarding HB 208:

> I am submitting this bill for the purpose of closing certain corporate tax loopholes. The bill would eliminate the foreign tax credit, the depletion allowance, and the exemptions for domestic international sales corporations (DISC), and would place a limit on the amount of investment credit for Alaska income tax purposes. (1975 House Journal 295).

After the passage of CSHB 208 (Fi .. am S (ch 153 SLA 1975), the only other significant "tax loophole" left was expensing of intangibles.

We understand that a large measure of your concern arises from the current lawsuit over AS 43.21. We believe that many of the complaints in the lawsuit can be rendered moot by changes to the statutes which will have little impact on revenue. We remind you of the letter the Attorney General wrote to Governor Hammond on June 22, 1978, in which Avrum Gross concluded, that:

> We herefore simply reiterate our advice to the Department of Revenue and state that, in our view there are no constitutional or legal issues which would be fatal to the implementation of the new income tax.

I think you can understand our concerns. We are available at any time to discuss them with you further, and also to work with you on statutory changes to which address substantive legal points concerning the lawsuit over AS 43.21. Please send us a copy of the latest annual consolidated report of state revenues and taxation policies required under AS 43.21.110.

Sincerely,

Joe

Joe McKinnon

cc: Joseph K. Donohue, Deputy Commissioner of Revenue
Rob Johnson, Director, Div. of Petroleum Revenue
Representative Terry Gardiner
Representative Russ Meekins

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

**DEPARTMENT OF REVENUE**

*DIVISION OF PETROLEUM REVENUE*

201 E. 9th AVENUE
ANCHORAGE, ALASKA 99501
PHONE (907) 276-1363
(907) 277-5627

January 31, 1980

The Honorable Joseph H. McKinnon
Alaska House of Representatives
Pouch Y, State Capitol
Juneau, Alaska 99811

Attn: Bob Williams

Re: Income Tax Regulations

Dear Sir:

Attached as requested by your staff is a copy of statements submitted by the petroleum industry at recent hearings on Oil and Gas Corporate Income Tax regulations.

Sincerely,

Robert M. Johnson
Director

Attachments

RMJ/rdm

04-D7LH

AGO 785836

COMMENTS BY MARK I. HAZELWOOD
ON BEHALF OF THE ALASKA OIL AND GAS ASSOCIATION
AT HEARINGS ON PROPOSED ALASKA OIL AND GAS CORPORATE
INCOME TAX REGULATIONS
ANCHORAGE, ALASKA
JANUARY 24, 1980

## INTRODUCTION

MY NAME IS MARK L. HAZELWOOD AND I AM AN ATTORNEY IN THE TAX DEPARTMENT OF ATLANTIC RICHFIELD COMPANY. I HAVE BEEN REQUESTED BY THE ALASKA OIL AND GAS ASSOCIATION (AOGA) TO PRESENT THE ASSOCIATION'S VIEWS REGARDING THE PROPOSED REGULATIONS ISSUED BY THE DEPARTMENT OF REVENUE ON DECEMBER 17, 1979 TO AMEND EXISTING REGULATIONS UNDER CHAPTER 21 OF TITLE 43 OF THE ALASKA STATUTES, THE ALASKA OIL AND GAS CORPORATE INCOME TAX.

INASMUCH AS THE ALASKA INCOME TAX HAS A SIGNIFICANT IMPACT ON OUR INDUSTRY'S ACTIVITIES IN THE STAT WE TRU T THAT OUR TESTIMONY AT THIS HEARING WILL EVIDENCE OUR CONTINUING INTEREST AND CONCERN NOT ONLY WITH RESPECT TO THE SUBJECT MATTER COVERED IN THE PROPOSED REGULATIONS BUT ALSO ALL OTHER ASPECTS OF THE OIL AND GAS CORPORATE INCOME TAX.

AOGA RECOGNIZES THE DIFFICULTIES ASSOCIATED WITH IMPLEMENTING THIS TAX LAW, CONSIDERING ITS UNIQUE AND COMPLEX NATURE, AND COMMENDS YOUR EFFORTS TO DRAFT AND ADOPT, WITHIN THE PARAMETERS OF THE EXISTING LAW, WELL-REASONED REGULATIONS. WE WELCOME THE OPPORTUNITY TO PRESENT OUR VIEWS AT THIS HEARING AND HOPE THAT OUR COMMENTS AND SUGGESTIONS WILL BE OF ASSISTANCE TO THE

DEPARTMENT IN PROMULGATING FINAL REGULATIONS.

THE ASSOCIATION, BY PARTICIPATING IN THIS HEARING, DOES NOT CONCEDE, HOWEVER, THAT THE CORPORATE INCOME TAX LAW AS ENACTED IN CHAPTER 21 IS CONSTITUTIONAL OR OTHERWISE LEGAL. IN OUR OPINION, CHAPTER 21 AS ENACTED IS UNCONSTITUTIONAL BECAUSE IT RESULTS IN IMPERMISSIBLE DUPLICATIVE TAXATION AND AN IMPROPER BURDEN ON INTERSTATE COMMERCE IN VIOLATION OF THE COMMERCE CLAUSE OF THE UNITED STATES CONSTITUTION AND BECAUSE IT VIOLATES THE RESTRICTIONS ON EXTRATERRITORIAL TAXATION EMBODIED IN THE DUE PROCESS CLAUSE OF THE FOURTEENTH AMENDMENT OF THE UNITED STATES CONSTITUTION AND ARTICLE I, SECTION 7 OF THE ALASKA CONSTITUTION. FURTHERMORE, WE BELIEVE CHAPTER 21 UNLAWFULLY DISCRIMINATES AGAINST MEMBERS OF THIS ASSOCIATION BY SUBJECTING THEM TO A METHOD OF TAXATION MORE BURDENSOME THAN THAT IMPOSED ON ANY OTHER INDUSTRY IN THE STATE THEREBY VIOLATING THE EQUAL PROTECTION OF THE LAWS AND THE DUE PROCESS CLAUSES OF THE UNITED STATES AND ALASKA CONSTITUTIONS. ACCORDINGLY, OUR COMMENTS AND SUGGESTIONS ARE OFFERED WITH THE UNDERSTANDING THAT PARTICIPATION IN THIS HEARING WILL NOT PREJUDICE ANY RIGHTS OF THE ASSOCIATION OR ANY OF ITS MEMBERS IN ANY COURT OR OTHER PROCEEDING TO CONTEND THAT CHAPTER 21 AND THE REGULATIONS ADOPTED PURSUANT THERETO ARE UNCONSTITUTIONAL OR INVALID.

AOGA's objective at this hearing is to assist the Department in the development of regulations which (1) would result in a fair and equitable interpretation of the statute consistent with legislative intent, (2) would promote ease of administration to allow each taxpayer to discharge its income tax liability with a reasonable degree of certainty based on information available to the taxpayer and (3) would avoid the prospect of further controversy between our industry and the State of Alaska.

Most of our testimony today will be devoted to comments and suggested changes pertaining to specific sections of the proposed regulations. We do not intend, however, to address in our oral testimony suggested word changes which are believed not to be of a controversial or substantive nature.

Before turning to the proposed regulations, we first would like to make two comments relative to our overall assessment of the proposed regulations. First, AOGA is deeply concerned about certain proposed changes to the determination of gross value at the point of production for a taxpayer's oil and gas. The proposed regulations present serious questions concerning (1) the concept of prevailing value as employed by the Department especially with respect to its scope of application, and (2) the potential taxation of artificially created income in contravention of well-established principles of state income

TAXATION. SUCH SERIOUS QUESTIONS, IF LEFT UNADDRESSED, INVITE CONTROVERSY AND INCREASE THE POTENTIAL OF FUTURE LITIGATION. WE BELIEVE CHANGES CAN BE MADE TO ELIMINATE THESE POTENTIAL PROBLEMS IN A MANNER WHICH IS CONSISTENT WITH THE UNDERLYING INTENT OF THE STATUTE AND WITH THE BEST INTERESTS OF BOTH THE STATE AND OUR INDUSTRY.

SECOND, AOGA IS ENCOURAGED BY THE DEPARTMENT'S ACTION IN PROPOSING REGULATIONS WHICH SPECIFICALLY AUTHORIZE DEDUCTIONS FROM BOTH GROSS PRODUCTION INCOME AND PIPELINE OPERATING REVENUES SIMILAR TO DEDUCTIONS ALLOWED TAXPAYERS UNDER CHAPTER 20, TITLE 43 OF THE ALASKA STATUTES. THIS IS CONSISTENT WITH THE STATUTE AND REPRESENTS A SIGNIFICANT STEP TOWARD MITIGATING THE DISCRIMINATORY TAXATION TO WHICH THE OIL AND GAS INDUSTRY CURRENTLY IS SUBJECTED EVEN THOUGH SUCH PROPOSALS AFFECT ONLY THE TIMING OF PAYMENT BUT NOT THE TOTAL AMOUNT OF TAXES ULTIMATELY TO BE PAID TO THE STATE OF ALASKA.

FOR THE CONVENIENCE OF THE DEPARTMENT, WE WOULD LIKE TO PRESENT COPIES OF OUR SUGGESTED CHANGES TO THE PROPOSED REGULATIONS AT THIS TIME. COPIES OF OUR TESTIMONY WILL BE FURNISHED AT THE CONCLUSION OF THIS PRESENTATION.

THIS CONCLUDES OUR INTRODUCTORY REMARKS AND I NOW WOULD LIKE TO BEGIN OUR DETAILED TESTIMONY WITH SECTION 120, "VALUE AT THE POINT OF PRODUCTION."

## SECTION 120

WE BELIEVE THAT SUBSECTION (A) OF SECTION 120 IS NOT NECESSARY AND IS SOMEWHAT MISLEADING AND CONFUSING IN THE CONTEXT OF AN INCOME TAX. ACCORDINGLY, WE ARE SUGGESTING THAT IT BE DELETED AND THE SUBSEQUENT SUBSECTIONS RE-LETTERED.

THE GENERAL APPROACH OF THE REGULATIONS IS TO BEGIN WITH THE PRICE OR OTHER VALUE IN THE MARKET AND NET BACK TO THE POINT OF PRODUCTION BY AN ALLOWANCE FOR TRANSPORTATION COSTS AND, IN THE CASE OF GAS, CERTAIN OTHER COSTS. SUBSECTION (B) OF THE PROPOSED REGULATIONS REFLECTS THIS GENERAL APPROACH WHERE THE VALUE IS BASED ON THE SALES PRICE. IN THE DEPARTMENT'S PROPOSED REGULATIONS, PREVAILING VALUE AT THE POINT OF USE MAY BE SUBSTITUTED FOR SALES PRICE UNDER CERTAIN CIRCUMSTANCES. WE BELIEVE THAT APPROPRIATE LANGUAGE SHOULD BE INSERTED IN PARAGRAPH (1) TO REFLECT THE NETBACK CONCEPT IN SITUATIONS WHERE PREVAILING VALUE IS USED. OUR SUGGESTED LANGUAGE IS CONTAINED IN THE INDUSTRY DRAFT YOU HAVE BEFORE YOU.

A BRIEF EXPLANATION OF OUR SUGGESTED LANGUAGE IS IN ORDER. UNDER THE PROPOSED REGULATIONS, PREVAILING VALUE IS DETERMINED AT THE POINT OF USE OF THE OIL IN THE REFINING PROCESS. ANY NETBACK NECESSARILY MUST REFLECT TRANSPORTATION COSTS FROM THE POINT OF PRODUCTION TO THE POINT OF USE. IT WILL NOT ALWAYS BE TRUE THAT THE POINT OF DELIVERY BY THE SELLER WILL BE THE POINT

OF USE. THUS, IT IS NECESSARY THAT THE REASONABLE COSTS OF TRANSPORTATION ADJUSTMENT BE WORDED TO REFLECT A PROPER ALLOWANCE FOR ALL TRANSPORTATION, WHETHER PAID FOR BY THE SELLER OR ANOTHER PARTY. A SIMPLE EXAMPLE WILL ILLUSTRATE. IN A THIRD PARTY SALE CALLING FOR DELIVERY AT THE PORT OF VALDEZ THE PRICE THE PURCHASER WOULD PAY WOULD TAKE INTO ACCOUNT HIS COST OF TRANSPORTATION FROM THAT POINT TO THE INLET OF THE REFINERY. LIMITING THE COST OF TRANSPORTATION ADJUSTMENT TO TRANSPORTATION FROM THE WELL TO VALDEZ CLEARLY WOULD NOT ADEQUATELY REFLECT ALL TRANSPORTATION COSTS FROM THE POINT OF PRODUCTION TO THE INLET OF THE REFINERY. WE BELIEVE THE SUGGESTED LANGUAGE WILL APPROPRIATELY PERMIT A PROPER ADJUSTMENT FOR ALL TRANSPORTA ION.

THE TAX IMPOSED UNDER CHAPTER 21 IS GENERALLY RECOGNIZED AS AN INCOME TAX. WE SEE NO REASON OR STATUTORY BASIS FOR THE FLOOR INSERTED AS PARAGRAPH (2) IN THE PROPOSED REGULATION. WE FURTHER BELIEVE THAT ITS INCLUSION WOULD RAISE SERIOUS CONSTITUTIONAL IMPLICATIONS IN VIEW OF THE NATURE OF THIS TAX. ACCORDINGLY, WE SUGGEST THAT IT BE STRICKEN.

WE TURN NOW TO ONE OF THE MOST IMPORTANT PARTS OF OUR PRESENTATION TODAY, NAMELY THE CONCEPT OF PREVAILING VALUE AND ITS PLACE, IF ANY, IN THE ADMINISTRATION OF AN INCOME TAX LAW. SUBSECTION (C) OF THE PROPOSED REGULATIONS ADDRESSES THE QUESTION OF WHEN PREVAILING VALUE APPLIES.

WE CANNOT URGE TOO STRONGLY OUR BELIEF THAT PREVAILING VALUE AS A CONCEPT HAS NO PLACE IN INCOME TAX LAW. THE TAX, UNDER CHAPTER

21, WHICH IS IMPOSED AS AN INCOME TAX, MUST BE BASED IN ALL INSTANCES ON INCOME ACTUALLY REALIZED BY THE TAXPAYER AND NOT ON ARTIFICIALLY CREATED INCOME. WE ARE PARTICULARLY CONCERNED ABOUT THE APPLICATION OF ANY SUCH STANDARD AS PREVAILING VALUE ON A HINDSIGHT BASIS YEARS AFTER THE FACT. THIS IS PARTICULARLY TRUE IN TODAY'S MARKET WHERE PRICES MOVE RAPIDLY AND PROBABLY NOT IN ANY DISCERNABLE AND EASILY DEFINED PATTERN. WE BELIEVE THAT ANY SIGNIFICANT RELIANCE ON PREVAILING VALUE RAISES SUBSTANTIAL CONSTITUTIONAL QUESTIONS.

THE ASSOCIATION RECOGNIZES, HOWEVER, THAT THE DEPARTMENT IS CHARGED WITH THE RESPONSIBILITY OF PROMULGATING REGULATIONS WHICH DETERMINE A UNIFORM METHOD OF ESTABLISHING GROSS VALUE AT THE POINT OF PRODUCTION, AND THAT ONE OF THE OPTIONS AFFORDED BY THE GOVERNING LEGISLATION IS TO CONSIDER PREVAILING PRICE OR VALUE. IF PREVAILING VALUE IS TO BE RECOGNIZED IN THE REGULATIONS AT ALL, ITS USE SHOULD BE ON AN EXCEPTION BASIS ONLY. WE ARE CONCERNED, HOWEVER, THAT YOUR LANGUAGE MAY BE APPLIED INDISCRIMINATELY AND RESULT, FOR EXAMPLE, IN THE EXAMINATION OF EVERY TRANSACTION AGAINST A HYPOTHETICAL PREVAILING VALUE STANDARD. THE RESULT WOULD BE ENDLESS DISPUTES WITH TAXPAYERS ON A TRANSACTION BY TRANSACTION BASIS IRRESPECTIVE OF WHETHER THE TAXPAYER HAS FULLY AND CORRECTLY RECORDED AND REPORTED ITS REALIZATION FROM THE TRANSACTION.

THE PROPOSED REGULATIONS RELY ON A TWO PART TEST, WHICH

INVOLVES (I) A PRICE SUBSTANTIALLY LOWER THAN THE DEPARTMENT'S DETERMINATION OF PREVAILING VALUE AT THE POINT OF USE AND (II) THE EXISTENCE OF ONE OF FOUR CONDITIONS. WE DO NOT BELIEVE THAT THE FIRST THREE CONDITIONS REPRESENT REALISTIC TESTS. FURTHERMORE, AS PREVIOUSLY MENTIONED, WE FEEL THAT YOUR PROPOSAL WILL, IN APPLICATION, CAUSE YOUR AUDITORS TO TEST TRANSACTIONS AGAINST THE PREVAILING VALUE STANDARD AND THEN TO DETERMINE WHETHER ONE OF THE FOUR CONDITIONS APPLIES OR MIGHT APPLY. THIS APPROACH IS UNREALISTIC AND SHOULD BE OF ADMINISTRATIVE CONCERN TO THE DEPARTMENT.

THE ASSOCIATION IS CONVINCED THAT THE STATE WOULD BE ADEQUATELY PROTECTED BY LANGUAGE PERMITTING THE APPLICATION OF PREVAILING VALUE ONLY WHERE THE CIRCUMSTANCES SHOW FRAUD OR AN INTENT TO EVADE TAXES. AOGA'S SUGGESTED CHANGES SO PROVIDE.

WE RECOGNIZE THE DEPARTMENT'S RESPONSIBILITY TO AUDIT A TAXPAYER'S RETURN AND TO DETERMINE THAT THE RETURN PROPERLY REFLECTS THE AMOUNTS ACTUALLY REALIZED IN THE TAXPAYER'S TRANSACTIONS. AOGA IS CONCERNED, HOWEVER, THAT IF THE APPLICATION OF THE REGULATIONS GOES BEYOND ACTUAL REALIZATION OF INCOME AND THUS VIOLATES THE CONCEPTS OF INCOME TAXATION, THERE WILL BE FREQUENT AND SERIOUS CONFLICTS BETWEEN THE INDUSTRY AND THE STATE.

OUR FINAL COMMENT WITH RESPECT TO SECTION 120

RELATES TO SUBSECTION (D). THE SAME LANGUAGE IS CONTAINED IN SECTION 110 OF THE EXISTING REGULATIONS. TO AVOID DUPLICATION WE SUGGEST THAT SUBSECTION (D) BE STRICKEN.

## SECTION 122

THE ASSOCIATION HAS NO COMMENTS WITH RESPECT TO SECTION 122 OF THE PROPOSED REGULATIONS OTHER THAN THE SUGGESTED TECHNICAL CHANGE AT THE END OF SUBSECTION (B)(1).

## SECTION 124

AS WE STATED EARLIER IN OUR TESTIMONY, THE BASIC CONCEPT EMPLOYED IN THE REGULATIONS IS TO DETERMINE GROSS VALUE AT THE POINT OF PRODUCTION BY A NETBACK FROM THE POINT OF SALE OR USE. PREVAILING VALUE IS A SUBSTITUTE FOR SALES PRICE AND ITS DETERMINATION SHOULD NOT INVOLVE A NETBACK CALCULATION. TO CONFORM WITH SECTION 122, AND TO BE CONSISTENT WITH THIS CONCEPT, WE SUGGEST THAT THE LANGUAGE RELATING TO REASONABLE COSTS OF TRANSPORTATION IN SUBSECTIONS (A) AND (B) OF THE PROPOSED REGULATIONS BE DELETED.

## SECTION 130

SECTION 130 OF THE PROPOSED REGULATIONS SPECIFIES TWO METHODS FOR DETERMINING THE REASONABLE COSTS OF TRANSPORTATION WHICH MAY BE DEDUCTED IN ARRIVING AT THE GROSS VALUE AT THE

POINT OF PRODUCTION. EXCEPT IN UNUSUAL CIRCUMSTANCES, THE PROPOSED REGULATIONS WILL LIMIT THE TAXPAYER'S TRANSPORTATION DEDUCTION TO THE ACTUAL COSTS DETERMINED UNDER SECTION 132. IN CASES WHERE THE UNUSUAL CONDITIONS SET FORTH IN SECTION 130(B) EXIST, THE TRANSPORTATION DEDUCTION WILL BE THE FAIR MARKET VALUE OF SUCH TRANSPORTATION DETERMINED IN THE MANNER PRESCRIBED IN SECTION 132. AS A PRACTICAL MATTER, ACTUAL COSTS WILL BE REQUIRED TO BE USED IN MOST, IF NOT ALL, CASES.

WE BELIEVE THAT TAXPAYERS SHOULD BE PERMITTED AN ELECTION TO USE FAIR MARKET VALUE IN LIEU OF ACTUAL COSTS. OUR PROPOSED LANGUAGE WOULD PROVIDE THE TAXPAYER WITH AN ELECTION WHICH COULD BE CHANGED ONLY UPON APPROVAL BY THE DEPARTMENT. WE THINK THIS CHANGE IS NECESSARY TO PREVENT THE INCOME (OR LOSS) OF THE TAXPAYER'S MARINE TRANSPORTATION OPERATIONS FROM IMPROPERLY INCREASING (OR DECREASING) THE GROSS VALUE AT THE POINT OF PRODUCTION. THE INCLUSION OF VALUE ADDED BY MARINE TRANSPORTATION IN THE GROSS VALUE AT THE POINT OF PRODUCTION IS INCONSISTENT WITH THE SEPARATE ACCOUNTING CONCEPT FOR TAXATION OF OIL AND GAS PRODUCTION INCOME UNDER CHAPTER 21.

THE PROVISION FOR A REASONABLE RATE OF RETURN ON THE ACQUISITION COST OF A VESSEL OVER ITS EXPECTED LIFE DOES NOT, IN AND OF ITSELF, REFLECT THE CURRENT INCOME ATTRIBUTABLE TO A VESSEL'S OPERATION. FURTHERMORE, THE INCLUSION OF VESSEL FACTOR DATA IN THE FACTORS USED TO APPORTION ALL OTHER INCOME

OF THE TAXPAYER SIMPLY COMPOUNDS THE INEQUITY. OUR PROPOSED LANGUAGE WOULD PROVIDE A TAXPAYER WITH AN ELECTION TO ADOPT THE FAIR MARKET VALUE APPROACH TO AVOID INCLUDING ANY INCOME (OR LOSS) ATTRIBUTABLE TO MARINE TRANSPORTATION IN THE GROSS VALUE AT THE POINT OF PRODUCTION CALCULATION AND WOULD HELP TO REDUCE FUTURE CONTROVERSIES IN THIS AREA. WHILE THE ARGUMENT FOR SUCH AN ELECTION HAS BEEN MADE BEFORE IN A PRODUCTION TAX CONTEXT, THE PRINCIPLE IS EVEN MORE SOUND IN AN INCOME TAX CONTEXT.

## SECTION 132

WITH RESPECT TO SECTION 132 OF THE REGULATIONS, WE HAVE SEVERAL CHANGES TO SUGGEST. AOGA BELIEVES THE LIMITING LANGUAGE IN SUBPARAGRAPH (B) OF SUBSECTION (B)(3) SHOULD BE REMOVED BECAUSE IT IS NEITHER LOGICAL NOR EQUITABLE TO LIMIT POSITIONING COSTS TO ONE SIDE OF A TRANSACTION IF THE TAXPAYER IS OBLIGATED BY THIRD PARTY CONTRACT TO PAY POSITIONING COSTS UPON CESSATION OF USE OF A VESSEL IN THE ALASKA TRADE. MOREOVER, THE LANGUAGE WHICH WE SUGGEST BE DELETED IS INCONSISTENT WITH THE DEFINITION OF THE TERM "POSITIONING COST" SET FORTH IN SUBSECTION (G).

IN SUBPARAGRAPH (D)(I) OF SUBSECTION (B)(3), THE ASSOCIATION FEELS IT IS IMPORTANT THAT THE WORDS "BUT NOT", WHICH EXPRESSLY PROHIBIT THE INCLUSION OF COSTS OF IMPROVEMENTS IN THE DEFINITION OF "ACQUISITION COSTS", BE DELETED. TO DIFFERENTIATE BETWEEN ACQUISITION COSTS AND COSTS OF IMPROVEMENTS FOR PURPOSES OF CALCULATING DEPRECIATION AND RETURN ON INVESTMENT IS ILLOGICAL, INEQUITABLE AND INCONSISTENT WITH THE STATE'S

POLICY OF ENCOURAGING, IF NOT MANDATING, THE RETROFITTING AND FURTHER IMPROVEMENT OF TANKERS USED IN THE ALASKA TRADE. THIS PROVISION NOT ONLY DENIES THE TAXPAYER A RETURN ON ITS INVESTMENT IN IMPROVEMENTS, BUT ALSO DENIES THE TAXPAYER ANY DEPRECIATION ON THOSE IMPROVEMENTS BECAUSE OF THE INTERRELATIONSHIP OF THE DEPRECIATION AND RATE OF RETURN PROVISIONS OF THE REGULATIONS. WE CAN SEE NO RATIONALE FOR EXCLUDING THESE COSTS FROM THE CALCULATION OF REASONABLE TRANSPORTATION COSTS AND URGE THE REMOVAL OF THE LIMITATION. UNDER OUR SUGGESTED LANGUAGE, ANY DEPRECIATION OR RETURN ON INVESTMENT ALLOWED THE TAXPAYER WOULD BE LIMITED TO THAT WHICH IS ATTRIBUTABLE SOLELY TO THE EMPLOYMENT OF THE VESSEL IN THE ALASKA TRADE. FOR THE SAME REASONS NOTED ABOVE, WE HAVE INSERTED SIMILAR SUGGESTED CHANGES TO THE PROVISIONS COVERING THE TRANSPORTATION OF LNG.

WITH RESPECT TO SUBSECTION (C) OF SECTION 132, WE SUGGEST THAT THE TERMS "AND (C)" BE ADDED FOLLOWING THE REFERENCE TO SECTION 130(B) TO CONFORM WITH OUR EARLIER SUGGESTION REGARDING THAT SECTION. WE ALSO SUGGEST THAT THE REGULATIONS PROVIDE THAT THE DEPARTMENT MAY AUTHORIZE TAXPAYERS TO USE ONE OF THE TWO METHODS FOR DETERMINING THE FAIR MARKET VALUE OF LIKE TRANSPORTATION. IN OUR PROPOSED SUBPARAGRAPH (A), WE HAVE ADDED LANGUAGE THAT WOULD MAKE CLEAR THAT THE THIRD PARTY CHARTERS UTILIZED FOR COMPARISON PURPOSES WOULD BE CHARTERS OF "LIKE VESSELS". IN OUR PROPOSED SUBPARAGRAPH (B), WE ARE SUGGESTING THE ADDITION OF AN ALTERNATIVE APPROACH WHICH WOULD UTILIZE

RATES PUBLISHED BY THE ASSOCIATION OF SHIPBROKERS AND AGENTS, U.S.A., INC. WE BELIEVE EITHER OF THESE STANDARDS SHOULD BE AVAILABLE FOR USE, WITH THE PERMISSION OF THE DEPARTMENT, IN DETERMINING FAIR MARKET VALUE FOR MARINE TRANSPORTATION.

SECTION 240

IN PRIOR HEARINGS, THE ASSOCIATION HAS ADVOCATED THAT COSTS INCURRED FOR AND IN SUPPORT OF DRILLING CONSTITUTE PROPER ITEMS OF DIRECT OPERATING COSTS UNDER THE STATUTE. WE ARE PLEASED TO NOTE THAT SECTION 240 OF THE PROPOSED REGULATIONS EXPRESSLY AUTHORIZES DEDUCTION OF THESE COSTS. WITH RESPECT TO SECTION 240(c) AS PROPOSED, WE HAVE SUGGESTED THE ADDITION OF TWO ITEMS TO BE INCLUDED AS DIRECT OPERATING COSTS AFTER COMMENCEMENT OF COMMERCIAL PRODUCTION. IN THE ASSOCIATION'S SUGGESTED LANGUAGE, THESE APPEAR AS PARAGRAPHS (1) AND (2) OF SECTION 240(c).

PARAGRAPH (1) SIMPLY ADDS THE COSTS OF GEOLOGICAL AND GEOPHYSICAL WORK CONDUCTED ON THE LEASE OR PROPERTY AND IS, IN ESSENCE, SIMPLY AN EXTENSION OF THE SAME TYPE OF DEDUCTION ALLOWED UNDER SUBSECTION(B)(1) WHEN SUCH WORK IS DONE PRIOR TO COMMENCEMENT OF COMMERCIAL PRODUCTION. WE SEE NO REASON FOR ALLOWING THESE TYPES OF COSTS BEFORE COMMERCIAL PRODUCTION COMMENCES WHILE NOT ALLOWING THEM AFTER COMMERCIAL PRODUCTION COMMENCES. ALTHOUGH IT IS PROBABLY TRUE THAT MOST OF THIS TYPE OF WORK OCCURS PRIOR TO THE COMMENCEMENT OF COMMERCIAL PRODUCTION, IT IS NOT UNCOMMON FOR A TAXPAYER TO ENGAGE IN "G&G" WORK ON A LEASE OR PROPERTY TO TEST CONDITIONS FOR OTHER POTENTIAL PRODUCTION THAT MIGHT EXIST AT DIFFERENT DEPTHS OR IN DIFFERENT AREAS FROM THE EXISTING PRODUCTION.

PARAGRAPH (2) OF SECTION 240(c) MERELY ADDS RENTALS

AND SHUT-IN ROYALTIES AS A DEDUCTIBLE COST. THE PROVISION BEING ADDED IS IN FACT IDENTICAL TO THE LANGUAGE OF PARAGRAPH (2) OF SECTION 240(B). AS IN THE CASE OF "G&G" WORK, WE SEE NO REASON WHY THIS ITEM SHOULD NOT ALSO BE DEDUCTIBLE AFTER COMMENCEMENT OF COMMERCIAL PRODUCTION. A LEASE AGREEMENT COULD PROVIDE FOR SHUT-IN ROYALTIES AND, WHILE IT MAY NOT BE A VERY COMMON SITUATION, THESE COULD BECOME PAYABLE IN THE EVENT OF AN EXTRAORDINARY SHUT-DOWN OF PRODUCTION.

OTHER THAN THE TWO CHANGES JUST NOTED, OUR DRAFT MAKES VERY MINOR CHANGES IN WORDING TO THE REMAINDER OF PROPOSED SECTION 240(C).

## SECTION 250

ALTHOUGH SECTION 250 WAS NOT CONTAINED IN THE PROPOSED REGULATIONS, AOGA IS SUGGESTING THE ADDITION OF LANGUAGE TO SECTION 250(G)(2). EXCEPT FOR THE WORDS "NOT DEDUCTED UNDER SEC. 240 OF THIS CHAPTER", THIS PROVISION IS IDENTICAL TO SECTION 250(G)(2) OF THE EXISTING REGULATIONS. THIS PROVISION, WITH THE ADDED WORDS, HAS BEEN INSERTED TO ENSURE THAT ANY DRILLING COSTS NOT DEDUCTED UNDER SECTION 240 WILL REMAIN AS A PART OF THE "ACQUISITION COSTS" OF A LEASE OR PROPERTY AND BE SUBJECT TO A DEDUCTION FOR ABANDONMENT OR AMORTIZATION UNDER SECTION 250.

# SECTION 260

SECTION 260 OF THE PROPOSED REGULATIONS PERTAINS TO THE DEDUCTION FOR DEVELOPMENT COSTS. SUBSECTION (c) OF THE REGULATION PROVIDES THAT AFTER THE COMMENCEMENT OF COMMERCIAL PRODUCTION THE TAXPAYER'S DEVELOPMENT COSTS FOR A LEASE OR PROPERTY MUST BE DEPRECIATED. THE PROPOSED REGULATIONS CONTAIN SEVERAL CHANGES IN THE METHODOLOGY HERETOFORE ALLOWED IN DETERMINING THE TAXPAYER'S DEPRECIATION DEDUCTION FOR DEVELOPMENT COSTS. THESE PROPOSED CHANGES ARE CONSISTENT WITH THE AUTHORITY GRANTED THE DEPARTMENT UNDER A.S. 43.21.020(c)(5). ALTHOUGH WE ARE SUPPORTIVE OF THE DEPARTMENT'S OBJECTIVES IN MAKING THE PROPOSED CHANGES, WE OFFER THE FOLLOWING COMMENTS AND SUGGESTIONS FOR YOUR CONSIDERATION.

IT FIRST SHOULD BE RECOGNIZED THAT, ALTHOUGH THE DEDUCTION FOR DEPRECIATION IS DERIVED FROM A MATHEMATICAL FORMULA, THERE ARE A MYRIAD OF INTRICACIES RELATING TO THE APPLICATION OF SUCH A FORMULA THAT CAN LEAD TO COMPLEX PROBLEMS. ACCORDINGLY, EXTREME CARE MUST BE EXERCISED SO AS TO ENSURE THAT INTENDED RESULTS ARE ACHIEVED. AS WRITTEN, THE PROPOSED REGULATION COULD LEAD TO UNINTENDED RESULTS. FOR EXAMPLE, THE REGULATIONS CORRECTLY DESCRIBE THE MANNER OF COMPUTING DEPRECIATION UNDER THE UNIT OF PRODUCTION, SUM OF THE YEARS-DIGITS, DOUBLE DECLINING BALANCE AND STRAIGHT-LINE METHODS OF DEPRECIATION. HOWEVER, THESE METHODS, WHEN USED IN

CONJUNCTION WITH THE OTHER PROVISIONS OF SECTION 260, POSE SIGNIFICANT PROBLEMS.

ONE PROBLEM ARISES FROM THE FACT THAT THE PROPOSED REGULATION IMPLICITLY, IF NOT EXPLICITLY, PROVIDES FOR A SINGLE OPEN-ENDED COMPOSITE ACCOUNT FOR PURPOSES OF COMPUTING DEPRECIATION. A COMPOSITE ACCOUNT IS ONE WHICH INCLUDES ALL THE ASSETS OF A BUSINESS IN ONE DEPRECIATION ACCOUNT. THE COMPOSITE ACCOUNT PROVIDED FOR IN THE PROPOSED REGULATIONS IS OPEN-ENDED BECAUSE IT INCLUDES ON A CUMULATIVE BASIS DEVELOPMENT COSTS THAT MAY HAVE BEEN INCURRED OVER SEVERAL TAXABLE YEARS. THE USE OF AN OPEN-ENDED COMPOSITE ACCOUNT CAN LEAD TO SUBSTANTIAL PROBLEMS IN DETERMINING THE DEPRECIATION DEDUCTIONS ALLOWED UNDER THE SUM OF THE YEARS-DIGITS, DOUBLE DECLINING BALANCE AND STRAIGHT-LINE METHODS OF DEPRECIATION BECAUSE THE ESTIMATED REMAINING LIFE OF THE COMPOSITE ACCOUNT IS CONSTANTLY CHANGING. FURTHERMORE, THE USE OF AN OPEN-ENDED ACCOUNT CAN RESULT IN MUCH HIGHER DEPRECIATION DEDUCTIONS THAN DEDUCTIONS CALCULATED USING CLOSED-END ACCOUNTS. A CLOSED-END OR "VINTAGE" COMPOSITE ACCOUNT IS AN ACCOUNT WHICH WOULD INCLUDE ALL OF THE TAXPAYER'S DEVELOPMENT COSTS FIRST ELIGIBLE FOR DEPRECIATION IN A PARTICULAR TAXABLE YEAR.

AS AN EXAMPLE OF THE DIFFERENCES BETWEEN THE TWO TYPES OF ACCOUNTS, ASSUME THAT A TAXPAYER HAD AT THE BEGINNING OF THE TAXABLE YEAR $1,000 OF DEVELOPMENT COSTS WHICH WERE FULLY DEPRECIATED AND THAT DURING THE TAXABLE YEAR HE INCURRED

AN ADDITIONAL $200 OF DEVELOPMENT COSTS WHICH WERE ELIGIBLE FOR DEPRECIATION. IN DETERMINING THE TAXPAYER'S DEPRECIATION DEDUCTION USING THE STRAIGHT-LINE METHOD AND ASSUMING A 10-YEAR USEFUL LIFE, THE DEPRECIATION WOULD BE CALCULATED AS FOLLOWS:

(1) IF AN OPEN-ENDED ACCOUNT IS USED, THE AVERAGE ORIGINAL DEVELOPMENT COSTS IN THE DEPRECIATION ACCOUNT WOULD AMOUNT TO $1100 WHICH IS THEN MULTIPLIED BY A 10% DEPRECIATION RATE, PROVIDING A DEPRECIATION DEDUCTION OF $110 IN THE FIRST YEAR BASED ON ONLY AN ADDITIONAL $200 OF DEPRECIABLE DEVELOPMENT COSTS.

(2) IF A CLOSED-END DEPRECIATION ACCOUNT IS USED, THE AVERAGE ORIGINAL DEVELOPMENT COSTS IN THE CURRENT YEAR VINTAGE ACCOUNT WOULD EQUAL $100 WHICH WHEN MULTIPLIED BY THE 10% DEPRECIATION RATE PROVIDES A DEDUCTION OF $10 IN THE FIRST YEAR.

THUS, THE EXAMPLE ILLUSTRATES THAT UNDER CERTAIN CIRCUMSTANCES THE USE OF AN OPEN-ENDED RATHER THAN A CLOSED-END DEPRECIATION ACCOUNT CAN RESULT IN SIGNIFICANTLY GREATER AMOUNTS OF DEPRECIATION.

ALTHOUGH THE USE OF AN OPEN-ENDED COMPOSITE ACCOUNT YIELDS GREATER DEPRECIATION DEDUCTIONS, THE ASSOCIATION RECOGNIZES THAT THIS RESULT IS UNINTENDED AND SUGGESTS THAT THE PROPOSED REGULATIONS SHOULD BE CHANGED. ACCORDINGLY, SECTION 260(D) OF AOGA'S SUGGESTED CHANGES PROVIDES THAT EACH TAXPAYER MUST ESTABLISH A CLOSED-END VINTAGE ACCOUNT FOR DEVELOPMENT COSTS FIRST ELIGIBLE FOR DEPRECIATION DURING THE TAXABLE YEAR. "DEVELOPMENT COSTS FIRST ELIGIBLE FOR

DEPRECIATION" DURING A PARTICULAR TAXABLE YEAR WOULD INCLUDE (1) DEVELOPMENT COSTS PAID OR INCURRED DURING THAT YEAR WITH RESPECT TO A LEASE OR PROPERTY THAT HAD COMMERCIAL PRODUCTION FROM (OR ALLOCATED TO) IT AND (2) DEVELOPMENT COSTS PAID OR INCURRED IN PRIOR TAXABLE YEARS WITH RESPECT TO A LEASE OR PROPERTY THAT FIRST HAD COMMERCIAL PRODUCTION FROM (OR ALLOCATED TO) IT DURING THAT TAXABLE YEAR.

AS AN ILLUSTRATION, SUPPOSE A TAXPAYER INCURS DEVELOPMENT COSTS ELIGIBLE FOR DEPRECIATION OF $10 MILLION IN 1982 AND $20 MILLION IN 1983. FOR THE TAXABLE YEAR 1982, THE TAXPAYER WOULD CALCULATE DEPRECIATION FOR ITS 1982 VINTAGE ACCOUNT BASED ON $10 MILLION OF DEVELOPMENT COSTS. FOR THE TAXABLE YEAR 1983, THE TAXPAYER WOULD CALCULATE DEPRECIATION SEPARATELY FOR THE 1982 VINTAGE ACCOUNT BASED ON $10 MILLION OF DEVELOPMENT COSTS AND FOR THE 1983 VINTAGE ACCOUNT BASED ON $20 MILLION OF DEVELOPMENT COSTS. IF THE TAXPAYER INCURRED $30 MILLION OF DEVELOPMENT COSTS IN 1984 FOR A LEASE OR PROPERTY WHICH WOULD NOT HAVE COMMERCIAL PRODUCTION FROM (OR ALLOCATED TO) IT UNTIL 1985, THE $30 MILLION WOULD FALL IN THE 1985 VINTAGE ACCOUNT FOR PURPOSES OF CALCULATING THE TAXPAYER'S DEPRECIATION.

ANOTHER PROBLEM PERTAINING TO THE CALCULATION OF DEPRECIATION USING A METHOD PRESCRIBED IN SECTION 260(C) AND AN OPEN-ENDED COMPOSITE ACCOUNT WILL OCCUR WHEN THE TAXPAYER

CHANGES ITS METHOD OF COMPUTING DEPRECIATION UNDER SECTION 260(D). THE EXAMPLE IN THE PROPOSED REGULATIONS MAKES IT CLEAR THAT IN SWITCHING TO THE STRAIGHT-LINE METHOD, IT IS INTENDED THAT THE TAXPAYER USE ITS AVERAGE ORIGINAL DEVELOPMENT COSTS IN DETERMINING ITS DEPRECIATION DEDUCTION. SUCH A DEDUCTION WOULD GREATLY EXCEED THAT WHICH WOULD BE CALCULATED USING THE UNDEPRECIATED BALANCE OF THE ACCOUNT DEPRECIATED OVER ITS REMAINING USEFUL LIFE. ACCORDINGLY, SECTION 260(E) OF AOGA'S SUGGESTED CHANGES PROVIDES, IN PART, THAT WHEN A CHANGE OF METHOD IS MADE FOR A VINTAGE ACCOUNT, ONLY THE TAXPAYER'S UNDEPRECIATED DEVELOPMENT COSTS (OFFSET BY SALVAGE VALUE, IF ANY) SHALL BE RECOVERED OVER THE REMAINING USEFUL LIFE OF THAT ACCOUNT USING THE NEW METHOD OF DEPRECIATION.

AOGA FURTHER RECOMMENDS IN SECTION 260(E) OF ITS SUGGESTED CHANGES THAT THE TERM "SALVAGE VALUE" BE DEFINED AS THE AMOUNT ESTIMATED TO BE REALIZABLE UPON THE DISPOSITION OF AN ASSET WHEN IT IS NO LONGER USEFUL IN THE TAXPAYER'S TRADE OR BUSINESS AND IS TO BE RETIRED FROM SERVICE BY THE TAXPAYER, BUT ONLY TO THE EXTENT THAT THE ESTIMATED SALVAGE VALUE OF A VINTAGE ACCOUNT EXCEEDS AN AMOUNT EQUAL TO 10% OF THE ORIGINAL DEVELOPMENT COSTS FOR THAT VINTAGE ACCOUNT. THE 10% ADJUSTMENT TO ESTIMATED SALVAGE VALUE IS INTENDED TO REDUCE CONFLICTS BETWEEN TAXPAYERS AND THE DEPARTMENT INASMUCH AS OUR EXPERIENCE INDICATES THAT MOST ASSETS USED IN ALASKA HAVE AN ESTIMATED

SALVAGE VALUE OF LESS THAN 10% AT THE TIME THEY ARE RETIRED FROM SERVICE. THIS SALVAGE ADJUSTMENT IS SIMILAR TO ONE CURRENTLY AFFORDED TAXPAYERS UNDER CHAPTER 20.

THE PROPOSED REGULATIONS DO NOT PROVIDE A DEPRECIABLE LIFE FOR DEVELOPMENT COSTS, WHICH IS ESSENTIAL TO THE CALCULATION OF DEPRECIATION UNDER THE STRAIGHT-LINE, SUM OF THE YEARS-DIGITS AND DOUBLING DECLINING BALANCE METHODS OF DEPRECIATION. AOGA RECOMMENDS IN SECTION 260(F) OF ITS SUGGESTED CHANGES THAT THE DEPRECIABLE LIFE BE DETERMINED BY USING THE LOWER LIMIT ASSET DEPRECIATION RANGE GUIDELINE LIFE SET FORTH IN IRS REVENUE PROCEDURE 77-10 (AS AMENDED OR SUPERSEDED) FOR THE ASSET GUIDELINE CLASS PERTAINING TO ASSETS USED IN THE EXPLORATION FOR AND PRODUCTION OF PETROLEUM AND NATURAL GAS DEPOSITS. WE FEEL THAT REFERENCE TO THIS REVENUE PROCEDURE IS APPROPRIATE INASMUCH AS IT CURRENTLY IS BEING USED TO DETERMINE USEFUL LIFE BY CHAPTER 20 TAXPAYERS. SECTION 260(F) OF OUR SUGGESTED CHANGES FURTHER PROVIDES THAT IF REVENUE PROCEDURE 77-10 (AS AMENDED OR SUPERSEDED) IS NULLIFIED DUE TO THE IMPLEMENTATION OF A FEDERAL CAPITAL COST RECOVERY ALLOWANCE, THE DEPRECIABLE LIFE FOR PURPOSES OF CALCULATING DEPRECIATION FOR DEVELOPMENT COSTS WOULD BE THE CAPITAL RECOVERY PERIOD THAT WOULD APPLY TO CHAPTER 20 TAXPAYERS FOR SIMILAR ASSETS.

SECTIONS 260(G) AND (I) OF AOGA'S SUGGESTED CHANGES ADD BACK REFERENCES TO DRILLING COSTS SO AS TO ALLOW EITHER AN ABANDONMENT LOSS DEDUCTION OR A DEPRECIATION DEDUCTION FOR

DRILLING COSTS OR COSTS RELATED TO DRILLING WHICH WERE NOT DEDUCTED UNDER SECTION 240 OF THE PROPOSED REGULATIONS. THIS IS CONSISTENT WITH OUR SUGGESTED CHANGES TO THE DEFINITION OF ACQUISITION COSTS UNDER SECTION 250 OF THE PROPOSED REGULATIONS.

AOGA HAS RECOMMENDED CHANGES IN SECTION 260(H) OF ITS SUGGESTED CHANGES TO MAKE IT CLEAR THAT, IN THE CASE OF A TRANSFER OF A PRODUCTION INTEREST OR PROPERTY DURING THE TAXABLE YEAR, THE TAXPAYER IS TO CALCULATE DEPRECIATION FOR THE PORTION OF THE YEAR PRIOR TO THE TRANSFER AND FOR THE PORTION OF THE YEAR AFTER THE TRANSFER USING ONE OF THE METHODS OF DEPRECIATION PRESCRIBED IN SECTION 260(G). FURTHERMORE, OUR SUGGESTED CHANGE IS DESIGNED TO MAKE IT CLEAR THAT PARAGRAPHS (1) AND (2) UNDERLYING SECTION 260(H) APPLY ONLY TO A TAXPAYER USING THE UNIT OF PRODUCTION METHOD OF DEPRECIATION.

SECTION 260(H) OF THE PROPOSED REGULATIONS HAS LIMITED APPLICABILITY IN CONSIDERATION OF THE METHODS OF DEPRECIATION AVAILABLE TO THE TAXPAYERS UNDER SECTION 260(C). ACCORDINGLY, AOGA RECOMMENDS THAT IT BE DELETED.

SECTION 260(J) OF AOGA'S SUGGESTED CHANGES PROVIDES A TRANSITION RULE FOR DEVELOPMENT COSTS FIRST ELIGIBLE FOR DEPRECIATION PRIOR TO JANUARY 1, 1979. THE TRANSITION RULE PROVIDES THAT DEPRECIABLE DEVELOPMENT COSTS INCURRED PRIOR TO JANUARY 1, 1979 ARE TO BE PLACED IN A CLOSED-END COMPOSITE

ACCOUNT. UNDER THIS SUGGESTED TRANSITION RULE, THE TAXPAYER WOULD SELECT ONE OF THE METHODS PRESCRIBED UNDER SECTION 260(C) AND DEPRECIATE ITS UNDEPRECIATED DEVELOPMENT COSTS OVER THE REMAINING USEFUL LIFE OF THE ACCOUNT CONSISTENT WITH THE CHANGE OF METHOD RULES PRESCRIBED UNDER SECTION 260(E). THE REMAINING USEFUL LIFE WOULD BE EQUAL TO 11 YEARS MINUS 1 YEAR FOR EACH TAXABLE YEAR AFTER 1977 TO THE BEGINNING OF THE TAXABLE YEAR. SECTION 260(J) IS DESIGNED TO PROVIDE A SIMPLE TRANSITION INTO THE NEW DEPRECIATION RULES PROVIDED UNDER SECTION 260 WITHOUT CREATING BURDENSOME ADMINISTRATIVE DIFFICULTIES FOR EITHER THE DEPARTMENT OR THE TAXPAYER.

## SECTION 320

The Association has no specific comments with respect to section 320 other than to say we are pleased to note that, consistant with the statute, the proposed regulation incorporates the treatment afforded pipeline dismantling, removal and restoration costs by the Federal Energy Regulatory Commission.

## SECTION 710

AOGA recommends that section 710(f)(2)(A) be amended to refer specifically to 9:00 a.m. Juneau time for notifying the Alaska State Treasury of the amount of the taxpayer's payment. The Association further recommends that section 710(f)(2)(C) requiring the taxpayer to make its tax payment in one lump sum from one bank is unnecessary and could possibly be inconvenient for taxpayers making substantial payments. Thus this provision should be deleted. We have also suggested changes to section 710(f)(2)(D) of the proposed regulations to clarify the situation when the due date is not a banking day.

## SECTION 900

Section 900(24) of the proposed regulations pertaining to the definition of the term "point of production" has been revised to conform to the definitions set forth in AS 43.55.140 (12)(A). Under our interpretation of the statute, the point of production in the case of oil should be the first point downstream of the well where the oil is accurately measured in

A CONDITION OF PIPELINE QUALITY REGARDLESS OF WHETHER THERE IS A CUSTODY TRANSFER METER OR UNIT. IN THE CASE OF GAS, WE BELIEVE THAT THE DISTINCTION SET FORTH IN THE STATUTE BETWEEN GAS WELL GAS AND CASINGHEAD GAS SHOULD BE RECOGNIZED IN THE REGULATIONS.

AOGA ALSO SUGGESTS AS AN ADDITION TO THE DEFINITION OF SALES DELIVERY POINT UNDER SECTION 900(31) OF THE PROPOSED REGULATION, PARAGRAPH (C), WHICH APPARENTLY HAD BEEN INADVERTENTLY OMITTED. PARAGRAPH (C) PERTAINS TO A TAXPAYER'S GAS NOT SOLD AND DELIVERED IN A BONA FIDE, ARM'S-LENGTH SALE TO A THIRD PARTY.

IN LIGHT OF THE CHANGES MADE TO SECTIONS 240(B) AND (C) OF THE PROPOSED REGULATIONS RELATING TO COS[illegible] FOR A[illegible]D IN SUPPORT OF DRILLING, WE HAVE INCLUDED IN OUR SUGGESTED LANGUAGE A DEFINITION OF THE TERMS "COSTS OF DRILLING" AND "DRILLING COSTS" TO INCLUDE COSTS WHICH ARE INCIDENT TO AND NECESSARY FOR DRILLING WELLS AND PREPARING WELLS FOR PRODUCTION.

## EFFECTIVE DATE

AOGA RECOMMENDS THAT THE REGULATIONS BE MADE EFFECTIVE FOR TAX RETURNS FILED AFTER THE DATE THE REGULATIONS, WITH AMENDMENTS, ARE ADOPTED. PURSUANT TO OUR UNDERSTANDING OF THE GENERAL RULES OF ADMINISTRATIVE LAW, THE REGULATIONS MAY NOT BE GIVEN RETROACTIVE EFFECT ABSENT A CLEAR STATEMENT IN THE REGULATIONS EVIDENCING THIS INTENT.

May 19, 1980

Senator Clem Tillion
Senate President
Alaska State Legislature
Pouch V
Juneau, Alaska 99811

Re: Oil and Gas Corporate Income Tax

Dear Clem:

According to members of your chamber, there is a plan afoot to amend the State Oil and Gas Corporate Income Tax to provide a deduction for the Federal windfall profits tax. This will cost the Alaskan public some $8 billion by 1990 -- or $20,000 for every man, woman and child.

As near as can be determined through informal channels, proponents of tax relief for the oil industry are planning to spring this on the Legislature at the last moment, without the benefit of public hearings or input, in the form of a Senate amendment to a House bill, sending the issue immediately to the House for concurrence. Although this is a practice both chambers often resort to, it is hardly the manner in which a revenue issue of this magnitude should be handled. If Sohio, ARCO, and other major oil companies want tax relief, they should plead their case the same way as every other Alaskan group.

Sohio is selling this tax deduction disguised as a question of of form. In its view, it is necessary to make the changes in the state law to avoid double taxation. But the tax question is not just a technical issue, but a political one also, with many options. If we give them the exemption, we could raise the rate of taxation to make up the difference. Or, we could provide the exemption but raise the severance tax to 15%, where it backs out the Federal windfall profits tax. The industry's concern about taxation policy is a concern about the bottom line.

That line could be drawn higher or lower. The Federal windfall profits tax is aimed at a massive windfall that has been realized by the oil industry. Sohio's 1979 profits are up 164 percent over 1978, and 1980 revenues will reflect the benefits of decontrol. The industry's net after-tax revenues for 1980 should reach $3.6 billion, or enough money to provide $36,000 for 100,000 families. By 1983, industry profits are expected to top 5 billion dollars annually, or 20% more than Exxon's record $4.2 billion in earnings this year. These are staggering profits. This year's Prudhoe Bay net profit to the industry will equal 2.5% of all U.S. corporate profits earned in 1979, and 7 percent of all corporate dividends paid in the U.S. last year.

ACO 785862

If we respond to this enormous windfall by lowering the oil company taxes, we will certainly be unique. The rest of the world, and indeed, even some states in the U.S., are considering or have already enacted tough new taxes.

Recent actions in Britian and Norway are a case in point. This is particularly interesting when one considers the different political climates of these countries compared to OPEC nations. One industry analyst notes that "[t]he North Sea is still generally viewed as offering about the world's most attractive economic and political climate for oil exploration. . .offering an unbeatable combination - free market pricing, political stability, and proximity to the world's biggest import market." It is doubly interesting to Alaskans because the British government is a large equity owner in Prudhoe Bay through BP's 53 % ownership of Sohio.

New policy directions taken by the Britons and Norwegians include the following:

1. Higher British Taxes.

   "Oil companies fear the [British] government may once again opt to raise its Petroleum Revenue Tax (PRT) on North Sea profits - 70% from 60% in its new budget this week. That would raise the government share of future oil price rises to 87.5% from 83% now and just 70% when the PRT was initiated in 1975.

   (Petroleum Intelligence Weekly, March 24, 1980)

2. Higher Norwegian taxes.

   "North Sea producers's profits per barrel could be slashed by as much as half by the new tax proposals, which are seen jumping Norway's 'take' to about 85% to 87% from 70% - 79% now. Oslo cites soaring world prices as justifying the rise.'

   (PIW, Feb. 25, 1980)

   The increase in Norwegian taxes includes, among other things, Norway's "special" tax on North Sea profits of 35% to 25%. This "special" tax on profits is not deductable against the Norwegian corporate income tax of 50%. This, of course, is analogous to the situation where the State of Alaska's 9.4 percent tax on profits does not allow a deduction for the Federal Windfall Profits Tax.

3. British ownership of field development. When Margaret Thatcher's tory government was elected, she promised to trim the sails of the government owned British National Oil Corporation (BNOC). Subsquently, members of Ms. Thatcher's cabinent have expressed reservations about the government relinquishing its oil holdings. Now industry experts report that oil companies are unhappy about

   "the proposed British seventh-round licensing terms that would make British National Oil Corp. a co-licensee and continue its rights to 51% of all oil output."

   (PIW, March 24, 1980)

4. Norwegianization of field development.

   "Norway's new White Paper on oil policy is generally being interpreted as a blueprint for accelerating 'Norweglanization' of offshore oil resources and operations. While it is simply an advisory document to be debated in parliament, 'Norway for the Norwegians' is seen likely to be a popular political doctrine. . .

   The document is seen favoring greater use, where feasible, of 100% Norwegian equity in licenses reserved for the three principal Norwegian oil firms - state owned Statoil, state-controlled Norsk Hydro and privde Saga Petroleum. . .

   It's believed likely that unassigned acreage around promising North Sea oil and gas discoveries will go in the future to all-Norwegian ownership.

   (PIW, Feb. 2, 1980)

The tax question is an important one, and given both the recent price hikes and the worldwide reaction, it may make sense to take another look at whether the citizens of this state are getting their fair share. This will not be accomplished by pushing for an 8 billion dollar tax break for the industry in the dying moments of the legislature, with no debate or analysis. I urge you to use your influence to prevent this matter from comming before the Senate this year.

Sincerely,

ALASKA PUBLIC INTEREST RESEARCH GROUP

James Love
Director

enclosures

AGO 785864

Profits of three Prudhoe Bay operators

| company | third quarter $ Mill 1979 | third quarter % Chg v '78 | fourth quarter $ Mill 1979 | fourth quarter % Chg v '78 | full year $ Mill 1979 | full year % Chg v '78 |
|---|---|---|---|---|---|---|
| Arco | 320 | + 45% | 343 | + 54% | 1,166 | + 45 |
| Exxon | 1,145 | + 118 | 1,365 | + 60 | 4,295 | + 55 |
| Sohio | 366 | + 191 | 451 | + 174 | 1,190 | + 164 |

Comparison of Exxon's Prudhoe Bay and worldwide operations, 1979

| | |
|---|---|
| Estimated net revenue from Prudhoe Bay operations | $458 million |
| Estimated tax and royalty payments from Prudhoe Bay operations | 553 million |
| Reported profits from worldwide operations | 4,295 million |
| Alaska net revenue as percentage of worldwide profits | 10.7% |
| Reported taxes paid worldwide | 22,870 million |
| Alaska tax and royalty payments as percentage of worldwide tax payments | 2.4% |

AGO 785865

REPORTS FROM PETROLEUM INTELLIGENCE WEEKLY

BP's net income from Sohio tripled

Continuing to benefit largely from inventory profits and gains in Alaskan income, British Petroleum's 1979 profits more than tripled to $3.6 billion. Indicated fourth-quarter profits also nearly tripled to $9994 million. Sales and operating revenues for the year net of duties and sales tax rose a gentler 28% to $40.5-billion.

BP's net income from Sohio more than tripled to $1.05-billion as Sohio's share of Alaskan oil rose to 675,000 b/d from 579,000 b/d in 1978. BP has a 53% share in Sohio's net profits on Alaskan production between 600,000 and 1.05-million b/d.

March 17, 1980

December 24, 1979 Industry analysis of North Slope profits shows rate-of-return is 47% higher than average return earned by U.S. manufacturing industries. (before decontrol)

"North Slope profits are up more than 100% in 1979, with net after-tax margins now in the area of a handsome $6.20 a barrel, according to a Petroleum Intelligence Weekly analysis. Profits on Alaskan crude have been substantial right from the start of North Slope output in 1977. Even though the producers had some initial difficulty in lining up clients, profits in 1977 ranged from $1.70 to $2.70 a barrel. By early 1979, margins climbed to about $2.50 to $3, then rocketed to $4 in the second quarter, and $6 in the third quarter. . .

The present $7-plus per barrel profit on North Slope crude represents an annualized 22% return on the $14.5-billion invested in Alaska exploration, production and the pipeline, PIW calculates. This compares with a U. Inflation rate of 13% and the genral 15% return earned by U.S. manufacturing industries. In early 1979, the return on North Slope was a bare 10%.

If North Slope crude were 100% free to track runaway OPEC prices now, producers could easily raise selling prices as much as $10 a barrel This would boost after-tax profits by a heady $3.50-$4 a barrel, PIW calculates. Revenues of Alaska and the Federal Government would also climb. For every $1 price rise the companies profits would jump some 35 ¢ to 40 ¢ a barrel, Alaska would get 30 ¢ and the Federal Government 25 ¢, with the rest covering other costs.

Starting Jan. 1980, the price and profit outlook will depend on the combined effects of phased crude price decontrol and the final version of the pending new excise tax on the resulting 'windfall profits.'"

(Petroleum Intelligence Weekly, Dec. 24, 1979)

## GOING TO THE WELL: 'BIG OIL' FIRMS FIND THAT OUTLETS FOR INVESTMENT OF THEIR LARGE EARNINGS ARE LIMITED

Wall Street Journal
April 9, 1980

### Sun Oil Purchases Seagram Co.

Two months ago Jack Neafsey, senior vice president of Sun Co., the nation's 10th largest oil company, was voicing an extraordinary problem: With 1979 profits up by 69%, the company was practically in the position of having too much money to invest at once. The only constraint the company was facing, he said, was "the question of how many opportunities we can take on at one time."

Two days ago, Sun found a place for some of its expansive profits -- it offered $2.3 billion for the bulk of the U.S. oil and gas properties of Seagram Co. The proposed acquisition's price tag was second only to Shell Oil Co.'s $3.65 billion takeover of Belridge Oil Co. last year.

### Exxon has problems spending it's money

For many large U.S. oil concerns the embarrassment of riches brought their way by last year's record profits is both an odd and a vexing problem. Even though their capital budgets are at record levels and far exceed their profits, these companies say they have more financial resources than they can profitably spend.

Exxon Corp., the world's largest oil concern, has a $7.5 billion spending program for this year, a 25% increase from last year's inital appropriation. But Exxon would like to spend even more, says Roger Meadrick, the deputy controller. 'We're not financially constrained from doing so,' he says. 'We're what you might call opportunity-limited.'

### Money is no object

At Standard Oil Co. of California, Mobil Corp., Phillips Petroleum Co. and Getty Oil Co., capital spending is proceeding as though money were no object - which it isn't. "I've told our operating people that if they've got a sound oil and gas project they can handle, don't worry about the money - I'll find a way to get it,' says Howard Bell, California Standard's vice president of finance.

. . .Spending money at home has public-relations value, of course. At one big oil company, there is the rumor that a 'political' percentage was tacked onto the bids that the firm submitted for a big offshore lease sale a few years back. After the tracts had been appraised, a company source says, 'word was going around that the suggested bids were sent up to the chairman's office, and he grossed them up because he wanted our spending figures to look bigger.'

AGO 785868

Prudhoe Bay tax scenarios, 1980 - 1990

oil prices assumes 12% annual inflation in

| year | present state take | Sohio proposal for windfall profits deduction | diff. | McKinnon/ Rogers proposal for 15% severance tax | diff. | 50% state income tax | diff. | proposal for 80% state income tax | diff. |
|---|---|---|---|---|---|---|---|---|---|
| 80 | $ 2,901.5 | $ 2,813.5 | ($ 88.0) | $3,189.2 | $ 287.7 | $5,557.3 | $2,655.8 | $7,368.0 | $4,466.5 |
| 81 | 4,268.8 | 3,974.2 | (294.5) | 4,727.7 | 458.9 | 7,442.9 | 3,174.1 | 10,349.7 | 6,080.9 |
| 82 | 5,058.7 | 4,649.5 | ([illegible]09.2) | 5,646.8 | 58[illegible].1 | 8,576.3 | 3,517.6 | 12,285.1 | 7,226.4 |
| 83 | 5,640.7 | 5,150.6 | (490.1) | 6,346.3 | 705.6 | 9,445.6 | 3,804.9 | 13,754.2 | 8,113.5 |
| 84 | 6,291.9 | 5,708.6 | (583.3) | 7,136.9 | 845.0 | 10,437.3 | 4,145.4 | 15,384.9 | 9,093.0 |
| 85 | 7,035.9 | 6,346.0 | (689.9) | 8,032.1 | 996.2 | 11 597.3 | 4,561.4 | 17,551.5 | 10.515.6 |
| 86 | 7,912.8 | 7,104.0 | (808.8) | 9,031.9 | 1,119.1 | 12,898.8 | 4,986.0 | 19,780.8 | 11,868.0 |
| 87 | 8,887.5 | 7,941.8 | (945.7) | 10,162.0 | 1,274.5 | 14,391.8 | 5,504.3 | 22,528.8 | 13,641.3 |
| 88 | 9,975.5 | 8,873.7 | (1,101.8) | 11,426.7 | 1,451.2 | 16,055.9 | 6,080.4 | 25,409.7 | 15,434.2 |
| 89 | 11,172.5 | 9,890.8 | (1,281.7) | 12,852.8 | 1,680.3 | 18,144.8 | 6,972.3 | 28,903.9 | 17,731.4 |
| 90 | 10.889.2 | 9,596.2 | (1,293.0) | 12,577.0 | 1,687.8 | 17,767.0 | 6,877.2 | 28,296.0 | 17,406.8 |
| | 80,035 | 72,048.9 | (7,986.1) | 96,776.2 | 16,741.2 | 132,315.0 | 52,279.4 | 201,612.5 | 121,577.6 |
| dollars per/ capita | 200,087 | 180,122 | (19,965) | 241,941 | 41,853 | 330,788 | 130,699 | 504,[illegible]31 | 303,944 |
| dollars per/family of four | 800,350 | 720.489 | (79,861) | 967,762 | 167,412 | 1,323,150 | 522,794 | 2,016,125 | 1,215,776 |
| industry dcf rate of return | 26.4 % | 26.66 % | | 26.3 % | | 24.13% | | 20.98% | |

DIVISION OF REVENUE FROM PRUDHOE BAY UNDER DIFFERENT TAXATION SCENARIOS

PRICES INFLATED AT 12%

| TAX SCENARIO | YEAR | STATE TAKE | % | FEDERAL TAKE | % | INDUSTRY NET | % | INDUSTRY NET AS $ PER CAPITA | INDUSTRY NET AS $ PER FAMILY OF 4 |
|---|---|---|---|---|---|---|---|---|---|
| present tax | 80 | $3,106.7 | .34 | $2,432.4 | .27 | $3,627.0 | .40 | $9,068 | $36,270 |
| | 81 | 4,453.0 | .33 | 4,782.0 | .35 | 4,337.7 | .32 | 10,844 | 43,377 |
| | 82 | 5,266.9 | .33 | 6,057.9 | .38 | 4,705.7 | .29 | 11,764 | 47,057 |
| | 83 | 5,893.6 | .33 | 6,961.9 | .39 | 5,006.2 | .28 | 12,516 | 50,062 |
| Sohio proposal for windfall profits tax deduction | | | | | | | | | |
| | 80 | 2,813.5 | .31 | 2,561.4 | .28 | 3,791.2 | .41 | 9,478 | 37,912 |
| | 81 | 3,974.2 | .29 | 5,073.0 | .37 | 4,525.5 | .33 | 11,314 | 45,255 |
| | 82 | 4,649.5 | .29 | 6,461.7 | .40 | 4,919.2 | .31 | 12,298 | 49,192 |
| | 83 | 5,150.6 | .29 | 7,463.1 | .42 | 5,248.0 | .29 | 13.120 | 52,480 |
| McKinnon/Rogers proposal for 15% severance tax | | | | | | | | | |
| | 80 | 3,189.2 | .35 | 2,407.6 | .26 | 3,569.2 | .39 | 8,923 | 35,692 |
| | 81 | 4,727.7 | .35 | 4,699.6 | .35 | 4,145.4 | .31 | 10,364 | 41,454 |
| | 82 | 5,646.8 | .35 | 5,943.9 | .37 | 4,439.8 | .28 | 11,100 | 44,398 |
| | 83 | 6,346.3 | .36 | 6,826.1 | .38 | 4,689.3 | .26 | 11,723 | 46,893 |
| 15% severance tax and 50% state income tax with windfall profits tax deduction | | | | | | | | | |
| | 80 | 5,557.2 | .61 | 1,697.2 | .19 | 1,911.6 | .21 | 4,779 | 19,116 |
| | 81 | 7,442.9 | .55 | 3,885.1 | .29 | 2,244.8 | .17 | 5,612 | 22,448 |
| | 82 | 8,576.3 | .53 | 5,065.1 | .32 | 2,389.1 | .15 | 5,973 | 23,891 |
| | 83 | 9,445.6 | .53 | 5,896.3 | .33 | 2.519.8 | .14 | 6,298 | 25,198 |
| 15% severance tax and 80% state income tax with windfall profits tax deduction | | | | | | | | | |
| | 81 | 7,368.0 | .80 | 1,154.0 | .13 | 644.0 | .07 | 1 610 | 6,440 |
| | 81 | 10,349.7 | .76 | 2,402.6 | .18 | 820.4 | .06 | 2,050 | 8,204 |
| | 82 | 12,285.1 | .77 | 2,846.9 | .18 | 898.5 | .06 | 2,246 | 8,985 |
| | 83 | 13,754.2 | .77 | 3,130.2 | .18 | 977.2 | .05 | 2,443 | 9,772 |

AGO 785870

California considers 10% surtax on oil industry profits.

At the top of the television screen, six pigs snuffle greedily in a trough; at the bottom, hugh profit figures from the oil companies make the sponor's porcine point. 'Sure, big oil companies have a right to reasonable profit,' says the announcer. 'But this year they're eating up more than their share.' A slogan - 'Tax Pig Oil' - flashes onto the screen, and as the voice-over continues, the 'P' fades into a 'B.' 'Let's stick it to Big Oil,' says the announcer. 'They've been sticking it to us for years.'

The Pig ad is a plug for Proposition 11, a California proposal to impose a 10 per cent surtax on oil-company profits. It will appear on the state ballot June 3.

Other states follow suit

Like Proposition 13, the tax slashing measure that inspired simil'ar initiatives in many other states, Prop 11 promises to reverberate far beyond California's borders. Connecticut has already enacted a 2 per cent tax on the gross receipts of big oil companies operating within the state, and at least half a dozen others are considering similar action.

Newsweek, May 19, 1980

Australia increases government "take", keeps 94% of OPEC windfall

Austalia's complex import-parity pricing formula for its 425,000 barrels daily crude oil production is making the government, not the producing companies, the big gainer from the sharp rise in OPEC prices. . .

The government 'take'* on domestic crude has increased as from Jan. 1 to nearly three quarters of the selling price - which PIW estimates at a weighted average $27.55 per barrel - up from two-thirds of an average $21.05 last July. The producers were left a mere 37 ¢ out of the $6.48 average Jan. increase, with the government taking $6.11. . .

* before deducting the state royalty, operating costs, depreciation, and Commonwealth corporate income tax. Thus not to be construed as net profit.

(PIW, March 17, 1980)

AGU 785871